Investigating the Evolution of the East Asian Natural Gas Market: 2016 – 2040

by

Lejla Uzicanin

MBA, Cass Business School, City University London, 2001

BSc., La Roche College, 1997

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Name:	**Lejla Uzicanin**
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Mark Jaccard
Senior Supervisor
Professor

Rose Murphy
Supervisor
Post-Doctoral Fellow

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ABSTRACT

This research project explores how the East Asian natural gas market and its pricing may evolve and how this evolution could impact British Columbia LNG export prospects. The framework for the project is built around an analysis of the likely natural gas demand growth in four countries: Japan, South Korea, Taiwan, and China. The approach involves an analysis of (1) the historical perspective of natural gas markets and international trade, (2) likely natural gas demand growth, supply options and their production costs, and (3) likely supply and demand balances and the prospects for BC LNG export. The research indicates that demand for natural gas in East Asia will continue to grow, with China contributing the most to the region's demand. Given the production and delivery costs of BC's LNG competitors, there is a significant likelihood that the market potential for BC's LNG may be less than predicted back in 2012.

Key words: Natural gas; demand-supply balance; East Asia, China, LNG, natural gas pricing

To my Dad

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LIST OF ABBREVIATIONS

BC	British Columbia
bbl	Barrels
bcf	billion cubic feet
bcfa	billion cubic feet
bcm	billion cubic meters
bcma	billion cubic meters per annum
DOE	U.S. Department of Energy
EJ	Exajoule (10^18 Joules)
GHG	Greenhouse gas
GJ	Gigajoule
GW	Gigawatt
IEA	International Energy Agency
JCC	Japanese Customs Clearing Price for Crude Oil; Japanese Crude Cocktail
Kg	Kilogram
Km	Kilometer
LNG	Liquefied Natural Gas
MMBtu	Million British thermal units
MMtpa	Million tons per annum
Mt	Million tons
tcm	Trillion cubic meters
tcf	Trillion cubic feet

1. INTRODUCTION

Fossil fuels provide the largest share of global energy needs, and natural gas is taking an important place in discussions about global energy balances. Natural gas has been attracting more attention recently; its availability has increased as technological advances enable unconventional gas commercialization, and it is perceived as having environmental advantages over other fossil fuels.

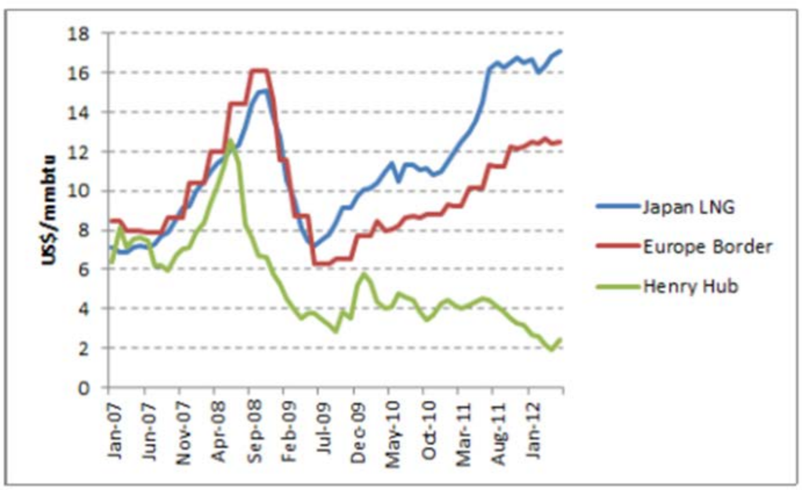
Consumption of natural gas has grown rapidly over the last three decades, and it is set to increase further in the coming years. Many forecasts suggest that natural gas use will increase faster than other major fossil fuels, with expanding trade facilitating transformation of the energy markets as new investments in exploration and production increase the number of buyers and sellers.

Unlike many internationally traded commodities, natural gas has distinct regional markets; however, those markets are increasingly influenced by developments in other parts of the world. Several factors have had a significant impact on the evolution of natural gas markets. On the supply side, natural gas production has increased substantially as technological innovations drastically decreased the production costs of certain unconventional gas sources. Hydraulic fracturing ("fracking") and new drilling techniques lowered the cost of shale gas recovery, making it economically feasible for extraction. Another important factor is the increase in the geographic availability of gas supply as the rise of liquefied natural gas (LNG) impacts global trade. The LNG share of the global gas trade has increased from 18% in 1993 to 31% in 2012, and now represents about 10% of total gas consumed annually (Bradshaw, Herberg, Jaffe, Ma, & Tsafos, 2013; Du & Paltsev, 2014).

On the demand side, East Asia's dramatic economic growth has led to an enormous increase in energy demand over the past two decades, resulting in a growing dependence on imported LNG. As a result, East Asia is a central to the future development of gas markets; natural gas consumption in the region continues to increase sharply, both in terms of the physical volumes and as a share in the world market. The East Asian region has traditionally accounted for two-thirds of the global LNG market, with Japan and South Korea alone typically accounting for over half. Japan's consumption may decrease in the future, however, and South Korea's may grow more slowly over the next twenty years, at the same time that China makes a huge impact on the region's growing demand.

The interest in LNG development and export is driven by the recent large differential in natural gas prices between East Asia and North America — a gap that reached USD 12/MMBtu in 2013 (Figure 1). The emergence of this differential provided an opportunity for new suppliers and traders.

Figure 1: Gas prices in US, Japan, and Europe from the year 2007 to 2012



Source: Henderson, 2012

Canada is one of the countries with abundant reserves of shale gas, and a large portion of those deposits are located in British Columbia (BC). In 2012, the BC Government released its Liquefied Natural Gas Strategy to outline its intent to access the new overseas markets (Asia) via a series of Liquefied Natural Gas facilities and export terminals. The BC Government sees the development of the LNG industry as a great economic opportunity and, as a result, it has projected substantial revenues from anticipated LNG exports. However, estimates of the economic benefits of the new LNG facilities stem from assumptions about the East Asian LNG demand, certainty of BC exports, and record-high prices, all of which are subject to uncertainty. The difference in East Asian and North American gas prices in 2013 indicates a potential opportunity, but a price at one point in time does not inform about the price in 10 - or 20 - years' time. While potential investors in the LNG facilities do not require certainty with respect to future prices, they do require the likelihood that future market prices will be at or above levels that will make their investments worthwhile.

While it may continue to grow, demand for natural gas in the East Asian market is uncertain and contingent on a number of factors; for example, the future of nuclear energy which plays an important role in the energy mix of some East Asian countries. China's demand for gas is one of the biggest uncertainties as it depends on the scale of pipeline gas imports and the future of domestic gas production. Further, the East Asian natural gas demand growth is matched with a substantial LNG supply capacity development.

Major new LNG supplies are expected from Australia, Russia, the United States, and East Africa over the next decade. If all projects targeting the East Asian market proceed as planned, the result may be significant surplus capacity, with many competitors for the gas demands of China, Japan and other countries in the region. BC exporters will face competition from other LNG projects, pipeline imports, and, eventually, from domestic production. In addition, some of those supply options will have lower production costs.

The main objective of this research project is to explore the evolution of the East Asian natural gas market through an assessment of uncertainties related to the future price of natural gas and LNG in that market. In addition, this evaluation seeks to better understand how British Columbia's natural gas export prospects may be impacted by the evolution of the East Asian gas market and thus, if the ambitious development assumptions of the provincial government are valid. My assessment centers on an analysis of the natural gas markets in four East Asian countries: Japan, South Korea, Taiwan, and China. I focus on these countries as the most relevant markets for long-term BC LNG export prospects. The BC Government anticipates substantial public revenues from the new LNG sector, and LNG investors initially expected to secure long-term contracts with pricing based on the traditional oil-indexation. However, market supply and demand dynamics, increasing competition among suppliers, and preferences of the East Asian buyers may make such goals hard to realize. My aim is to increase understanding, and thus reduce uncertainty, about both the East Asia natural gas price determination, and likely long-term price levels, anticipated over a reasonable investment time frame.

The framework for my project is built around an analysis of the likely natural gas demand growth in the four countries. I explore indicative trajectories to identify approximate ranges of demand for each country and the region as a whole. I assess what are the most likely outcomes, subject to various uncertainties and constraints. Further, I examine the likely supply options, which will be competing over the next several decades for the East Asian market and juxtapose those projections to evaluate the probable demand and supply balance for the period 2016 to 2040. Additionally, I consider the likely production costs of those supply options for the East Asian market, which BC LNG exporters will compete with, in order to ascertain the cost competitiveness of suppliers. While East Asian buyers will likely pursue the lowest cost options, other factors, such as diversification and the security of supply, may also be important considerations in selecting suppliers.

There are very few independent assessments of the rapidly developing East Asian gas market, and of those, most are not publicly available. Thus, my research increases levels of awareness about the energy supply and demand transition in the East Asia market, especially as it pertains to natural gas demand and supply, likely future natural gas prices, and likely market opportunities for BC LNG producers. My goal is to contribute to a better understanding of how the East Asian market structure and pricing may evolve under various supply and demand scenarios over the next decades. My research provides insights into the current price setting mechanisms and relevant market dynamics that could influence future price formation methods. For this purpose, I also analyze how other regional gas markets have evolved in order to ascertain what could be the possible routes for the development of East Asian natural gas pricing methods, as well as long-term contract structures that could be anticipated by the prospective suppliers.

There are numerous factors affecting the outlook for the East Asian market and its supply and demand balance. I commence my research with an examination of all possible gas supply options, and then use key information to limit my focus to probable main suppliers toward developing an unbiased, long-term picture of the market. My study does not involve a detailed analysis of all the possible LNG suppliers to East Asia, nor does it assess the spot and short-term supply outlook. Rather, I focus on new and anticipated long-term supply options (and their long-term price projection(s)) expected to compete for market share with BC LNG projects and the resulting dynamics of this interaction.

The research is organized as follows: Chapter 2 provides background information about natural gas characteristics and classifications, and general information about international gas trade and natural gas price determinants. Chapter 3 details the research method, incorporating analysis of the natural gas market's past dynamics, and the analysis of possible future East Asia supply. This is followed by the construction of projection scenarios, and consideration of the demand and supply balance under various constraints, to reflect related uncertainties identified through my research. Chapter 4 includes a review of the East Asian natural gas market to illustrate key market characteristics, and past and future factors affecting natural gas demand within the region. The chapter also identifies supply options to satisfy that demand and reflects on the East Asian market natural gas price levels and price formation. Chapter 5 presents the projected demand ranges for the individual countries and the region as a whole, juxtaposed with anticipated supply for the study period, with a discussion on the likely pathways of supply and demand balances. It also discusses price competitiveness of identified supply options as an important determinant for BC LNG export prospects.

Units

Natural gas data is reported in a variety of ways. For ease of understanding and comparisons, all the quantities are reported by volume in billion cubic meters (bcm).
One billion cubic meter is equal to 35.3 billion cubic feet (bcf) and to 0.74 million tons (Mt).
Prices of gas are expressed in US dollars per millions of British thermal units ($/MMBtu).

Unless otherwise indicated, all currency values are in 2015 US dollars.

2. BACKGROUND

This chapter provides background information about natural gas characteristics and classifications, and general information on international gas trade and the main regional markets. It concludes with a short discussion on the different natural gas pricing methods used throughout world gas markets.

2.1. Natural Gas Characteristics and Classifications

Natural gas is a type of fossil fuel, and it plays an increasingly important global role as a source of energy. Fossil fuels are compounds consisting of carbon and hydrogen formed in the past from the remains of living organisms. Due to their high energy density (the amount of energy stored per unit of mass or volume), fossil fuels store and deliver large quantities of energy effectively and consistently, which makes them an attractive option for human energy needs. The primary chemical component of natural gas is methane (CH_4). When it is chilled to a temperature of about minus 160° Celsius under atmospheric pressure, natural gas becomes liquefied natural gas (LNG).

Natural gas is found in a variety of subsurface locations, differing in degrees of gas quality. It is important to distinguish between "resource" and "reserves". Resource is the entire quantity, the estimated global natural occurrence of natural gas. These estimates are uncertain and include deposits of various quality. Reserves are a sub-set of resource, and include quantities where location and magnitude is known with some certainty. Reserves are available for exploitation with existing technologies and at production costs below (or not much above) the market price, enabling economic recovery. Resources (at any point in time) are fixed, since the earth is finite, while reserve quantities change over time due to new knowledge, technologies, and economic conditions that enable their extraction. Differentiation between reserves and resources is linked to future market prices and long-run cost of production; increases in market prices and decreases in production costs augment reserves by “moving” quantities of resource into this category.

Estimates of natural gas reserves make a distinction between conventional and unconventional gas. This distinction is not based on the final product, but rather on the characteristics of the deposits. Conventional gas is found in deposits with high permeability and is exploited with conventional technology, whereas unconventional gas is found in accumulations where permeability is low and its exploitation requires unconventional recovery techniques. Conventional natural gas is found in two primary forms: “associated” gas, found together with oil, and “non-associated” gas, which is found in reservoirs that do not contain oil. Unconventional resources generally cannot be extracted with the technology used to exploit conventional resources: their recovery is enabled by advanced production technology such as horizontal drilling and hydraulic fracturing. Extraction and use of such resources, therefore, involves different production logistics and cost profiles. The “Global Energy Assessment – Toward a Sustainable Future” (2012) describes unconventional natural gas resources as coal-bed methane, shale gas, tight reservoir gas, water-dissolved gas and methane hydrates.

Coal-bed methane (CBM) is natural gas hosted in seams of coal. Due to low pressures and low well-head flow rates, the production is economically feasible only for considerable coal basins located near gas-demand centers with a substantial population.

Shale gas occurs in a variety of rock types with low permeability. Shale is a sedimentary rock and acts as a reservoir. Production of shale gas requires artificial stimulation, such as hydraulic fracturing, which increases production costs. Hydraulic fracturing produces fractures in the rock formation that stimulate the flow of natural gas, increasing recovery volumes. Fractures are created by pumping large quantities of fluids at high pressure into the target rock formation. Hydraulic fracturing fluid commonly consists of water, proppant (a solid material, typically sand) and chemical additives that open and enlarge fractures within the rock formation.

Tight reservoir gas (tight sands) occurs in a variety of rock types with low permeability and at depths of up to 4500 meters. These geological structures can be found everywhere in the world, and gas production from these reservoirs is developing in countries with mature gas industries.

Gas in deep reservoirs is gas from deep sedimentary basins located in depths over 4500 meters, usually associated with high pressures and temperatures. Exploration and production is technologically challenging and there are only few examples of deep-gas production (US, North Europe, Russia).

Water-dissolved (aquifer) gas refers to methane dissolved and dispersed in groundwater. It can be found practically everywhere as almost all porous rock formations below groundwater tables contain small amounts of methane. The gas contained in aquifers exceeds reserves of conventional gas by two orders of magnitude, but, even with new extraction technology, only a small percentage of this gas is expected to become commercially viable.

Gas hydrates are crystallized ice-like mixtures of natural gas. The gas is contained within cavities formed by lattices of water molecules. Such hydrates exist in permafrost regions, and near or below the sea floor. The volume of natural gas contained in the world's gas hydrate accumulations exceeds that of known gas reserves. The use of this gas resource has not been commercially viable, mainly because other sources of gas are cheaper; however, research aiming to develop technologies for commercial exploitation of gas hydrates is ongoing ("Global Energy Assessment - Toward a Sustainable Future," 2012). Table 1 presents estimates of global unconventional gas resources.

Table 1: Global unconventional gas resources

	Tm^3	EJ
Deep reservoirs (depth 4500 – 7000 meters)	200 - 300	7500 – 11,200
CBM (up to 4500 meters depth)	200 - 250	7500 - 9300
Shale gas	380 - 420	14,000 – 15,500
Dense reservoirs (tight sends) gas	180 - 220	6700 - 8200
Water-dissolved (aquifer) gas	8000 – 10,000	300,000 – 370,000
Gas of hydrates (including permafrost metastable hydrates)	2500 – 21,000	90,000 – 780,000

Data from "Global Energy Assessment – Toward a Sustainable Future (2012)

The distribution of conventional natural gas sources is concentrated geographically, with Qatar, Russia, and Iran as the largest resource holders. Unconventional deposits are more widely distributed with two-thirds of the assessed technologically recoverable shale gas resource concentrated in six countries: U.S., China, Argentina, Algeria, Canada and Mexico (The U.S. Energy Information Administration (EIA/ARI), 2013).

Compared with other types of fossil fuels, natural gas has the lowest carbon intensity and, therefore, emits less carbon dioxide (CO_2) per unit of energy. As such, natural gas is sometimes promoted as an important fuel in the transition to low-carbon energy systems, primarily by displacing other fossil fuels in electricity generation. Despite its advantages relative to other fossil fuels, natural gas combustion still causes CO_2 emissions, and the natural gas industry is associated with methane emissions, another potent greenhouse gas (GHG).

2.2. Natural Gas Regional Markets

The gas market appears to be much less integrated than oil or coal markets, and three distinct regional markets can be identified: North American, European, and Asia-Pacific. Each has a different market structure, degree of market maturity, supply sources, and level of dependence on imports. One obvious difference is that both North American and European markets are mature pipeline gas markets with limited reliance on LNG. Furthermore, both North America and Europe have already created trading hubs as part of the reform processes of the sector ("deregulation" in North America, and "liberalization" in Europe) (Stern, 2014).

Considering physical inter-linkages and the prevailing natural gas pricing mechanism, the North American market is highly integrated. The European gas market developed later than in North America; it is more diverse in terms of market characteristics between different countries and existing pricing mechanisms within the region. In contrast, the East Asian market is not interconnected by pipelines, and the countries are almost totally dependent on imported LNG. The exception is China, which, on top of its domestic natural gas production, already imports pipeline gas from Central Asia and Myanmar. The East Asian market encompasses natural gas markets in various stages of development. Established and mature LNG markets include Japan, Korea, and Taiwan, while China is an emerging, high-growth market.

2.3. Natural Gas Transportation and LNG Trade

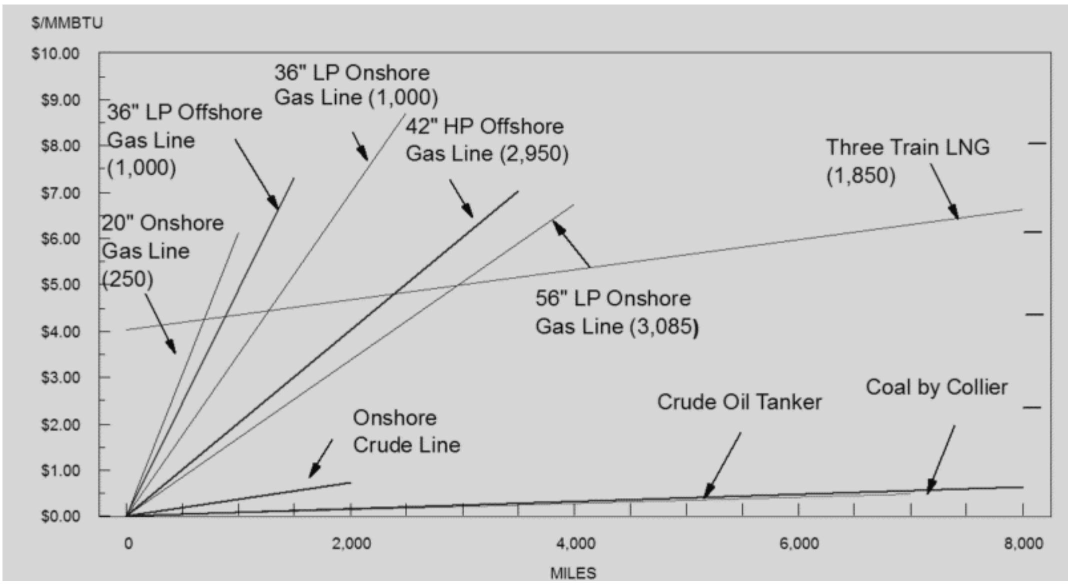
Because of its gaseous form and low energy density compared to oil, natural gas is disadvantaged in terms of its transportation and storage. Oil has the highest energy density of all fossil fuels and, as a liquid at ambient temperature and pressure conditions, can be easily transported over long distances by a variety of means, with associated costs generally comprising a small fraction of the overall cost of supplying the product. This has facilitated the development of a global market in oil, where multiple supply sources serve multiple markets at transparent spot prices, reflecting demand and supply balance and the differences in transportation costs and oil quality.

In contrast, long distance transportation of natural gas represents a relatively large fraction of the total supply cost, with delivery either via special tankers such as LNG, or long-distance pipelines. Under atmospheric pressure, natural gas has only one thousandth of the energy density of oil. Natural gas' energy density can be increased by a factor of 600 by cooling to form LNG. Natural gas in its liquid state is more feasible and economical to transport over long distances than in its gaseous state. Figure 2 provides an illustrative cost of natural gas and oil transportation, taking into consideration the effect of scale[1]. It presents a comparison of transportation costs for gas, oil and coal. In regard to gas, it offers illustrative costs of onshore and offshore (high pressure and low

[1] Figure represents 2011 cost levels (Jensen, 2013).

pressure) pipelines, as well as LNG (consisting of 3 production units). The numbers in parenthesis refer to gas delivery capability in million cubic feet per day.

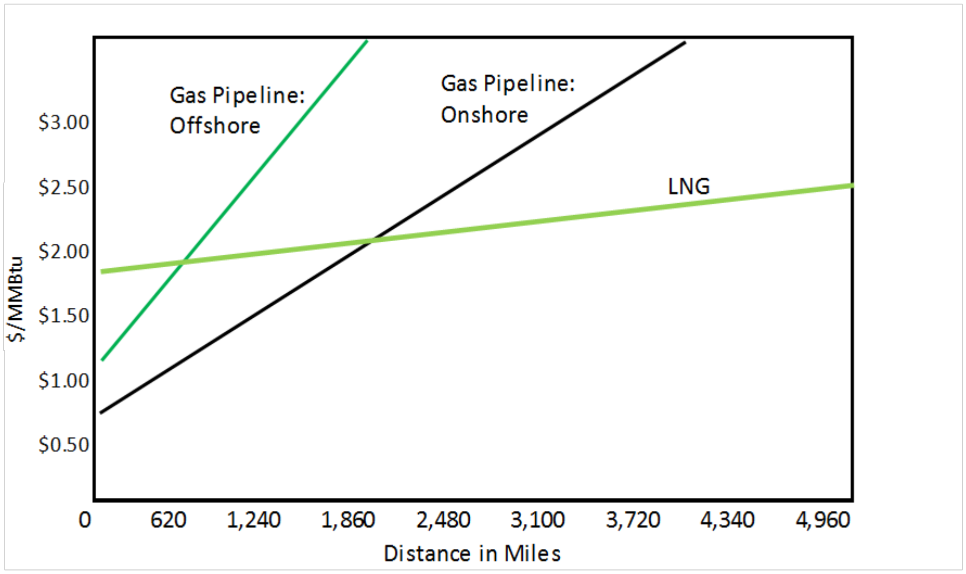
Figure 2: Illustrative cost of natural gas and oil transportation



Source: Jensen, 2013

The key factors in determining the most economic transportation method for a given supply route are the distance and the volumes transported. For long-distances, pipeline transportation is preferred — except in cases where transport requires crossing oceans or long stretches of water, in which case LNG transport is more economical. As shown in Figure 3, as the distance over which natural gas must be transported increases, the use of LNG has economic advantages over the use of pipelines (Cornot-Gandolphe, Appert, Dickel, Chabrelie, & Rojey, 2003; Michot Foss, 2007).

Figure 3: Natural gas transportation cost relative to distance

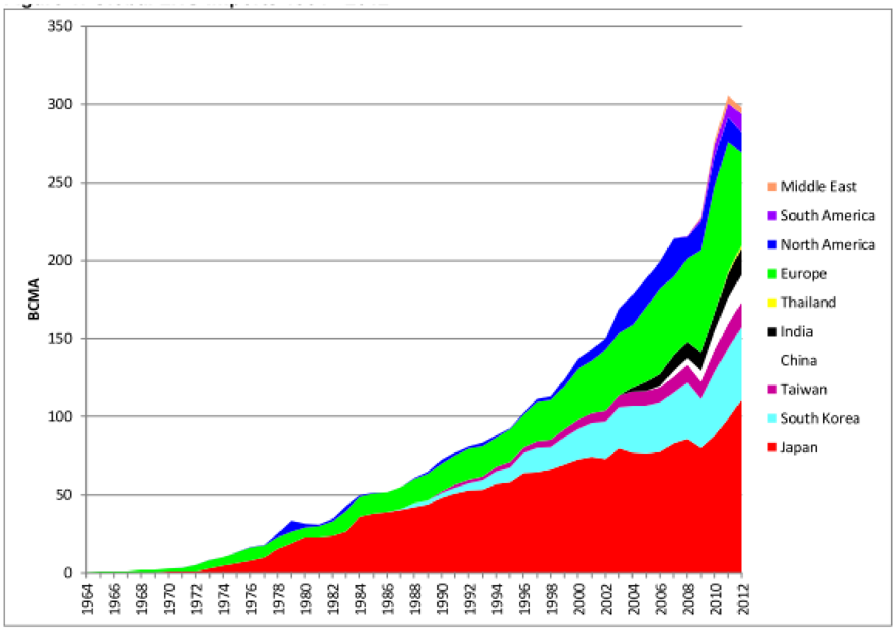


Adopted from: Michot Foss (2007), Introduction to LNG

<u>LNG Trade</u>

International trade of LNG began with trial shipments from Louisiana to Canvey Island (UK) in 1954. The first commercial shipments started in 1964, with transport of LNG from Algeria to the UK. This was followed by ventures between Algeria and France in 1965, and Alaska and Japan in 1969 (Julius & Mshayekhi, 1990). Since the late 1970s, trade shifted to the Pacific. LNG imports in East Asia increased rapidly and, by 1997, Korea, Japan and Taiwan alone accounted for 76% of the world's total LNG imports (Energy Charter Secretariat, 2009). The Pacific Basin is likely to remain the largest source of demand for the foreseeable future. Figure 4 shows a pattern of global LNG imports from 1964 to 2012.

Figure 4: Global LNG imports 1964 - 2012



Source: Rogers and Stern, 2014

LNG supply is far more flexible than pipeline gas since cargo ships can go anywhere in the world, making LNG an important facilitator for the wider integration of natural gas markets. LNG trade enables wider-ranging supply, overcoming various constraints that international pipelines face (e.g. the crossing of a number of countries and borders, with possible unstable political situations, requirements for right-of-way negotiations, etc.). The cost of LNG supply has been reduced in the last several years, largely due to increases in train size (LNG production unit), improved fuel efficiency in liquefaction and re-gasification, improved equipment design, and better utilization of available capacity.

The International Gas Union observes that LNG is the fastest-growing component of expanding international natural gas trade, increasing by 7.5% per annum on average since 2000. In 1990, only 4% of globally consumed gas was transported as LNG, compared to 10% in 2014 (with domestic production accounting for 69%, and imports via pipeline accounting for the remaining 21% of consumption). Today LNG trade represents approximately 30% of total international natural gas trade. The growing number of countries that are suppliers or buyers of LNG further illustrates the expansion in LNG's share of the natural gas market: in 2006, 13 countries were LNG exporters while 15 countries were importers. In 2014, 19 countries were exporters while 29 countries were importers. The number of countries importing LNG is expected to increase to 33 with new re-gasification terminals in Jordan, Egypt, Pakistan and Poland (The International Gas Union, 2014, 2015; Leidos, 2014).

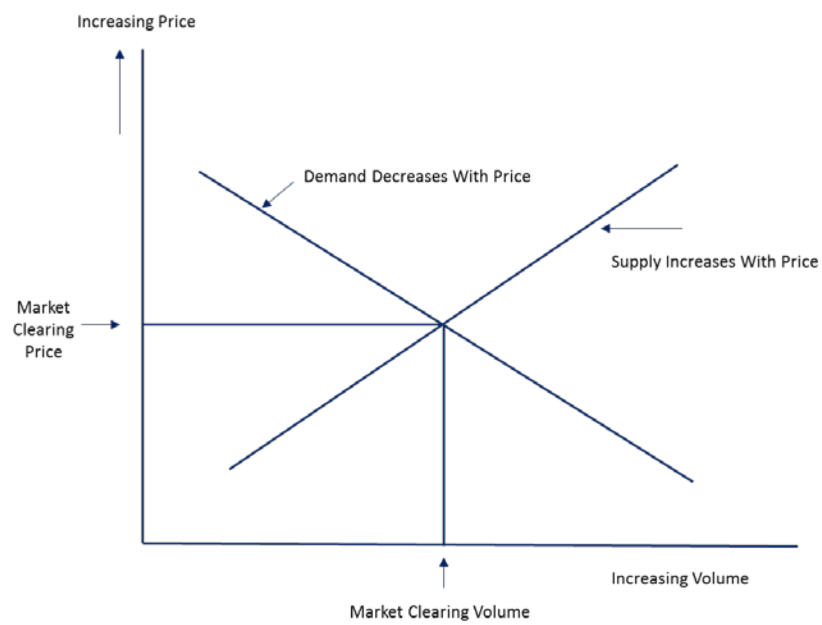
2.4. Natural Gas Price Formation

The economic analysis of fossil fuel pricing has largely been concentrated on the implications of the fuels being non-renewable resources and their optimal use. The basic principles of non-renewable resource economics were developed by Harold Hotelling (1931). In "The Economics of Exhaustible Resources", Hotelling suggests that, under conditions of perfect information about the resource stock and future demand, the net price (market price minus marginal cost) of a non-renewable resource should rise at the interest rate (or discount rate), implying that the price of the resource should increase through time (Livernois, 2009; Pindyck, 1978). In other words, the price of a non-renewable resource includes an extraction cost and a depletion premium or "scarcity rent" (a form of economic rent) and, therefore, should be rising through time.

The Hotelling concept has been the subject of many analyses, mainly with respect to oil and, to a lesser extent, natural gas. Generally, however, its empirical significance has not been confirmed in practice (Livernois, 2009). For example, through technological innovations and economic incentives, reserves can be maintained or increased through further geological exploration. This implies uncertainty about the finite quantity of a resource that may be exhausted over time. The intuition of Hotelling should not be disregarded, however, as producers could make choices over depletion rates and, in that context, consider their expectations of the likely course of future prices. Such decisions could be seen as "political" (e.g. the decision by the Qatari government in 2005 to put a moratorium on further increases in production in excess of committed projects) or have an economic explanation, if returns at the margin from additional production are deemed smaller than the value of leaving the gas underground (Stern, 2012).

Economic theory suggests that the pricing of any good is set by the intersection of its aggregate demand and supply curves (Figure 5). Consequently, it would be natural to think that the price of a commodity such as natural gas is determined in an open market through interactions between many buyers and sellers, where market competition would drive equilibrium prices towards the long run marginal costs of gas supply at a value just necessary to meet its demand.

Figure 5: Theoretical behaviour of supply and demand in a well-functioning competitive market



Each supplier's participation in the market depends on the cost of its production. Suppliers with a cost of production below the market-clearing price will find buyers, while extra marginal suppliers (those with production cost over the market-clearing price) are excluded from the market. The marginal producer, or the highest-cost producer, recovers his/her full production cost (including a normal return on capital), whereas infra-marginal producers earn more than the full cost of the production, as the return earned depends on the cost of production. When a new supplier offers his/her product to the market, the precise impact of the introduction of additional supply will depend on its place on the supply curve. A lower cost producer can compete with other suppliers and, if demand does not rise by a corresponding amount, this new supplier will force higher cost suppliers out of the market.

The difference in production costs between the highest cost producer and all lower cost producers in the market is called differential rent (Ricardo, 1871). It reflects different costs of production due to the heterogeneous quality of the resource: some sources are cheaper to find and produce while others are more expensive. Costs of production differ between small and large fields, or conventional and non-conventional resources. Further, production site locations relative to potential markets also give rise to differential rents, as this affects the transportation cost of one source relative to others.

There are also other factors influencing the cost competitiveness of supplies in a given market. An important aspect is the type of initial investment, which can be brownfield or greenfield. Greenfield developments are built from scratch on a new site without existing infrastructure. Brownfield projects can be less costly due to savings from reduced site preparation and use of existing infrastructure. In addition, “bargaining powers” of either suppliers or sellers is an important consideration as the outcomes regarding pricing depend also on market positions. When offered supply exceeds demand at a certain price, there is likely to be downward pressure on price in sales negotiations.

As noted, the global gas market is not as integrated as that of oil, and international gas trade is not necessarily conducted at prices which reflect the demand and supply balance and the differences in transportation costs. Indeed, international gas markets depart from the ideal commodity competitive conditions, with mechanisms for price formation differing between regional markets. Since 2005, the International Gas

Union (IGU) has been reviewing the evolution of pricing mechanisms at the wholesale level across the world. The IGU has developed a classification system for price formation mechanisms, presented below, as a result of six surveys carried out between 2005 and 2013 (Table 2).

- *Oil Price Escalation* in the literature is also referred to as “oil linked” or “oil indexed” pricing. Here, the price is linked to competing fuels, typically crude oil. In some cases, coal prices, as well as electricity prices could be used for indexation.
- *Gas-on-gas competition* is also referred to as hub-based, spot, or market pricing. In this case, price is determined by the interplay of supply and demand, and gas is traded over a variety of different periods (daily, monthly, annually etc.). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. National Balancing Point NBP in the UK). Gas is purchased and sold on a short-term, fixed price basis. There are longer-term contracts, but these use gas price indices to determine the price (rather than competing fuel indices). Spot LNG trade falls in this category.
- *Bilateral Monopoly* is a mechanism where price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time. Often, the arrangement is at the government or state-owned company level. Typically, there is a single dominant buyer or seller on at least one side of the transaction, distinguishing this category from GOG, where there would be multiple buyers and sellers.
- *Netback from Final Product* pricing is where the price received by the gas supplier is linked to the price of the buyer’s final product. This may be the case where the gas is used as a feedstock in chemical plants (e.g. ammonia), and is the major variable cost in producing the product.
- *Regulation-Cost of Services* where the price is set, or approved, by a regulatory authority, or possibly a Ministry, to cover the “cost of service”, including the recovery of investment and a reasonable rate of return.

➢ *Regulation- Social and Political* where the price is set, on an irregular basis, by a relevant Ministry, on a political / social basis.

➢ *Regulation-Below Cost* where the price is knowingly set below the average cost of producing and transporting the gas as a form of state subsidy to domestic consumers.

➢ *No Price* where gas is provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants or in refinery process and enhanced oil recovery.

Table 2: Gas pricing mechanisms

Mechanism	Description
Oil Price Escalation	The price is linked to competing oil products.
Gas-on-Gas Competition	The price is determined by the interplay of supply and demand, gas-on-gas competition.
Bilateral Monopoly	The price determined by bilateral agreements between a large seller and a large buyer; often the arrangement is at the government or state-owned company level.
Netback from Final Product	The price is linked to the buyer's end product; the price received by the supplier is a function of the price received by the buyer for the final product the buyer produces.
Regulation: Cost of Service	The price is set, or approved, by a regulatory authority, or possibly a Ministry, to cover the "cost of service".
Regulation: Social and Political	The price is set by a relevant ministry, on a political / social basis.
Regulation: Below Cost	The price is set below the cost and subsidized.
No Price	The gas produced is either provided for free to the population and industry, or in refinery process and enhanced oil recovery.

Source: IGU, Wholesale Gas Price Survey 2014

Oil indexation and gas-on-gas competition are the two main price formation mechanisms in the international gas trade. Oil indexation originated in Europe in the

1960s and spread to Asia. A contrasting mechanism, based on gas-to-gas competition and hub pricing, developed in North America and spread to Europe via the UK, where both of these two pricing mechanisms exist today.

The share of the gas-to-gas competition pricing method has been increasing progressively. In international trade in North America, prices are based on gas-on-gas pricing. In Europe, oil indexation still prevails, but the use of gas-on-gas pricing has steadily increased from 6% of trades in 2005 to 33% of trades in 2010. In the East Asian market, oil indexation is dominant and was used for 88% of gas trades in 2010 (Leidos, 2014).

2.5. Regional Markets and Differences in Natural Gas Pricing

North America

Gas prices in the US are driven primarily by supply and demand fundamentals of the domestic gas market. In 1978, the US Congress enacted legislation that aimed to create a less controlled natural gas market by which competition and market forces would determine the wholesale price of natural gas. The US, followed by Canada, was the first country in the world to move to spot pricing at a hub by removing regulation of upstream and midstream pricing and liberalizing access to pipelines (deregulation). This led to the establishment of market pricing based on the Henry Hub spot, and after 1990, the New York Mercantile Exchange (NYMEX) futures prices[2]. As a consequence, North American gas prices are primarily a result of supply and demand interaction in the domestic gas market, with Henry Hub generally viewed as the reference point.

[2] The NYMEX futures contracts are used as an international benchmark price; the contracts trade in units of 10,000 million British thermal units (MMBtu) and the price is based on delivery at the Henry Hub (Bradshaw et al., 2013).

Europe

Within Europe, the United Kingdom (UK) is a distinct natural gas market, differing in terms of its market pricing mechanism from continental Europe. The UK market, liberalized during the 1990s, created the National Balancing Point (NBP), a hub with a reference price across the whole country (Rogers & Stern, 2014). In contrast to that, the continental European gas market has been dominated by long-term (15-25 year) oil-indexed contracts for pipelines and LNG imports. However, the rationale for oil-indexation — that the end-user's choice is between burning gas and oil products — started weakening in the 1990s and throughout the 2000s. These shifting market conditions and pro-competition regulatory initiatives at the European Union level (combined with decreased demand, especially after the 2008 financial crisis) prompted the emergence of contracts with gas-on-gas pricing which provided lower price alternatives to oil-indexed supply.

Trading at Europe's natural gas hubs and exchanges has evolved, though Stern (2012) notes that there are still questions as to whether they have sufficient trade activity to be price reference points, aside from the UK NBP hub where trading volumes in 2010 were larger than the entire continental Europe combined. In continental Europe, the reform process is still ongoing, and it will take more time to move fully to hub prices. In 2012, of all the continental European hubs, the Dutch TTF has the most trading volume, followed by Germany's NCG (but at a much lower extent), while other hubs' trading volumes were at even lower levels (Stern, 2012).

In 2012, diverse pricing formation mechanisms could be identified in different European regions. Hub trading is most advanced in the north-west European region where competition is strongest; elsewhere in Europe, hubs are less advanced or in the development process. In Northwestern Europe, (Belgium, Denmark, France, Germany, Ireland, Netherlands, and UK) which represents 50% of European gas demand, nearly three quarters of gas traded was based on spot prices at the gas trading hubs. In Central Europe, (Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland), 48% of gas was priced at hub levels, while in the Mediterranean region (Italy, Portugal, Spain, Turkey), only 12% was hub-based. The South East Europe region (Bosnia, Bulgaria, Croatia, Former Yugoslav Republic of Macedonia, Romania, Serbia, Slovenia) still remains dominated by oil-linked pricing (The International Gas Union, 2013; Rogers & Stern, 2014).

East Asia

The majority of LNG trade flows in East Asia are conducted under long-term contracts with prices linked to the value of oil. Crude oil price linkage was introduced into the Japanese LNG import contracts in the 1970s, when Japan was the only country in Asia importing LNG. The early pricing clauses tied the price to crude oil, hence the so-called Japanese Customs Clearing Price for Crude Oil or "the Japanese Crude Cocktail (JCC)" (Energy Charter Secretariat, 2009). When the first LNG contracts were negotiated, Japanese power generation was heavily dependent on heavy fuel oil, which has been increasingly displaced with natural gas. As new East Asian importers entered the market (Korea in 1986, Taiwan in 1990, and China in 2006), they also adopted oil price indexation. Over time, there have been some variations in the formulae, but the basic approach has remained unchanged. The formula of the typical Asian contract is in the form:

$$P(LNG) = A \times P(Crude\ Oil) + B$$

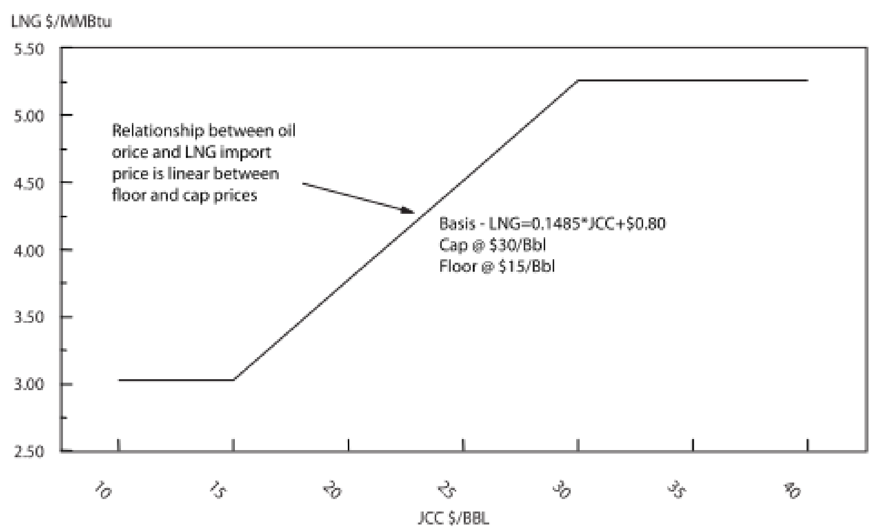
where

- P(LNG) is price of LNG in US$/MMBtu;
- P(Crude Oil) is price of crude oil in $/bbl; and
- A and B are constants negotiated by the buyer and seller (Rogers & Stern, 2014).

The constant A is known as "the slope", linking the JCC quotation with the LNG price and typically expressed as a percentage. Assuming heating value equivalence between oil and gas, the slope would be 17.2% (0.172), implying that, at an oil price of US$100/bbl, the LNG price would be US$17.20/MMBtu. The range of the slope in the majority of LNG contracts is 12-16%. Before the collapse of oil prices in late 2014, the oil indexed price formulae for recently signed long-term LNG contracts ranged between 13% JCC and 14.85% JCC + 0.5% (Gomes, 2015).

One of the features of the Pacific Basin market was the development of "S curves" as a way of reducing price risks for contractual parties. For the sellers, the risk was an oil price collapse, so they were interested in some form of price floor, while buyers wanted upside protection or some form of a price ceiling. The S-curve formula reflects a contractual relationship between the price of LNG and crude oil, but it contains a price ceiling and a price floor to moderate the impacts of extreme changes of crude oil prices (Figure 6).

Figure 6: Illustration of Asian market S-curve based on JCC price



Source: Energy Charter Secretariat, 2007

2.6. Sales Contracts Features

The traditional LNG contract involves a structured long-term contract between the buyer and seller. The vast majority of international gas trade outside North America is still conducted on the basis of the long-term contracts (10–30 years) (Stern, 2014). In addition to the duration, the contracts address LNG quantity, price, and transportation responsibility. The delivery modalities defined in the contracts are either free on board (FOB) or delivered ex-ship (DES):

- With "*free on board*" (FOB) deliveries, the transfer of risk occurs when LNG passes the ship's rail at the port of departure; at this point, all costs and liabilities of transporting the LNG to the port of destination transfers to the buyer. FOB delivery allows the buyer greater flexibility with regard to destinations of shipments and for reselling;
- With "*delivery ex-ship*" (DES) the cargo is delivered at destination port after the liquefaction phase and transported to the import terminal. DES contracts have a destination clause which limits the flexibility to resell or redirect LNG. To redirect a cargo, the buyer must engage in negotiation with the seller or incur reloading and shipping costs at the port of delivery (International Energy Agency, 2014d).

The quantity of LNG that the buyer must purchase is usually "take or pay", in which the buyer must pay for the agreed volumes, regardless of whether or not they take the volumes. Most contracts feature these take-or-pay provisions to ensure that the buyer guarantees a minimum payment.

Contract prices are periodically adjusted to the price of oil, in accordance with the contractual formula. In European oil-indexed contracts, prices are adjusted quarterly, based on an average of oil product prices in the preceding 6-9 months, often with a lag of three months (Rogers & Stern, 2014; Stern, 2012). Asian contract prices are adjusted to the price of oil with time-lags of 3-9 months (Gomes, 2015).

In European contracts, however, there is a limited opportunity to make a change to the contract price through a price review process. Stern (2012) elaborates that this feature is enabled by the price re-opener clauses as European long-term contracts have 3-year review built in. The rationale for the price review is to examine (as initiated by either buyer or seller) if there has been "changed economic circumstances beyond the control of the parties to the contract" which would justify a change in the base price or the indexation formula. Failure to agree on a new price level following this review would trigger an arbitration clause in the contract.

Provisions calling for regular price reviews have not been included in most long-term contracts in East Asia. Although recent contracts with East Asian buyers have included references to price-re-opener options, they typically lack specifics about conditions that could trigger renegotiation and contain little about the factors that would be considered in case any negotiations take place (Rogers & Stern, 2014; Stern, 2012).

3. METHODS

In this research project, I follow an eclectic methodological approach to establish ranges of possible natural gas demand, supply and probable long-run market prices in the East Asian market. For the purposes of my research, the East Asian region encompasses four countries: Japan, South Korea, and Taiwan, which are mature LNG markets, and China, the high-growth, emerging LNG market. I focus on these four countries as their markets may be of particular interest to BC LNG exporters due to their demand levels and supply options.

I start with an analysis of international gas trading, and how it has evolved, before making a more detailed examination of East Asian market attributes. I continue with an investigation of past supply-and-demand-side characteristics, and their interplay in determining the features of the respective natural gas markets. Through a historical perspective of regional markets and international trade, I make inferences about the present context and dynamic factors which may shape the future development of the East Asian natural gas market. I also study natural gas pricing determinants, and the underlying factors that influence their prevalence in the respective markets. Consequently, I analyze the key factors influencing pricing patterns in order to understand the possible pathways for the future development of the East Asian market in terms of its trade and natural gas pricing.

The particular focus of my project is on the evolving conditions of the four East Asian LNG importing countries. I examine their individual consumption patterns and evaluate the current and future key factors, policies, and events which may influence demand in order to develop illustrative projections of future natural gas needs, both at the individual country and at the regional market level for the period 2016 to 2040. My goal is to establish a general framework for the market. To simplify the research, I do not account for the existing contractual commitments, but instead focus on estimating the probable total demand.

In order to establish the supply and demand balance for each country, I assess the natural gas supply options, both pipeline and LNG (and their likely market prices), which could satisfy future demand. In particular, I focus on potential North American, Australian, East African, Russian, and Central Asian supplies (pipeline or LNG, as applicable). To investigate the effects of supply coming into the region, combined with the expected demand in the four countries, I develop likely scenarios of demand and supply balances, taking into consideration various uncertainties. I focus on potential long-term supply and do not consider spot or short-term supply for the region. As China has vast indigenous unconventional gas resources, I also develop projections for feasible domestic production levels in China to establish the likely quantity of natural gas demand that may be satisfied by domestic production. In this way, I theorize a probable demand volume that could be filled by imported natural gas.

To obtain the necessary data for the scenarios, I review forecasts and reports by leading teams of experts and modellers researching the East Asian natural gas market. The underlying forecast assumptions reveal what the leading researchers consider to be the most important drivers of the long-term demand for natural gas and the plausible supply options. In addition, I explore the economic, technological, geopolitical, and environmental factors that, in the long term, may affect the natural gas demand for East Asian countries. I also consider the potential supply sources, both in terms of the probable quantity and timing at which they may enter the market and their respective prices. Based on my research, I determine which factors will likely affect natural gas consumption and supply options. By synthetizing all gathered information, I develop a set of assumptions for the demand and supply scenarios I construct for the individual countries.

I incorporate uncertainties by setting baseline and upper bounds for possible future demand in each of the four countries. Demand could also be lower than expected in East Asia, which would result in limited prospects for BC LNG exports. Since my objective is to probe the circumstances under which there would be an opportunity for BC exports, I do not consider a lower demand scenario. I concentrate my efforts on studying two scenarios. The first scenario is what I consider my base, and the most likely, scenario. The second scenario is an exploration of the conditions under which demand would exceed this baseline case. Also, I reflect on various constraints related to supply options and test the outcome compared to the total volumes predicted to be available for the East Asian buyers. Finally, I estimate the likely supply and demand balance and project the future range of the East Asian market in which potential BC LNG exporters would compete.

Through my research, I gather information about the likely price levels per unit of LNG and pipeline supply which will be competing to satisfy East Asian natural gas demand. To complete my analysis, I consider the prospects for BC LNG exports, taking into account projected demand, supply options and their price competitiveness (unless otherwise indicated, all currency values are in 2015 US dollars). I assume that the lowest cost suppliers will be able to enter (or maintain) a share of the market in the long term and, based on supply and demand projections, consider what might be the benchmark price levels setting the competitiveness threshold.

Figure 7 outlines the steps in my analysis of the East Asia natural gas market:

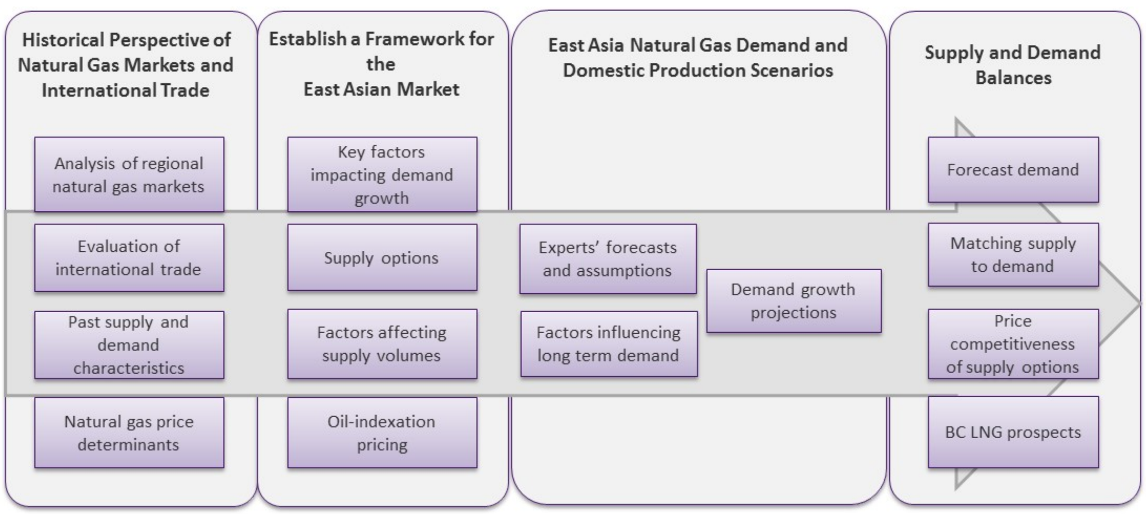
- The historical perspective of natural gas markets and international trade
    - Regional natural gas markets
    - Natural gas transport and international trade
    - Major historical supply and demand characteristics
    - Natural gas price determinants and regional differences
- Establishing a framework for the East Asian Market
    - Examination of four East Asian countries, including their past consumption patterns and key factors that will shape their future demand growth
    - Natural gas supply options for the region
    - Factors that could affect natural gas supply coming to the market
    - The oil-indexation pricing method in the East Asian market
- Develop scenarios for natural gas demand and domestic production in East Asia

- Review forecasts and underlying assumptions of the natural gas market in East Asia by leading teams of experts
- Explore technological, economic, geopolitical and other factors that, in the long-run, may affect the natural gas demand in East Asia
- Based on all gathered information, establish assumptions and demand growth rate projections (and projections of domestic natural gas production, where applicable)

➢ Determine likely supply and demand balances

- Forecast demand for the four individual countries and the East Asian market
- Match projected demand with likely supply competing to satisfy it
- Consider price competitiveness of supply options
- Assess the prospects for BC LNG export, considering price competitiveness relative to other suppliers.

Figure 7: General framework for analysis of East Asia natural gas market



4. ANALYSIS

The first part of this section presents an overview of the East Asian gas market, focusing on the differing characteristics of the four individual countries. As the markets are dynamic, it is important to understand the current and emerging economic, energy, and environmental trends which could have profound impacts on natural gas demand in the region. I then examine supply options for the region, and uncertainties related to the potential suppliers. Combined with the anticipated demand volumes, this information indicates the possible scope and scale of the natural gas market in East Asia. Further, I explore implications for natural gas and LNG price levels and the likely evolution of the natural gas pricing mechanisms in the East Asian market.

The world's natural gas demand has been largely driven by the rapid growth of consumption in Asia; a consequence of the region's strong economic growth over the past several decades and an increased demand for every energy source. Table 3 presents East Asian countries' and global natural gas consumption in 1990 and 2014. Natural gas demand in the East Asian region is likely to continue to grow, with the biggest growth anticipated for China. However, China's demand for imports appears to present the biggest uncertainty for this market as it depends on many factors, including the scale of domestic shale gas production and the prospects for pipeline gas imports from Central Asia and Russia. Demand in other East Asian countries is also uncertain, bearing in mind possible slower economic growth than in previous periods and policies concerning nuclear energy.

Table 3: East Asian countries and global natural gas consumption

	1990	**2014** (*estimates*)
(*bcm*)		
China	16	182
Japan	58	134
South Korea	3	48
Taiwan	1.7	17
World	2,050	3,500

Data from International Energy Agency, Natural Gas Information, 2014, 2015

For policymakers in the region, energy security and an adequate supply for the growing economy have been the critical strategic and economic concerns, but going forward, other issues stand to influence natural gas demand growth, including:

- the future structure of the economy;
- implementation of environmental policies related to acid rain and GHGs, as well as improving on air quality;
- the future role of nuclear energy, considering government policies and potential public opposition to nuclear expansion;
- the ability to satisfy energy demand with indigenous supply of both fossil fuels and renewable energy;
- implementation of policies toward energy conservation and improvement of energy intensity;
- availability of natural gas supply, including alternative options such as pipeline supply and natural gas price competitiveness compared to other fuels.

4.1. China’s Natural Gas Market

China’s energy sector is undergoing a profound transformation. Primary energy consumption is slowing down, and coal consumption even fell in 2014, with a continued fall in early 2015 (Green & Stern, 2015). Environmental policies are expected to bring changes to the energy sector. In 2014, the Chinese government announced strengthened national action to address air pollution and climate change. President Xi Jinping called for an “energy revolution” to tackle demand and supply bottlenecks, and the environmental impacts from the production and consumption of energy, while Premier Li Keqiang announced a “war on pollution” (International Energy Agency, 2015a). The Chinese government set a target to raise non-fossil fuel energy consumption to 15% of the energy mix by 2020 and to 20% by 2030 in an effort to ease the country's dependence on coal. In addition to that, the Government’s aim is to increase the use of natural gas as a cleaner burning fossil fuel (US Energy Information

Administration, 2015a). Given the Chinese government's goals, combined with a determination to develop its domestic unconventional gas production sector, a "golden era" for natural gas in China might be emerging.

In 2014, coal supplied over 66% of China's total energy consumption, which contributed heavily to the country's local air pollution and global CO_2 emissions. Table 4 presents China's primary energy consumption in 2014.

Table 4: China primary energy consumption - 2014

	Exajoule	%
Oil	21.8	17.5%
Gas	7	5.6%
Coal	82.2	66.1%
Nuclear	1.2	1%
Hydro-electricity	10	8%
Other renewables	2.2	1.8%
TOTAL	124.4	100

Data from BP, 2015

China is the world's most populous country and has a rapidly growing economy, which has been driving the country's overall energy demand. In the past, China's energy demand has been driven mainly by the rapid growth of its industry. Future energy demand likely will grow at a slower rate, due to slower growth of GDP, which declined from 9.5% in 2011 to 7.8% in 2012, 7.7% in 2013 and (estimated) 7.4% in 2014, with expectations for a further decline to 6.9% by 2017 (World Bank, 2015a, 2015b). In addition, slower energy demand growth will result from energy conservation efforts and structural changes in the economy toward less energy-intensive industries. China aims to move toward high-tech and value-added industries: four out of seven industries identified as "strategic emerging industries" are related to low-carbon technology (Asia Pacific Energy Research Centre, 2013). These factors imply a significant reduction of the economy's energy intensity — the ratio of energy use to economic output (E/GDP).

According to the IEA, China remains the driver behind global gas demand and, by itself, is responsible for half of the world's growing gas consumption (International Energy Agency, 2014c). Natural gas use in China has increased rapidly over the past decade. Since 2000, China has seen gas demand grow at an average of 16% per annum, which has turned the country into one of largest consumers of natural gas, with total consumption in 2012 at 144 bcm. In 2013, China's gas import dependence reached 32%, compared to just 2% in 2006. The country currently has just under 50 bcma of re-gasification capacity, with a further 50 bcm under construction or planned. Table 5 presents China's natural gas consumption since 1990, in comparison to several other key natural gas consuming countries.

Table 5: China's natural gas consumption compared to other large natural gas consuming countries

	1990	2000	2010	2012
(bcm)				
China	16	24.5	105.5	144
South Korea	3	19	43	50
Japan	58	84	109	132
Germany	68	88	94	86
India	13	28	64	57
USA	530	661	683	723
Canada	67	91.5	97.5	106

Data from International Energy Agency (2014), Natural Gas Information

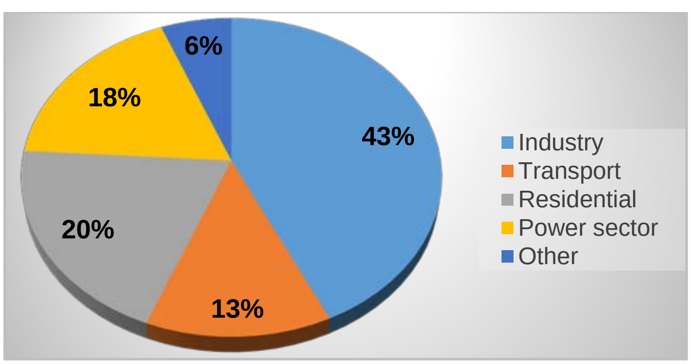
The role of natural gas in China's energy structure remains low and, at present, accounts only for 5.9% of total primary energy consumption, which is much lower than the world average of 23.7% (BP, 2015; Jaffe et al., 2015). In 2014, China's natural gas consumption rose to 181 bcm annually (bcma), compared to 753 bcma in the USA ("Enerdata: Global Energy Statistical Yearbook," 2015). China has plans to increase natural gas use for environmental reasons, due to its advantages over other fossil fuels in terms of lower carbon emissions and lesser air pollution. The Government's determination to increase natural gas use is demonstrated by the State Council statement (2014) approving the proposal by the National Development and Reform

Commission to establish a mechanism that would ensure the stability of long-term gas supply (M. Chen, 2014). To meet the projected long-term demand, the country has many supply options, including increased domestic production, pipeline gas from Central Asia, Myanmar, and Russia, and various supply options of LNG along the eastern coast.

__Natural Gas Use by Sector__

Chen (2014) provides a sectoral breakdown of gas demand in 2012. The majority of gas consumption stems from industrial users. However, demand in the transportation sector has risen over the past decade due to China's expansion of its natural gas vehicle fleet, and residential demand was boosted by the rapid development of the pipeline network which, in turn, enabled more than 20 million urban residents to gain access to gas each year (M. Chen, 2014). Gas utilization for electricity baseload generation is restricted and is, therefore, not widespread (International Energy Agency, 2015a). Figure 8 provides a sectoral breakdown of gas demand in 2012.

Figure 8: China's natural gas demand by sector



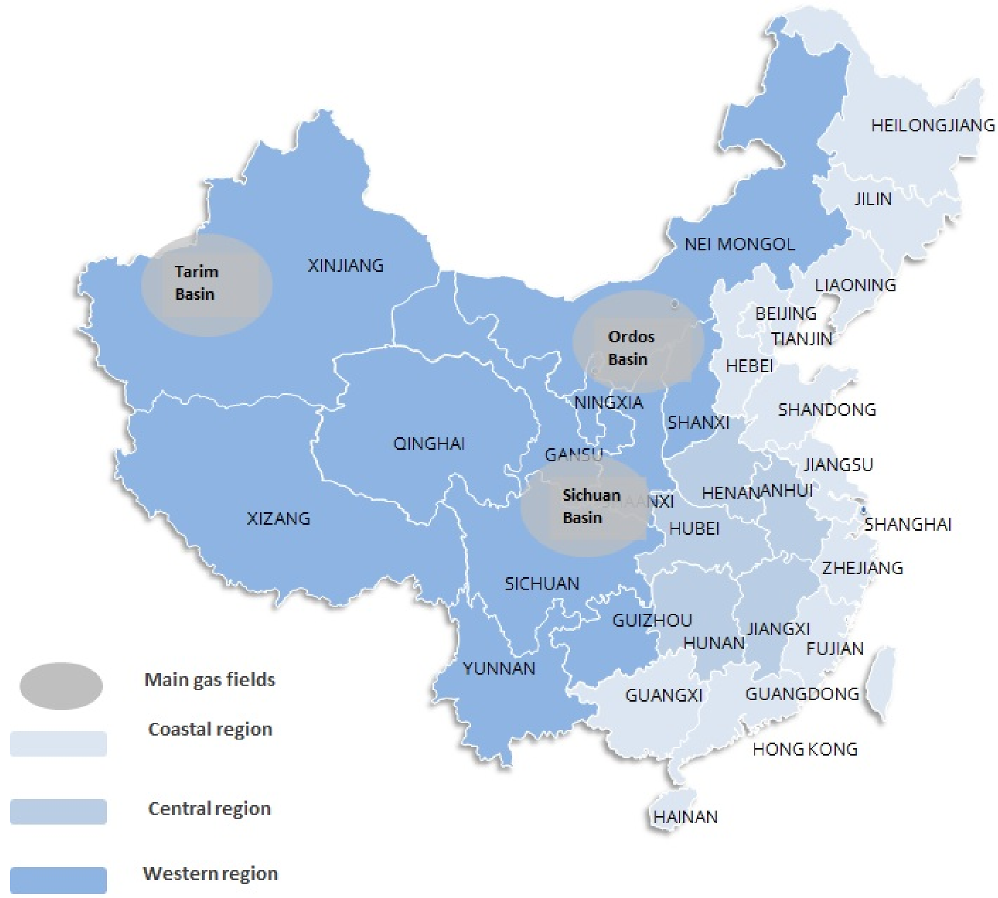
Data from: M. Chen, 2014

Among the government's various policies influencing energy mix is the *Natural Gas Guideline*, which provides detailed instructions regarding natural gas use in different sectors. The 2nd edition of the Guideline was published at the end of 2012 by the National Energy Agency (NEA), categorizing all gas usages into four groups: A "prioritized", B "allowed", C "restricted", and D "prohibited". The Guideline reveals the Chinese government's intention to incentivize the use of natural gas in some sectors and prevent its use in others. For example, in the transportation sector, the use of LNG as a transportation fuel appeared for the first time in the 2012 guidelines and is a prioritized category. On the other hand, use of gas for baseload electricity generation is prohibited in the 13 major coal producing areas (Y. Chen, 2013).

Regional Variations

Most natural gas consumption in China takes place in the eastern coastal provinces, while most natural gas production occurs in the western provinces. The coastal and central regions combined account for 60% of national gas demand. The western region produces 60% of national gas supply and supplies gas to the central and coastal provinces, although some provinces in the western region import gas from Central Asia and Myanmar. Western China has three top-producing basins — Ordos, Sichuan and Tarim. The coastal region receives its gas supply either from neighbouring regions via pipeline or from LNG imports. The central region, being closer to the domestic gas sources, gets almost all of its gas from the western region. The central region is a transit corridor for Central Asian and western region gas to the coast, and many of the major cities are key gas transit points (Figure 9) (M. Chen, 2014).

Figure 9: China's regions and main gas fields

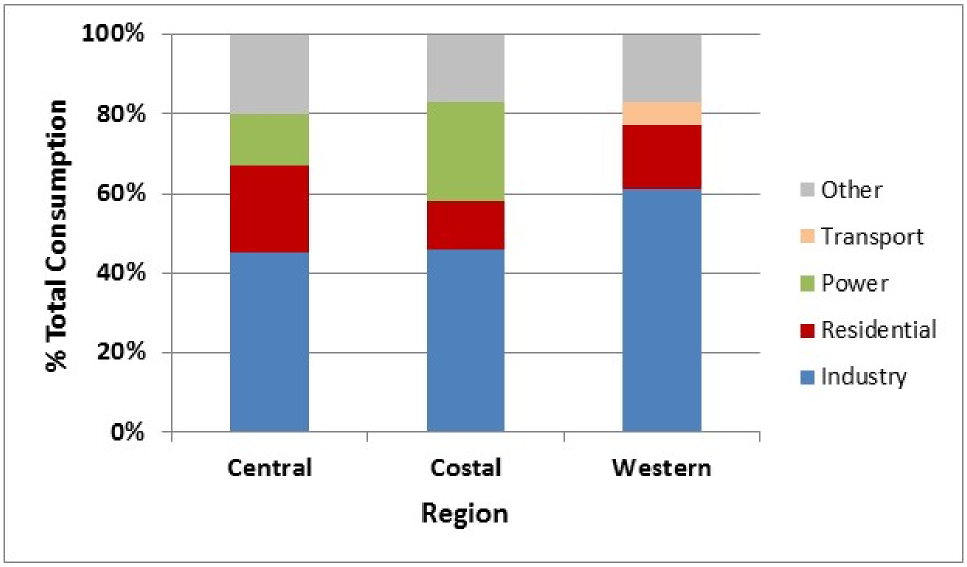


Adopted from: M. Chen (2014), The Development of Chinese Gas Pricing: Drivers, Challenges and Implications for Demand

The consumption patterns of different regions show significant differences:

- In the coastal region, the industry and power sectors account for most gas consumption, 46% and 25%, respectively, and the residential sector makes up 12% of the demand.
- In the central region, industry accounts for 45%, residential 22%, and the power-sector 13% of gas consumption.
- In the western region, industry consumption accounts for 61%, residential 16% and transport 6% of gas consumption (Figure 10) (M. Chen, 2014).

Figure 10: China regional natural gas consumption patterns



Data from M. Chen, 2014

Chen (2014) notes that, going forward, the coastal region is likely to continue experiencing a growing demand for power and heating. The central region will carry on with urbanization and experience a boom in residential and industrial gas use, while the arrival of Central Asian gas and enhanced regional pipeline connectivity improves its access to gas. The western region is expected to drive demand for gas in the transportation sector, owing to the availability of indigenous gas.

Connectivity between the regions is being enhanced through the construction of new inter-regional pipelines and storage facilities. This enhanced connectivity will enable diversification of supply and supply price options as the new volumes of pipeline and LNG imports enter the Chinese gas market, together with anticipated domestically produced gas. Consequently, the new LNG imports could face more intense competition from pipeline imports — even in some coastal provinces as these become supplied by Central Asian gas and pipeline supply from Russia (M. Chen, 2014).

Gas Price Reform

In an effort to support the expansion of natural gas consumption, the Chinese government commenced natural gas price reform in the form of a market-oriented pricing mechanism for domestic consumption. Gas pricing in China entails a complex mixture of agreements for different sources and end-users; the reform will lead to consolidation of these arrangements into a single national pricing system (International Energy Agency, 2015b). As higher prices for gas imports were not reflected in the fixed, regulated domestic prices, the reform aims to adjust domestic prices to levels that will enable coverage of the average costs of imported gas (M. Chen, 2014; Stern, 2012). Further, China's large shale gas resources are expected to have a higher production cost than that of conventional gas, and the higher gas prices would likely boost domestic gas production (International Energy Agency, 2014d).

Gas price reform started in 2011 with a pilot program in the southern provinces of Guangdong and Guangxi. Following the pilot phase, China rolled out nationwide reforms for the non-residential sector, mainly industrial users and electric power generators. The new pricing system links natural gas prices at the city-gate to the price of imported oil products. The linked prices are discounted to ensure a price advantage for natural gas rather than coal. The pricing scheme covers natural gas from imported pipeline gas, most domestic onshore sources, and LNG imports sent through pipelines. Prices for shale gas, coalbed methane, and coal-to-gas, and LNG imports sold at the terminal for local distribution can be negotiated between the producer and the buyer and are not subject to regulation (US Energy Information Administration, 2015a).

In July 2013, the reform created two categories of prices, one for existing demand based on 2012 consumption (Tier 1), and the second category for any gas consumption above the 2012 levels (Tier 2). The average price for all Tier 1 customers increased by about 15% and the average price for Tier 2 was set higher than Tier 1. The second phase of the reform proceeded in 2014 when the prices for existing demand (Tier 1) were increased again (by around 20%). In the third phase, which took effect April 1, 2015, the government combined the prices of the two Tiers into one price, resulting in an average price of $10.62/MMBtu. The overall result is that the average regulated city-gate prices increased by more than 36% between the time prior to the reforms in 2013 and the completion of the third phase in 2015 (US Energy Information Administration, 2015). In addition to this, the Government announced plans to create more market-based rates for residential customers.

The China Energy Fund Committee (2013) emphasizes the view of some researchers that the gas price reform must be combined with electricity price reform if China is to promote the use of natural gas in the power generation sector. Under the existing gas pricing and on-grid tariff system, gas-fired power plants cannot generate profit without government subsidies because the cost of operating most gas power plants in China is much higher than the electricity tariff (China Energy Fund Committee (CEFC), 2013). For example, in Guangdong, the average generation cost of a gas power plant after completion of the pilot price reform remained close to RMB 0.81 (USD 0.12) per kilowatt hour (kwh), which was higher than the RMB 0.74 (USD 0.11)[3] per kwh local on-grid tariff at the time. Subsequent phases of the gas price reform likely resulted in an even larger gap between the gas power plants' operating costs and the on-grid tariff. While many local governments reduced the price gap by providing subsidies, it is questionable whether they will be able to sustain them. As indicated by experts, China needs an integrated nation-wide electricity pricing system that can reflect the full generation costs of the generating plants using different fuels before natural gas will be widely used in electricity generation (China Energy Fund Committee (CEFC), 2013).

Other Reforms in the Energy Sector

In addition to the reforms mentioned previously, China announced other market-oriented changes. One radical change for the state company CNPC, the owner of most of the pipeline network, is to separate control of transmission from control of gas

[3] Based on the conversion rate on December 12 2015, RMB 1 – USD 0.1548

supplies. These changes are designed to ensure that pipeline operators provide access to third parties under fair conditions, which would also improve access to some upstream resources for non-state-owned companies, particularly for shale gas and other unconventional gas types. Currently, the production of small and mid-sized gas producers is limited as their option is either to sell the supplies to CNPC or to develop gas for local consumption. China's National Energy Administration believes that introducing these changes will stimulate exploration and domestic production. Development of unconventional gas supplies, primarily from coal-bed methane or shale gas, may already be attractive to private investors as a significant number of local, privately owned Chinese companies are involved in owning and developing these resources.

Key Demand Factors

Going forward, several factors will impact natural gas demand growth in China:

1) Environmental policies aiming to replace coal with gas;
2) Supply availability and production cost, of domestic production in particular;
3) Implementation of energy sector reforms, such as gas price reforms, electricity price reforms, and overall evolving energy demand under the economic rebalancing, and
4) Price competitiveness of gas compared with competing fuels.

Currently, the Chinese government has a growing interest in natural gas consumption in order to address environmental issues: local air pollution and GHG emissions. For the first time, environmental, rather than economic policy, will be the main driver behind Chinese energy policies (M. Chen, 2014). Domestic air pollution provides an incentive for the Chinese government to increase the proportion of natural gas in the energy mix. Indeed, public concern with air pollution is a motivation for the Central Government to enforce a higher gas consumption share at the provincial and municipal levels. In addition to that, addressing CO_2 emissions and a low-carbon economy has become an international priority. China has made commitments to lower its carbon intensity (CO_2 emissions per unit of GDP) and, more recently, to reach a peak in absolute emissions by 2030, which would decline thereafter. Natural gas, as a cleaner source of energy than coal, could help China fulfill its pledge to the global community.

Because of growing demand, China's energy import dependence has been increasing and the Government is seeking ways to improve energy security. The country has significant unconventional gas resources, and development of its indigenous production could help improve the security of supply, as well as secure more favourably priced supply than imported gas. As elaborated in section 4.3, China's domestic production could rapidly increase in the coming years. In a planned economy, with gas demand regulated by the authorities (who allow defined levels of consumption or restrict gas use in certain regions), demand growth projections to a large extent reflect expectations concerning domestic natural gas production growth (Mitrova, 2014). Therefore, a future increase in the demand for natural gas does not necessarily lead to an increase in gas imports.

4.2. Natural Gas Markets of Japan, South Korea, and Taiwan

Economic growth in these three other East Asian countries will continue to drive energy demand, although at a slower pace than that of previous periods. Environmental policies and policies focused on the use of other fuels will shape the future role of natural gas in their energy sectors. Particularly, policies concerning nuclear power will have a significant impact on natural gas demand in the region. Further, the three countries are promoting an increase in the renewable energy share of primary energy supply in order to improve security of supply and address environmental concerns. While the extent to which renewable energy targets are met is not certain, a trend toward an increase of renewables in the energy mix may reduce growth in natural gas demand in these East Asian countries.

Japan's Natural Gas Demand

Japan is an isolated market with very limited indigenous fossil fuel energy resources. It was traditionally the largest natural gas market in Asia, and is expected to remain the largest LNG importing country in the region for the foreseeable future. Almost all of the demand (99%) is satisfied by imported gas, and since Japan does not have gas pipeline connections to other markets, it is fully dependent on LNG imports. However, Japan has significant potential sources of renewable energy such as solar, wind, hydro, and geothermal. Energy shares in 2013 are 45% oil, 26.5% coal, 23.3% natural gas, 1.5% hydro, 0.5% nuclear and 3.2% for other energy sources (International Energy Agency, 2014c).

The role of nuclear energy in Japan, especially after the 2011 Fukushima nuclear accident, considerably affects the outlook for natural gas demand. The Fukushima disaster caused the Japanese government to rethink its use of nuclear energy due to the immense security concerns raised after the earthquake. Following the accident, Japan shut down 49 GW of nuclear capacity and replaced this output with increased generation from imported oil, coal, and LNG. The result was a substantial increase in the natural gas demand (and LNG import) due to boosted gas-fired power generation. Restarting all the idled reactors beyond 2020 could displace up to ~55 bcma of imported LNG, assuming the proportion of fuels return to the same levels as before 2011 (Goncalves, 2014).

In April 2014, Japan approved its new Strategic Energy Plan which calls for the restart of most of its nuclear reactors (48 in total), once the necessary regulatory approvals are in place. The plan, however, does not specify targets for the future share of fuels in the energy mix (International Energy Agency, 2014d). Coal is a viable option as it benefits from lower power generation costs relative to natural gas. The new strategy indicates that coal will be an important baseload fuel in the power sector. In addition to the anticipated gradual return of nuclear energy, the Strategic Energy Plan also emphasizes energy conservation measures and the expansion of renewable energy.

Considering the re-start of the currently idle nuclear power facilities, it is likely that natural gas consumption will decrease and return to pre-Fukushima levels. The uncertainty, however, is around the pace of this decrease, as the timeline of the restart is still undefined, so different trajectories for demand - and LNG imports - are possible. Even in the case of a slow re-activation, gas consumption is likely to decrease due to a flattening electricity demand caused by weak economic growth, increased efficiency and the deployment of renewables.

South Korea's Natural Gas Demand

South Korea's expanding economy has caused strong energy demand growth. South Korea has the highest energy intensity in the OECD, along with one of the highest levels of per capita consumption of electricity in the Asia-Pacific region (International Energy Agency, 2012). Estimated shares of fuels in the total primary energy supply are: 36.5% oil, 29.4% coal, 18.2% natural gas, 13.8% nuclear; 0.1% hydro; and 2% other (International Energy Agency, 2014c).

Energy security is an important issue for South Korea due to its heavy reliance on external supplies of energy sources, with more than 95% of its energy requirements being imported (Norton Rose Fulbright, 2014). In 2013 the country was the 2nd largest importer of liquefied natural gas (LNG), the 4th of coal, and the 5th of total petroleum (US Energy Information Administration, 2014a). 99% of natural gas demand is satisfied by imported gas in the form of LNG as South Korea has no pipeline connections to other countries. Japan and South Korea together are responsible for more than 50% of global LNG trade (International Energy Agency, 2014d, 2015a).

Over the past two decades, South Korea's economy has become heavily industrialized, placing the country among the OECD's top CO_2 emitting nations. The Government has committed to reducing GHG emissions by 30% by 2020, compared to its business as usual case, and to reduce the economy's dependence on fossil fuels (Asia

Pacific Energy Research Centre, 2013). In 2012, the Government announced an emissions trading scheme (ETS), which was launched in January 2015. It covers about two-thirds of the country's total emissions, and with a cap of 573 MtCO2e in 2015, it is the second largest ETS worldwide after the EU ETS (International Carbon Action Partnership (ICAP), 2015).

Nuclear energy has retained a high share of the power generation mix over the last two decades. However, due to safety concerns triggered by a scandal involving fake certificates and substandard parts and Japan's Fukushima accident, the long-term role of nuclear energy is uncertain. Even though there is a general understanding of the potential benefits of nuclear energy by the South Korean public, acceptance of a new power plant at the local level could prove to be a barrier for further expansion. Korea's new Basic Energy Plan, approved in 2014, revises the share of installed nuclear capacity downward, reducing the target of 41% to 29% of the power generation mix by 2030. As of September 2014, there are new nuclear power plant units of 6.6 GW capacity under construction. Of the already existing 23 nuclear power units, 16 are due to be retired before 2040 unless their operating licenses are extended (International Energy Agency, 2014d).

The Government also announced plans to increase the use of renewable energy and has established an 11% target for renewable energy in the total primary energy supply by 2030 (Asia Pacific Energy Research Centre, 2013). Unlike the target for nuclear power, the goal for renewable energy in the Basic Energy Plan has remained the same at 11%. Consequently, this leaves a gap which may be closed with natural gas or coal. An opportunity for natural gas to increase its share of the energy mix therefore exists, though one of the threats to that opportunity is the cost competitiveness of imported gas compared to coal.

Rapidly rising power demand has encouraged investment in new coal-fired plants, indicating that South Korea is likely to continue to rely on fossil fuels for a substantial part of its energy demand in the coming decades. The Electricity Plan released in January 2014 shows that the Government plans to increase coal-fired power generation capacity by 45 GW by 2027 (Power-technology.com, 2015). In 2013, the Government projected a 1.7% annual demand increase for natural gas until 2035. However, this increase will likely result from consumption by the industrial sector, while gas usage in the power sector (which accounts for about 50% of the total) is likely to remain the same. As South Korea expands its coal-fired power generation facilities with 12.5 GW of new capacity expected to be online by the end of 2017, baseload generation will be increasingly provided by coal and nuclear, leaving a limited opportunity for additional gas consumption (International Energy Agency, 2015a).

Taiwan's Natural Gas Demand

Taiwan's energy demand has been growing as the country transformed itself from an underdeveloped, agricultural island to an economic power. In 2011, energy consumption by industrial sectors accounted for about 46% of the total, transportation 12%, residential 11%, and services 11% (J.-Y. Chen, 2014).

Oil and coal made up 41% and 34% of Taiwan's total primary energy consumption in 2013 respectively, while the remainder was mostly natural gas, nuclear, and smaller amounts of renewable energy. Taiwan has very limited indigenous energy resources. Domestic natural gas provides just 0.1% of the economy's primary supply, hydro provides 0.3%, and geothermal, solar and wind power combined provide 0.2% (US Energy Information Administration, 2014b). Nearly all of the natural gas consumed is imported in the form of LNG. In 2013, Taiwan imported more than 17 bcm, making it the world's fifth largest LNG importer (US Energy Information Administration, 2014b).

Traditionally, Taiwan's key energy policy focus has been on security of supply, though the focus now also includes sustainability, environmental issues and economic competitiveness. The country adopted a renewable energy act which aims to promote the use of renewable energy, boost energy diversification, and facilitate reduction of GHG emissions. Going forward, Taiwan is expected to continue a transformation to a high technology and service-oriented economy, with reduced overall energy intensity of its economic output (Huang, Bor, & Peng, 2011). Therefore, energy demand growth may be lower than its historical highs due to the structural changes in the economy toward non-energy-intensive industries and efforts to reduce energy intensity.

Currently, there are three nuclear power plants operating in Taiwan, each with two units, with a total of over 4.9 GW of capacity in operation. These three existing plants are reaching their retirement age and are slated to be decommissioned starting in 2019. Taiwan commenced the construction of a fourth nuclear facility with two reactors and a capacity of 2.7 GW. The facility was nearly complete and scheduled to commence with operations in 2015. However, Japan's Fukushima disaster in 2011 tempered public sentiment towards nuclear power. As active seismic faults run across the country, there are views that Taiwan may not be a suitable location for nuclear plants (Bradshaw et al., 2013). Due to public pressure, construction of the fourth plant stopped in early 2014. The first of the two reactors was to be sealed after safety checks, and the construction of the second reactor was halted (ABC News, 2014).

Going forward, the biggest uncertainty regarding demand for natural gas in Taiwan is the future of existing nuclear plants and the status of the one in the construction phase. In case of no extension to the lifespan, the three existing nuclear power plants (six units) will be decommissioned, starting in 2018 or 2019 with all units expected to be decommissioned by 2025.

4.3. Natural Gas Supply Options for East Asian Countries

Japan, Korea and Taiwan have zero, or very little, domestic production of natural gas. Without any pipeline connections, all three countries are completely dependent on LNG imports to satisfy their consumption needs. In comparison, China already receives pipeline gas supply and is the place where LNG and pipeline gas converge on the continent. The interplay of pipeline, LNG imports, and domestic supply gives China a key role for the future of the East Asian natural gas market; these elements also make China the major source of market uncertainty.

A number of countries with the potential to export LNG to East Asia are anticipating a significant market potential, and to this end are already expanding or anticipating the expansion of LNG production capability. This additional supply is projected to come on stream in the next several years. At the same time, however, pipeline gas supply to China will increase, with substantial volumes coming from Russia and possibly other countries. If all the potential supply projects proceed, the result could be a significant surplus capacity in the East Asian market in the next several decades. I assess this potential in the following sections of this report.

China's Domestic Natural Gas Production

To meet its future demand, China's natural gas supply will come from three main sources, each of which faces various uncertainties: domestic production, pipeline imports, and LNG imports.

China's natural gas production has vast potential for growth. Recent estimates indicate that China holds about 4.7 trillion cubic meters (tcm) of proven natural gas reserves (US Energy Information Administration, 2015a). In comparison, it is estimated that proven US natural gas reserves are about 11.2 tcm (US Energy Information Administration, 2015b). The biggest potential in China is with respect to unconventional gas sources, shale gas in particular. The International Energy Agency estimates China's total technically recoverable unconventional gas resources to be 43.8 tcm, with the biggest contribution coming from shale gas (International Energy Agency, 2015b). Table 6 provides an overview of technically recoverable gas resources in China and selected regions.

Table 6: Technically recoverable unconventional gas resource in China and selected regions

tcm	Tight Gas	Shale Gas	Coalbed methane
China	3	31.6	9.2
OECD Americas	11	49	7
OECD Asia	8	13	8
Non-OECD Asia	13	40	13
World	81	213	50

Data from International Energy Agency (2015), World Energy Outlook

Although China's unconventional gas resources are substantial, there are considerable uncertainties about the pace of their development. The most significant shale gas field is in the early stages of development and faces various challenges, including complex geology, technical and water resource challenges, and regulatory hurdles. The prevailing view in the literature is that geological and industrial conditions are considerably less favourable in China than in North America, so significant commercial production is projected to be some years in the future. Recently, the Government cut its 2020 production target, which it set in 2012, by over half, from 60-100 bcma to 30 bcma (International Energy Agency, 2015a).

One of the biggest obstacles for commercialization of the shale gas resources is the availability of large amounts of water required for hydraulic fracturing, a scarce resource in Chinese shale gas basins (Che & Kompas, 2014a; International Energy Agency, 2014d). However, new methods for "fracking" that require little or no water have already been developed (National Geographic, 2015). Such technologies, currently pioneered by a number of companies, could have a significant impact on the long-term prospect of the Chinese shale gas industry.

Significant factors that could impede domestic production in China are related to regulatory or market conditions such as mineral rights, market price reform, and the industry organization and business culture (China Energy Fund Committee (CEFC), 2013). The Chinese government continues to emphasize the importance of domestic natural gas supply, and it is engaged in a strong push to develop these resources. To this end, the Government has initiated a number of reforms which aim to provide a positive impact on domestic natural gas production, while opening the sector to foreign investors who can bring the necessary technical expertise. Development of unconventional gas supply, primarily from coal-bed methane and shale gas, already has attracted greater interest from private investors, and private Chinese companies are involved in owning and exploring these resources. While currently experiencing delays, these present difficulties are unlikely to prevent China from advancing its development of shale gas over the next 5-10 years (Mitrova, 2014).

Expansion of unconventional gas production in China has implications for the international gas trade in the region as the prospects for growth of domestic production decrease the attractiveness of the long-term (and likely higher-priced) import options for Chinese buyers. In addition, increased volumes of domestically produced gas will improve China's negotiating position with its potential suppliers. At the same time, China is diversifying its import supply portfolio which, at present, includes pipeline gas from Central Asia, Myanmar, and Russia, as well as LNG-delivered gas to the Eastern seaboard (Figure 11). Each of these supply sources, domestic and foreign, has uncertainties in terms of security of supply, import volumes, and likely market prices.

Figure 11: Chinese gas import options

Adapted from Henderson (2011), The Pricing Debate over Russian Gas Exports to China

Pipeline Import Options

The current portfolio of pipeline gas imports to China includes the three Central Asian countries, Turkmenistan, Uzbekistan and Kazakhstan, and Myanmar, with anticipated future imports coming from Russia. Table 7 presents estimates of proven natural gas reserves in countries that export pipeline gas to China compared to the United States estimated reserves.

Table 7: Natural gas total proven reserves of selected countries

tcm	At end 2004	At end 2014
Kazakhstan	3	31.6
Myanmar	0.5	0.3
Russia	11	49
Turkmenistan	8	13
Uzbekistan	13	40
U.S.	81	213

Data from BP (2015), Statistical Review of World Energy

Pipeline imports to China from Central Asia began in December 2009 when the first gas supply from Turkmenistan arrived via the 1,833 km Central Asia–China pipeline that crosses Uzbekistan and Kazakhstan into China's western province of Xinjiang. At present, Turkmenistan is delivering 25 bcma, with supplies expected to reach 65 bcma by 2020.

China and Uzbekistan signed a framework agreement in June 2010 to deliver 10 bcma of natural gas. Kazakhstan has also agreed to supply 10 bcma. However, both countries face domestic demand and production issues, which means that the current trade levels of around 3 bcma and 0.1 bcma respectively may not increase in the foreseeable future (Henderson, 2014). If Kazakhstan and Uzbekistan reach their agreed supply commitments, total Central Asian pipeline import capacity could reach 85 bcma by 2020.

China's pipeline supply diversity is enhanced in the south through its over 2,000 km long pipeline connection with Myanmar, of which 793 km is located in Myanmar and 1,727 km in China. Construction of the pipeline began in June 2010, and finished in 2013. Myanmar started supply in 2013 with the expectation of delivering 2.5 bcma by the end of 2014 (Y. Chen, 2013). The full capacity of 12 bcma of supply is yet to be reached.

All of the supply sources noted previously have uncertainties. For example, Turkmenistan has signed multiple export agreements with other countries, raising the concern of whether it will have sufficient gas reserves to supply China in the future (China Energy Fund Committee (CEFC), 2013). The expected supply of 10 bcma from Uzbekistan also looks challenging considering its growing domestic demand (International Energy Agency, 2015a). With respect to Myanmar, there are concerns that the pipeline could become a target for the Myanmar opposition forces, which might disrupt the supply of gas to China (China Energy Fund Committee (CEFC), 2013; Henderson, 2014).

After ten years of negotiations, in May 2014, Russia and China signed an agreement for a "Power of Siberia" pipeline project to deliver natural gas from Siberia to China via an eastern route. The first quantities of gas could arrive in late 2019, and the (full-capacity) agreed volume of 38 bcma represents almost 1.5 times the current total LNG imports to China (International Energy Agency, 2014d). The approximately 3500 km pipeline would stretch from East Siberia to the Pacific Coast, with a spur carrying 38 bcma of gas into Northeast China. The remainder of the gas is split between the eastern Russia domestic market and a 14-21 bcma LNG facility planned to be built at Vladivostok (Henderson, 2014). The full commercial details of the agreement are not disclosed, but analysts assess the price to be between $ 9.78 – 10.61 (2015$ 9.80 – 10.64) per MMBtu (US China Economic And Security Review Commission, 2014). This agreement sets a new price benchmark, as the relatively low price of this supply challenges potential LNG exporters, putting them under pressure to cut their costs of production or fail to penetrate the market (International Energy Agency, 2014d).

Not long after the first pipeline agreement, China and Russia took steps toward agreeing on a second pipeline supply, this time via the "western route", the so-called Altai pipeline. In November 2014, the two countries signed a Memorandum of Understanding for 30 bcma of gas (full capacity delivery). Russia's rationale for exporting gas to western China has been to reduce its trade dependence on Europe (Henderson, 2014). It is likely that negotiations on the Altai pipeline will not take 10 years, as with the previous pipeline. However, it is not probable that the project will commence until 2020, or the first deliveries take place before 2025. The biggest obstacle might be China's unwillingness to lock itself into another big purchasing commitment with Russia (International Energy Agency, 2015a).

LNG Supply Options

Around the end of the 2010s and the beginning of the 2020s, several LNG export projects, targeting the East Asian market, plan to commence operations and bring supply from a number of different sources, notably Australia, East Africa (Mozambique and Tanzania), Russia, and North America (US and Canada). Which projects, and how many of them, will go ahead is uncertain; also questionable is a realistic timescale for the expected supply to the East Asian countries. Below, I provide more information about these projects. BC LNG supply volumes is not an object of my analysis, consequently, I have not provided detailed information on BC LNG projects.

Australian LNG Supply

Since 2000, Australia has played an important role as an LNG exporter for East Asian countries. Australia's total proven natural gas reserves are estimated to be 3.7 tcm in 2014 (BP, 2015), and the country is currently the fastest-growing LNG producer in the world. Australia already has three LNG projects with a total export capacity of over

33 bcma: The North-West Shelf with 22.5 bcma, Darwin LNG with 4.8 bcma and Pluto LNG with 6 bcma. An additional seven projects are under construction, which will add another 85 bcma (Table 8).

Table 8: Australia LNG projects under construction

	bcma	Total Capacity
1	Gorgon (3 trains)	21.5
2	Wheatstone (2 trains)	12.2
3	Prelude	4.9
4	Ichthy (2 trains)	11.6
5	QCLNG (2 trains)	11.7
6	GLNG (2 trains)	10.7
7	Asia-Pacific LNG (2 trains)	12.4
	TOTAL	85

Data from Ledesma, Henderson, & Palmer, 2014

The new LNG projects are scheduled to start operations in the second half of this decade, resulting in an aggregate of 117 bcma LNG liquefaction capacity (Ledesma, Henderson, & Palmer, 2014). Prior to the development of the wave of new LNG projects in Australia, no country had experienced seven LNG projects under construction at the same time. This rapid expansion of the LNG industry has led to labor shortages, delays in project completion and cost escalations. This increased construction costs of Australian LNG projects could impair their competitiveness in the East Asian market.

USA LNG Supply

The rapid development of shale gas production in North America has caused Henry Hub gas prices to fall to historically low levels and has created opportunities for substantial North American LNG exports. As recently as 2004, the US appeared set to become a major LNG importer, but by 2011 it had become self-sufficient in natural gas, with the prospect of significant LNG exports and the potential to significantly impact the global gas market (Henderson, 2012).

US LNG facilities for export are brownfield investments, based on converting LNG import terminals, and other receiving infrastructure (storage, transport and port facilities) into exporting facilities. Brownfield projects are more competitive due to cost savings from reduced site preparation, use of existing storage tanks, and the existence of established facilities and utilities (power, water and other infrastructure). This improves the competitiveness of US LNG against more costly greenfield supply sources targeting the East Asian market.

Current US legislation requires a license from the US Department of Energy (DOE) in order to export LNG. Exports to “free trade agreement” (FTA) countries are automatically approved. At present, the US has FTAs with 20 countries, of which South Korea represents a market with the scale to absorb significant new LNG volumes (in excess of existing contracted supplies). In order to export LNG to China, Japan, and Taiwan, projects need to gain non-FTA approval. The DOE approval process is conditional upon an environmental assessment of the project by the Federal Energy Regulatory Commission (Rogers & Stern, 2014). Up to May 2015, the Department of Energy (DOE) had received 54 LNG export applications for close to 480 bcma of LNG export capacity (Office of Fossil Energy, 2015, International Energy Agency, 2015). Of these, ten projects equal to 130 bcma have received authorization to export to non-FTA countries (International Energy Agency, 2015a).

The emergence of the US as a source of LNG trade is an important factor in the East Asian supply and demand picture, as the anticipation of a new gas supply with hub-based pricing provides an impetus for change in the natural gas market dynamics in East Asia. Nevertheless, there are also ambiguities about this supply option to East Asia, in particular with respect to the potential quantities of LNG for export, given the concerns of some US politicians about the effect of exports on domestic gas prices. The Department of Energy recently concluded, however, that the likely impact on the US domestic gas price of an increase in the total export allowance to 207 bcma would be marginal (Deutsche Bank, 2014). Consequently, it is possible that US authorities will consider significantly larger export volumes than 124 bcma, which, prior to the Department of Energy conclusions, had been considered the likely export ceiling level.

Russian LNG Supply

Russia has vast gas resources in its eastern regions, which include fields in the Siberian and Far East Federal Districts, as well as prospective fields offshore in the Arctic Ocean (Henderson & Pirani, 2014). The only current Russian gas exports to East Asia are in the form of LNG from the Sakhalin 2 project, which commenced operations in 2009. However, the supply picture of Russian gas in East Asia is set to change materially in the coming years. In addition to the state-owned Gazprom, two other Russian companies, Novatek and Rosneft, form the driving force of Russia's expansion into the East Asian gas market, which was enabled by a December 2013 decision by the Russian government to liberalize LNG exports and end Gazprom's monopoly in this sector. If all the projects under construction or consideration are realized, Russia's LNG export capacity will significantly increase. However, the quantities and timing of this supply are uncertain given the harsh climate, lack of infrastructure, and financial and technical challenges facing the developers, especially with the sanctions imposed on Russia by Western countries because of the conflict in Ukraine.

Gazprom plans to increase supply to East Asia involve two projects: expansion of Sakhalin 2 LNG and a new facility in Vladivostok. *Sakhalin 2 LNG* is currently in operation and exports almost 14 bcma of gas to East Asia, mainly to Japan and South Korea. There is a plan to extend the existing project and upgrade it to 21 bcma capacity. *Vladivostok LNG*, on the other hand, is still in the planning stage. In 2013, Gazprom and a consortium of five Japanese companies signed a Memorandum of Understanding for this project with a planned capacity of 6.8 bcma. However, so far it has failed to secure commitments from buyers and support from foreign partners, which are preconditions for the project to move on with development (International Energy Agency, 2015a).

Rosneft's *Sakhalin 1 (Far East)* project, with 8 bcma of production capacity, is already under construction. However, the project could be at risk; Rosneft indicated in

May 2015 that it may have to move the facility off Sakhalin Island because Gazprom (which operates the nearby Sakhalin 2 LNG export terminal), is denying access to the pipeline to bring the gas to tidewater in order to export it (Centre for Strategic and International Studies, 2015). At the very least, it is likely that the first deliveries of Sakhalin 1 LNG will be delayed until 2020 (Reuters, 2015).

Novatek's *Yamal LNG* project started construction in 2013. The total expected capacity is 23 bcma, with the project expected to produce 7.5 bcma by late 2017 or early 2018. Yamal LNG is located above the Arctic Circle, a region that is ice-bound for seven to nine months during the year, limiting transport of LNG from the facility to the East Asian market. Consequently, it is likely that only half of the projected output will reach East Asian buyers each year (Henderson & Stern, 2014).

East Africa LNG Projects

The recent discoveries of conventional natural gas off the coast of Mozambique and Tanzania have attracted significant attention, and the two countries could become the largest African exporters with possible total recoverable gas reserves of 3.9 tcm in Mozambique and 1 tcm in Tanzania (International Energy Agency, 2014a). Proximity to the East Asian market makes East African countries strong competitors with other LNG projects also targeting that market. However, while Tanzania and Mozambique have sizeable resources, the capacity to develop large projects may be a challenge — both countries are economically undeveloped, and have limited infrastructure to support extensive resource development (International Energy Agency, 2014d).

Mozambique is likely to be the first country to export LNG from East Africa after 2020, due to its favourable domestic gas policy regarding exporting LNG . The liquefaction plant that is currently under construction will have an initial capacity of 28 bcma and increase up to 70 bcma. The expectation that the LNG supply coming from East Africa will apply elements of Henry Hub pricing in order to attract East Asian buyers was confirmed when it was announced that the LNG developer had signed initial agreements with buyers based on a hybrid pricing formula (International Energy Agency, 2014d; The Economist, 2014). The hybrid pricing contract structure comprises both hub and oil pricing formulas. In this case, buyers and seller agree on the percentage of oil- and hub-indexed price on top of agreeing on the details (slopes and constants) for both formulas (International Energy Agency, 2014a; 2014d).

Tanzania also aims to be a new LNG exporter. Its first LNG project is still in the planning stage and is designed for approximately 14 bcma of capacity, with a possibility for extension of up to 21 bcma (Credit Suisse, 2014). Unlike Mozambique, Tanzania's domestic policy may be a hindrance for LNG development. The Government approved the "Natural Gas Policy of Tanzania 2013" which states that the domestic market has a priority over the export market. However, a potential disruption of gas exports in favour of the domestic market may not support potential investors' interest in the country. A further disadvantage is that Tanzania is completely new to the LNG business, and there is virtually no infrastructure available to support the initial development (International Energy Agency, 2014d).

4.4. JCC Indexation and the "Asian Premium"

As noted, much of the recent interest in LNG development and export stems from exploiting the substantial discrepancies between prices in East Asian, European and North American markets. In early 2012, internationally traded gas prices were at the "historical disequilibrium", the Japanese LNG price (ex ship, as liquid) was over 6 times higher than the US Henry Hub price (Jensen, 2013). The gap between East Asian and US spot prices has narrowed since 2013. As more supply arrives to this market, there will be a tendency for further reduction of the premium. The most recent decrease of the gap between Asian and US gas prices was not the result of any fundamental change in the method of price determination, but rather by the decrease in oil prices, pushing oil-indexed contract prices downward.

A price differential between the regional markets may result from different transport costs. East Asia is geographically distant from natural gas exporting countries, and thus, bears higher transportation costs for the imported gas. Another reason may be because the East Asian natural gas market has mainly been a "seller's market", with greater demand than supply. Nonetheless, it is the historical pricing mechanism — oil-indexation — which is being increasingly scrutinized, with a growing concern that this mechanism no longer provides an appropriate indication of actual market conditions (Che & Kompas, 2014b). The JCC indexation worked for many decades, but the rationale for it began to weaken when crude oil stopped being LNG's main competitor for electricity generation and industrial use.

A study by Miyamoto (2009) analyzing JCC LNG and oil prices, developed a "netback market value" methodology for LNG pricing in the main Asian importing markets. The aim of this study was to examine the weighted average cost of fuels competing with gas and to compare this value with the JCC LNG import prices at various oil price levels. The results of the research suggest that oil indexation becomes more questionable for most East Asian countries at oil prices above US$ 40/bbl since, at this level, the JCC price exceeds the average netback market value for LNG. At $90/bbl, the difference becomes very substantial for most countries (Miyamoto, 2009).

Che and Kompas (2014) conducted a study of LNG pricing in the Asia-Pacific region over the period of 1989–2014, with supporting econometric analysis to analyze the structure and dynamics of LNG pricing in the Asian market. The authors note that since 2003, the divergence between LNG prices and crude oil prices based on an energy-equivalent basis has been getting larger, indicating that the role of the B constant in the formula (non-oil linked factors in LNG price) is increasing. The results of the study show that the share of this part of LNG price increased from less than 50% prior to 2008 to about 70% post 2008, suggesting an increase in the contribution of 'other factors' to

LNG price formation, such as changes in LNG demand and supply as a consequence of geopolitical and economical influences.

As natural gas becomes a widely traded commodity, oil-indexation is coming under increasing pressure from East Asian buyers who are looking for changes that reflect the market's supply-demand balance. A transition is ongoing in the European gas market, resulting in the emergence of contracts tied to gas spot prices on the European hubs, or negotiated reductions of the base price in some of the existing oil-indexed contracts (Rogers & Stern, 2014). Changes in the pricing mechanism in the East Asian market may follow a similar path, despite notable differences between the two regions. The main differences are: i) Europe is a mature market with diversified pipelines, LNG supply options and extensive inter-regional connectedness, and ii) Europe had functioning gas trading hubs before the start of the transition. In contrast, the East Asian market does not have trading hubs, and it is expected that it will take several decades before a hub is operational and in a position to provide a viable price reference point.

LNG projects require large up-front investments. Because of this, security of demand is an important consideration for LNG investors. In this respect, a crucial question is whether more competitive markets, including those in which prices are set by gas-to-gas competition, can provide sufficient security for new large-scale investments in gas infrastructure (International Energy Agency, 2014d). The view that an LNG project requires an oil-linked pricing mechanism to gain financial support from project lenders seems broadly accepted for LNG projects in the Pacific Basin, or at least it was until oil prices collapsed in 2014. This was also one of the arguments for maintaining oil-indexation in the European market as the obligatory framework for the needed investment. However, the latest infrastructure development to bring Caspian gas to Europe (Shah Deniz Phase 2 project) is a large-scale greenfield development implemented after the start of the transition in the European market, and while some of the sales contracts for the supply from this pipeline are oil-linked, there are also contracts priced off of European gas trading hubs. Reportedly, this BP-lead development offered long-term contracts with ties to prices on domestic hubs in an effort to win market share from rival suppliers in Russia and Algeria (Argus Media, 2013; Reuters, 2014).

If the existence of contracts with different pricing mechanisms (than oil-linked) is an indication of the transition process, then it is possible to say that such a transition in the East Asian market may have already commenced. United States LNG exporters have departed from traditional oil-linked long-term contracts with final destination clauses — contractual instruments to prevent buyers from reselling gas to another country. Instead, they offer Henry Hub-based long-term contracts with no destination clauses, which allows the gas to be sold wherever the buyer wishes (International Energy Agency, 2014b). For LNG exported from North America to East Asia, LNG prices at the destination will be the “Henry Hub plus” price, which includes Henry Hub spot prices, costs of liquefaction, delivery and other relevant costs (Che & Kompas, 2014b). In addition to gas-on-gas priced LNG coming from the US, Andarenko (the LNG supplier from Mozambique) announced that they have signed supply contracts with Asian buyers that include a hybrid pricing formula based on both international oil prices and US natural gas prices (The Economist, 2014).

The emergence of LNG contracts based on Henry Hub prices is significant, since, for the first time, East Asian buyers have a choice between traditional oil-indexed LNG contracts and contracts with prices based on gas-on-gas competition. This provides a degree of price competition which was lacking in the market (Stern, 2014). While the emergence of gas-on-gas priced contracts is expected to affect LNG contract pricing in East Asia, it should not be understood as an assurance of lower prices, since price formation should not be confused with price levels. For example, higher Henry Hub prices at around $5/ MMBtu and oil prices at around $80/bbl would deliver gas prices comparable to (and possibly higher than) gas prices determined under the traditional JCC mechanism (Stern, 2014).

LNG buyers in the East Asian market see the traditional oil-indexation price mechanism as a problem. A simple solution could be to reduce the slopes (link to oil price) in the formulae in order to reduce prices, but this would not resolve the fundamental problem that prices are unlikely to reflect future gas supply and demand market conditions in East Asia (Stern, 2014). However, while the historic pricing mechanism may no longer be appropriate, the transition to a mechanism based on supply and demand fundamentals of the East Asian gas market may take time. Such a transition has been under way in Europe for several years now and is still not close to completion.

5. RESULTS AND DISCUSSION

I create scenarios for each country as the culmination of my research on past gas demand patterns, the key demand factors, current and future policies, economics, and other events which may impact future gas demand for the period 2016 to 2040. For China, an additional step is required, which is to estimate the likely quantity of domestic natural gas production and its impact on future import demand. I constructed "baseline" and "high growth" demand scenarios for all four countries and estimated ranges of the total demand for the East Asia region. For China, I created baseline and high growth domestic production cases as well.

I do not present an analysis of a "low" demand scenario because a relatively slow natural gas demand growth in East Asia has limited prospects for BC LNG exports. There are many alternative, competitive supply options to meet that demand, including domestic production of conventional and unconventional gas, pipelines from other countries, and low-cost LNG suppliers. I therefore focus my efforts on presenting two scenarios. The first I refer to as my base scenario, which is what I consider to be the most likely. The second scenario examines less likely, but nonetheless plausible, conditions under which demand would exceed the baseline case. This enables me to consider the extent to which higher demand in China especially would lead to dramatically larger imports of gas, possibly including much greater LNG imports. I also address various constraints and uncertainties about supply sources. Finally, I estimate likely production costs of the various gas supply options. From this cost consideration, I estimate likely market prices for prospective LNG suppliers to the East Asian market, including potential BC LNG suppliers.

5.1. East Asian Market Demand Projections

To estimate the relevant demand volumes for the four East Asian countries, I apply projected growth rates to 2012 natural gas consumption figures, as reported by the International Energy Agency in the Natural Gas Information Report, 2014 edition. I develop these growth rates from reports and analyses provided by energy sector modelers, the financial industry, and other researchers addressing the long-term outlook for natural gas demand and the East Asia market (e.g. International Energy Agency, The Oxford Institute for Energy Studies, Credit Suisse Securities Research & Analytics, The Asia-Pacific Energy Research Centre - APERC). I note key underlying forecast assumptions as these reveal what the researchers consider to be the most important drivers of the long-term demand for natural gas. I complement this information with research on the economic, technological, geopolitical, and environmental factors that, in the long-term, could affect natural gas demand (and China's domestic production) for East Asian countries (i.e. new technologies affecting unconventional gas production, global actions to address climate change). I then consider all gathered information and develop a set of assumptions and projection growth rates for my scenarios.

The availability of other long-term market forecasts varies, with China's market attracting the attention of many researchers, but with only a limited set of projections for the other three countries. In the case of China, I compared a number of assessments of long-term demand growth rates. The International Energy Agency (IEA) provides an annual report (World Energy Outlook) with its projections for the global energy sector, including the natural gas demand growth for China. I derive an estimate using the IEA and other available forecasts (provided by the Oxford Institute for Energy Studies, and the Asia-Pacific Energy Research Centre). To calculate the baseline domestic production numbers, I follow the growth rate projection assumed by the IEA in their 2014 WEO Report. For my high growth case, I consider IEA's "The Golden Rules for the Golden Age of Gas" report (2012) as well as assessment by the Oxford Institute for Energy Studies, and derive an estimate that reflects my assumption that China's shale gas production will not be constrained by water shortages.

For Japan's baseline case, I follow the growth rate projected by the International Energy Agency (2014). For South Korea, I use the government's natural gas demand growth rate target. To derive their high growth forecasts, I use projections provided by APERC for guidance. As the IEA does not provide projections for demand growth in Taiwan, I was guided by forecasts provided by APERC (2013) and Credit Suisse (2014) for both the baseline and high growth rates.

My projections for natural gas demand in East Asia indicate that demand will continue to grow from 2016 to 2040. The most significant contribution to the region's demand is that of China, which grows at an average annual rate of 6% in the baseline scenario and 7% in the high-growth scenario. In contrast, demand in Japan declines at an annual rate of 0.8% in the baseline scenario and grows by 0.6% annually in the high growth scenario. Taiwan's and South Korea's demand growth fall in between, with Taiwan's baseline and high growth rates at 2% and 3% respectively, and South Korea's at 1.7% and 2.2% (Figure 12). By 2040, China's projected demand growth for the baseline scenario results in a five-fold increase in volume, with much more modest increases in demand volumes for the other three countries (Table 9). Total East Asian projected baseline and high demand figures, presented in (Figure 13), are calculated by summing up the individual countries' respective baseline and high demand volumes. The aggregate baseline volume of natural gas demand in 2040 is almost three times greater than demand in 2012 and reaches 950 bcma.

Figure 12: Forecasted East Asia natural gas demand (baseline growth rates)

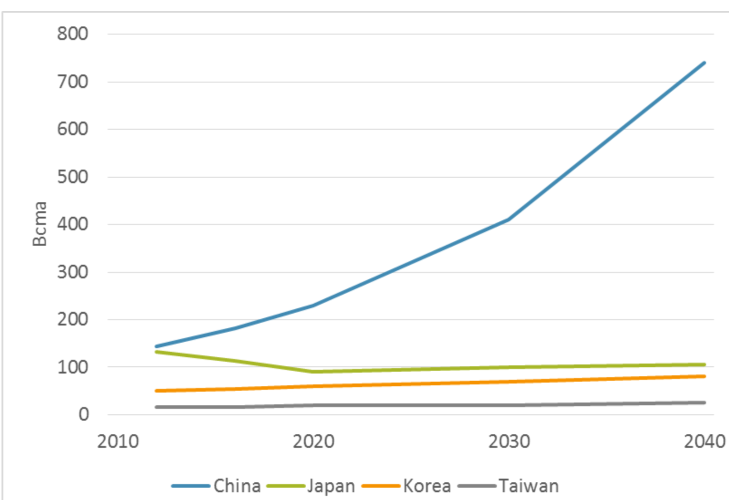
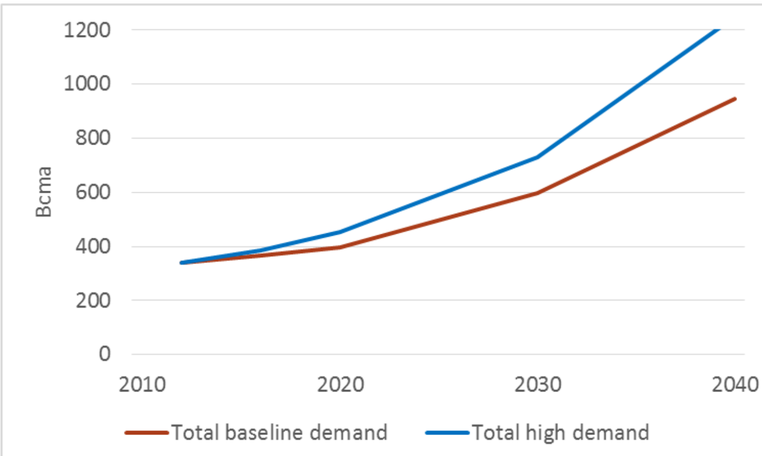


Table 9: Forecast of East Asia natural gas demand

	2012	2016		2020		2030		2040	
(bcma)	(Actual)	Baseline	High	Baseline	High	Baseline	High	Baseline	High
China	**144**	**182**	**189**	230	250	410	490	740	960
Japan	132	113	124	90	130	100	145	105	155
Korea	50	54	55	60	60	70	75	80	105
Taiwan	15	16	17	20	20	20	25	25	35
TOTAL	341	365	385	400	460	600	735	950	1255

Figure 13: Forecasted East Asia natural gas demand

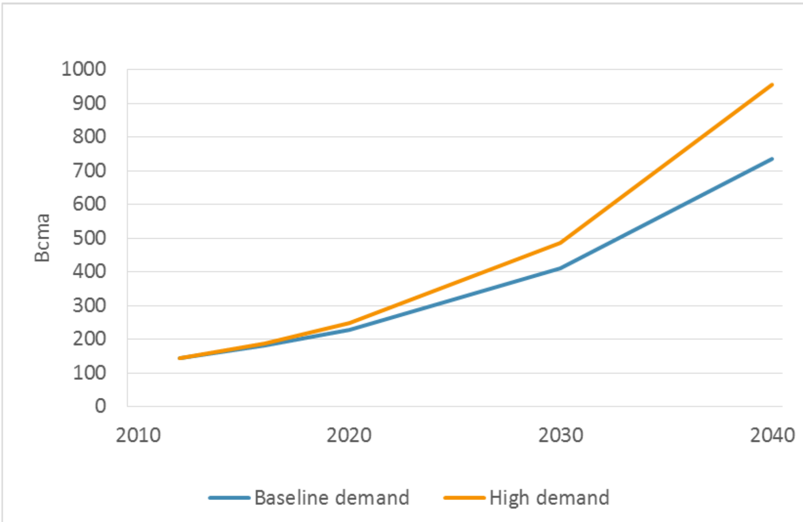


China's Natural Gas Demand and Domestic Production

China's demand grows from 144 bcma in 2012 to between 740 and 960 bcma by 2040. The underlying assumption for both cases is that energy demand growth slows down, driven by a slowdown in the rate of GDP growth, the restructuring of the economy to less energy-intensive industries, and efforts to improve energy efficiency.

The biggest demand increase in both scenarios occurs after 2020 (Figure 14). Electricity generation is the main driver of demand growth in the baseline scenario (International Energy Agency, 2013). The implementation of environmental policies to address local pollution and fulfill international obligations to reduce GHG emissions leads to an increase in natural gas consumption for electricity generation and a decrease in the use of coal. As a result, coal demand peaks by 2030, which is in accordance with the Chinese government's climate commitment.

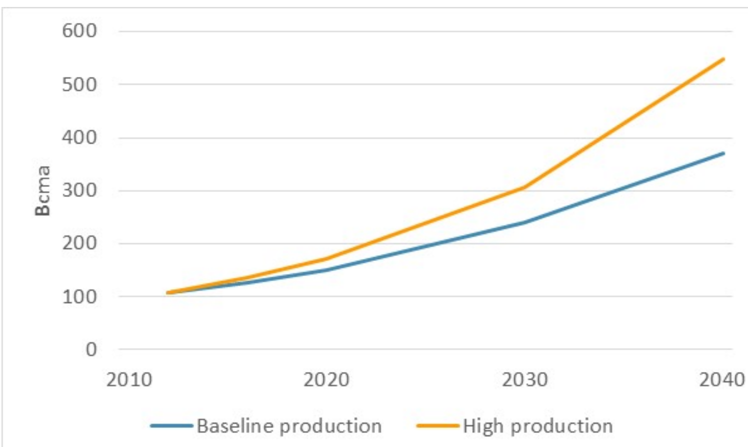
Figure 14: Forecasted China natural gas demand



In the high growth scenario, additional growth is facilitated by the implementation of even more stringent environmental policies as China contributes to global efforts to address climate change. This has the effect of controlling coal consumption, phasing out obsolete industrial capacity, and increasing clean-energy supplies. In the high-demand case, electricity price reform follows the changes that have already been implemented in natural gas pricing in order to stimulate the increased use of natural gas in the power generation sector. It is assumed that the Chinese government implements an integrated electricity pricing system that reflects the operating costs of plants using different fuels so that gas-fired power plants can generate a profit. Further, the high-growth scenario assumes that a stringent, centrally administered carbon pricing mechanism is implemented to reflect the environmental impacts of coal. Consequently, by 2040, new gas generation facilities replace 50% of the current coal generation capacity. The use of coal peaks by 2020, earlier than assumed in the baseline case.

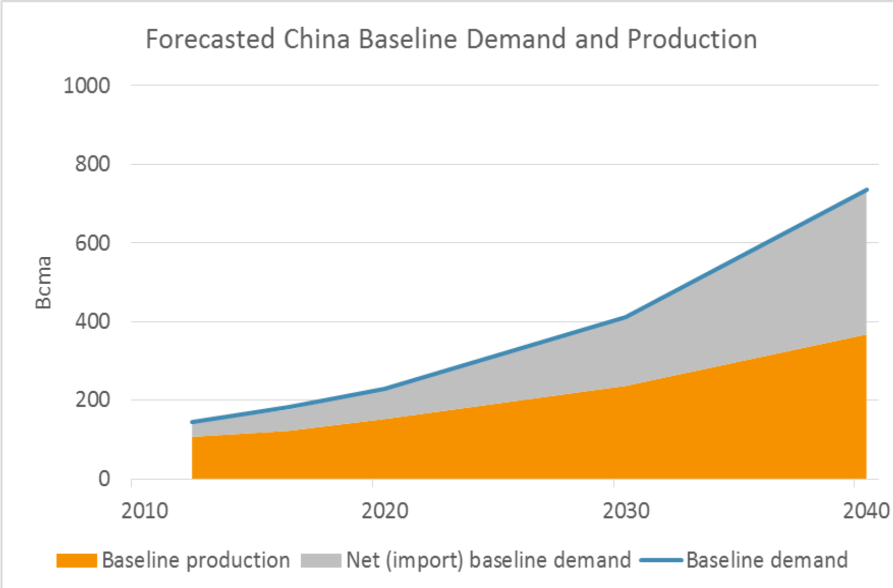
I associate the high demand scenario in China with higher domestic gas production. In the baseline case, China's domestic production grows at an annual rate of 4.5; in the high demand scenario it grows at 6%. In my high production projections, I no longer assume water constraints as I anticipate production technologies that require reduced water to become available to the Chinese shale gas industry. In addition, the growing level of expertise in shale gas production technologies and techniques continues to help China develop its shale gas resources. Thus, the high demand scenario has domestic gas production of 550 bcma by 2040, as opposed to 370 bcma in the baseline scenario (Figure 15).

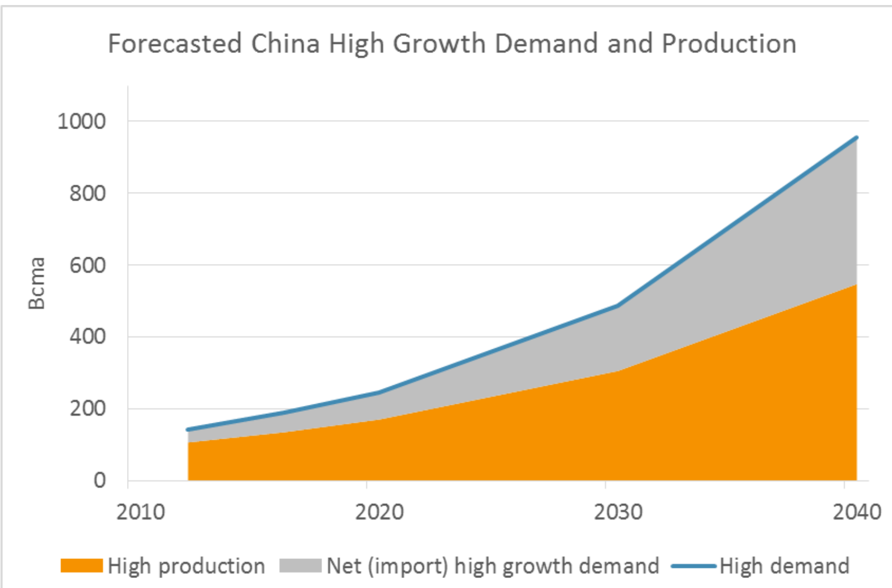
Figure 15: China domestic natural gas production – baseline and high production case



The high demand growth scenario does not lead to significantly larger import requirements. In the high growth / high domestic production case, the net demand, or the difference between volumes of total natural gas demanded and domestic production (i.e. portion of demand that could be satisfied by imported gas) is only slightly larger due to increased domestic production. In the baseline case, domestic production provides 50% of natural gas demand, compared to 57% of demand in the high-growth case (Figure 16).

Figure 16: China gas demand and domestic production – baseline and high growth case

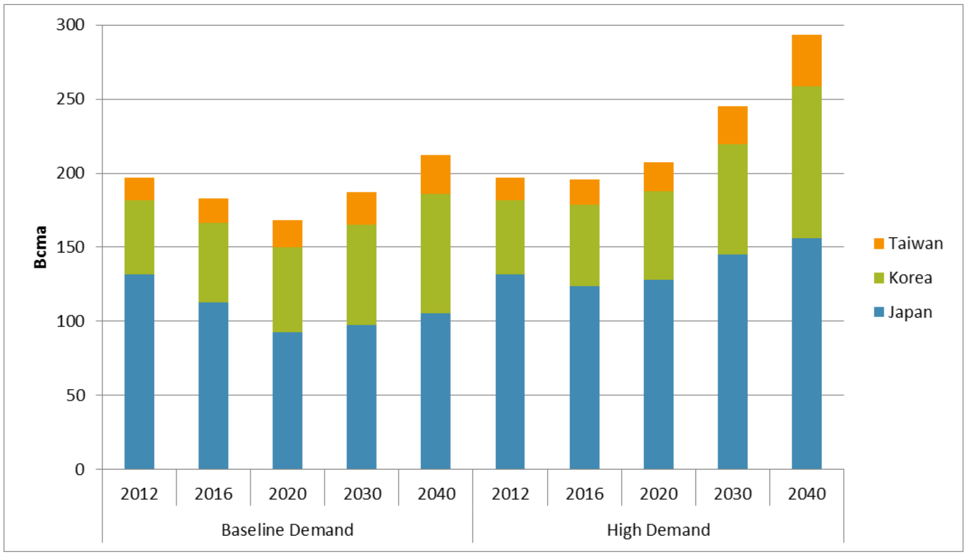




<u>Japan, South Korea, and Taiwan Demand</u>

Projected natural gas requirements in Japan, South Korea, and Taiwan (Figure 17) have lesser impacts on total demand for the East Asia region than that of China. The main uncertainty for natural gas demand growth in these three countries relates to the future of nuclear energy, as it could satisfy a significant amount of energy demand.

Figure 17: Forecasted Japan, South Korea, Taiwan demand



*Japan's demand f*or natural gas in the baseline case follows the International Energy Agency's growth rate projection, decreasing at a rate of 0.8% per annum (International Energy Agency, 2014d). The lower demand growth rate is a result of the gradual re-start of currently idle nuclear plants and increased efforts for energy conservation and expansion of renewables. Japan's gas demand initially decreases at a higher rate, following the re-introduction of nuclear facilities, then increases to reach 105 bcma by 2040.

In the high growth scenario, demand grows at an average rate of 0.6% pre annum. Demand also decreases initially, due to the restart of the nuclear plants, flattens out post 2020, and then increases to 155 bcma by 2040. The key factor influencing demand in the high-growth scenario is the implementation of stringent climate change policies. These policies and actions are related to global efforts aimed at the reduction of GHG emissions. The high-growth scenario assumes that Japan participates in global climate efforts and eliminates all coal-fired power generation facilities by 2040, which leads to increased demand for natural gas.

South Korea's demand grows at a rate of 1.7% per annum in the baseline case, which corresponds to the Government's target growth rate and results in a demand volume of 80 bcma by 2040. In the high-growth case, the assumed rate of increase is 2.2%, and the natural gas demand volume in 2040 rises to 105 bcma. In both scenarios, implementation of the Government's plans to reduce energy intensity to the OECD average reduces natural gas demand. Despite reduced targets for nuclear energy's share of the installed capacity, in the baseline case there is still an expansion in the use of nuclear energy. South Korea also moves ahead with the expansion of coal-fired baseload power generation.

In the high growth scenario, South Korea implements stringent environmental policies to address climate change, which lead to the elimination of coal from its power mix by 2040 and its replacement with natural gas. Nuclear power is projected not to increase due to public opposition.

Taiwan's demand grows between 2% per annum in the baseline and 3% annually in the high-growth demand case. The growth rate in both cases reflects Taiwan's transformation into a high technology and service-oriented economy, as well as the implementation of policies and actions necessary to meet the Government's energy conservation and efficiency targets. Those activities yield substantial reductions in total energy demand, including that of natural gas.

Similar to Japan and South Korea, the main uncertainty regarding natural gas demand in Taiwan is the future of nuclear power. In the baseline case, the country continues its reliance on nuclear energy and coal for power generation. The lifespan of existing nuclear facilities is extended, or the facilities are replaced at the time of their retirement. The fourth nuclear plant, currently halted due to public opposition, begins operation. In the high demand case, Taiwan's nuclear energy use decreases: existing plants are retired and there is no development of additional capacity. The Taiwanese government, due to its ambiguous status in the international community and desire for international recognition of its sovereignty

(Woodrow Wilson International Center for Scholars, 2012), seeks ways to voluntarily adhere to global norms. In that context, the policies implemented follow global activities related to climate change and reduction of GHG emissions. Due to a decrease in the use of coal and nuclear power, demand for natural gas increases.

5.1. East Asia Supply Options

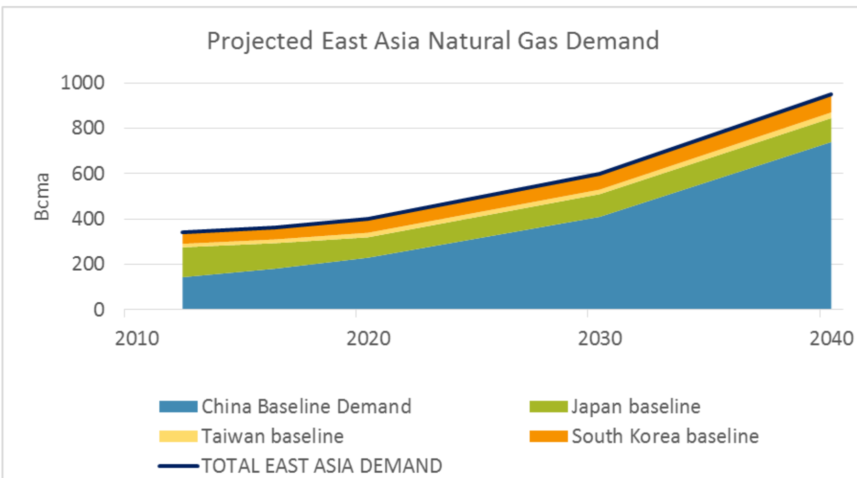
Given the projected natural gas production in China, anticipated forthcoming pipeline supply, and substantial LNG capacity coming online during the period from 2020 to 2040, there is likely going to be a substantial supply of gas from a diversity of sources available to the East Asian market. Of the four East Asian countries, China has a particularly wide range of choices when it comes to gas suppliers, including domestic production and various pipeline supply options, while the other three countries are essentially dependent on LNG imports.

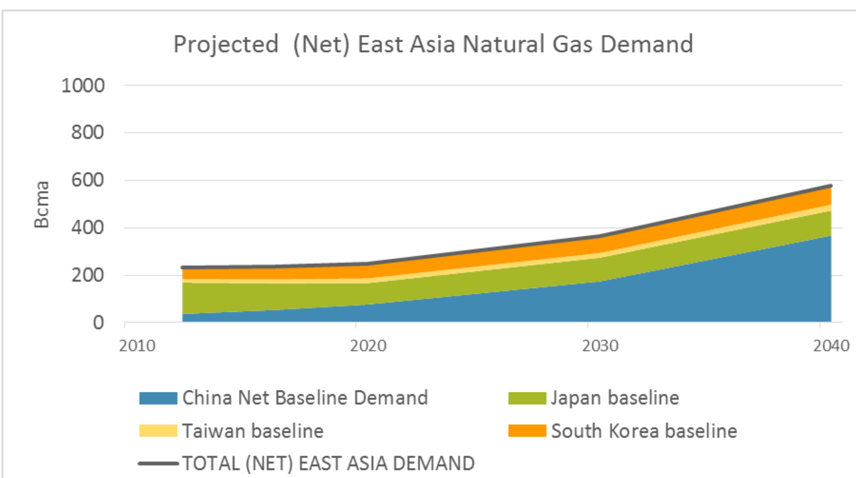
Domestic Production in China

Considering the projected domestic production in China, a large portion of demand in the East Asian market could be supplied from the region itself. To illustrate, the projected baseline volume of natural gas produced in China reaches 367 bcma in 2040 — almost twice the total baseline demand for Japan, South Korea and Taiwan (210 bcma).

The potential impact of China's domestic production on East Asia's natural gas demand is illustrated by comparing the two total demand figures for the region: one where aggregate demand is calculated with China's full demand and the other, which incorporates China's "net" demand volume. "Net" demand is the difference between China's total projected demand and projected domestically produced gas. Using "net" demand for China in the calculation of the aggregate regional gas demand implies that domestic production satisfies a portion of China's total natural gas needs. Adding either China's full or "net" demand to the projected baseline demand of the other three countries results in substantially different estimates for the aggregate East Asia Demand that could be satisfied by imported gas (Figure 18).

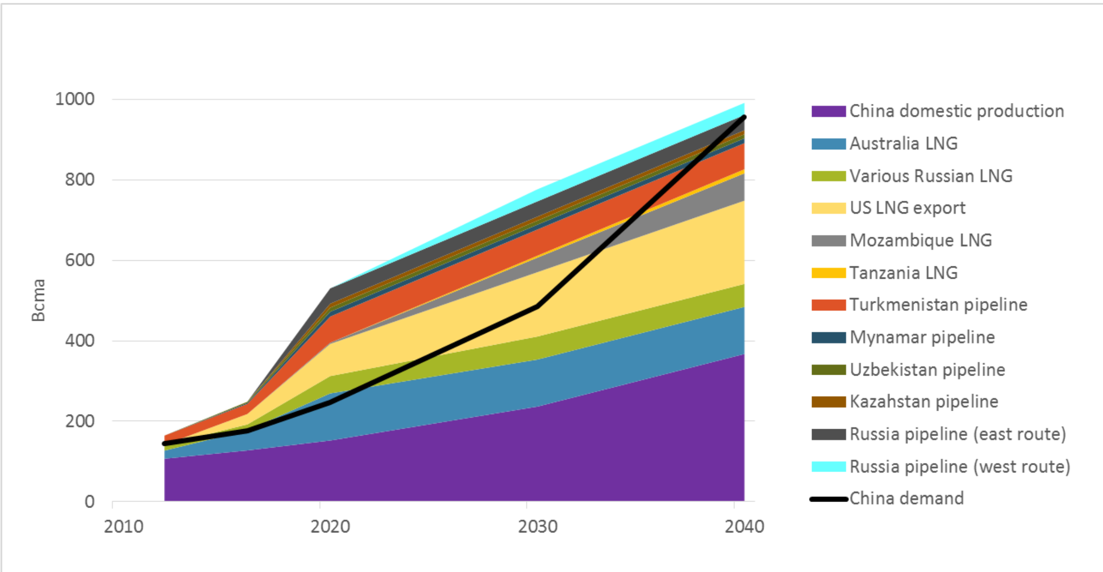
Figure 18: Projected East Asia natural gas demand – total and net of China domestic production





While China's domestic production may cover a large portion of the demand, additional quantities of imported gas are likely to find a market opportunity. Figure 19 compares China's projected baseline demand and the supply options competing to satisfy it. It shows that a large portion of demand could be satisfied by domestic production, but also illustrates a gap that may be closed by imported pipeline gas and/or LNG.

Figure 19: Chinese baseline demand and sources of supply



Pipeline Supply

China already receives some quantities of pipeline gas from Central Asian countries and Myanmar. However, it is likely that China will decide not to take Myanmar's supply at its full capacity, given the uncertainty of those deliveries due to possible disruptions on the Myanmar portion of the pipeline. China pipeline gas also includes supply from Turkmenistan and some quantities from Uzbekistan and Kazakhstan. Although Central Asian gas is more expensive, supply from Kazakhstan and Uzbekistan is flexible because it is the result of governmental, rather than formal, sales and purchase agreements. Therefore, China could adjust the import volumes of central Asian gas if more favourable supply options become available.

Such an opportunity may come from the second pipeline from Russia, the "Altai" pipeline, with a total capacity of 30 bcma. As noted earlier, Russia's strategic geo-political interest in the diversification of its natural gas market may facilitate reaching an agreement with China for the second pipeline within the next several years. It is likely that the supply will be very competitively priced and attractive to the Chinese buyers. Also, the Altai pipeline supply enables reduced dependency on Central Asian gas; this is of concern for China because multiple export agreements make deliveries from Turkmenistan uncertain. This second project, combined with a previously approved agreement, would mean a supply of 68 bcma from Russia — or 18% of total imports in 2040 in the baseline scenario. Therefore, future Russian pipeline supply could have a significant impact for LNG projects targeting China's market.

Table 10 presents China's gas demand "balance", considering the baseline growth volumes on the demand side, and the domestic production and available pipeline supply on the supply side. Table 11 presents the balance considering the same projections for demand. However, on the supply side, I reduce volumes of supply from Turkmenistan and Myanmar in order to account for the uncertainties related to these supply options. Specifically, as of 2030, I reduce anticipated supply from Myanmar by 50% (as of 2020) and supply from Turkmenistan by 20% (as of 2030). I perform these reductions to test what might be China's LNG import needs and discern what portion of the projected demand could still remain unmet (assuming domestic production and pipeline gas supply are initial supply choices). The result — remaining unmet demand — represents plausible Chinese LNG import.

Table 10: China gas demand and pipeline supply balance

	2012	2016	2020	2030	2040
China Baseline Demand	144	182	229	411	735
China Production	107	128	152	237	367
China Demand Net of Domestic Production	37	54	77	174	368
Turkmenistan pipeline supply	23	25	65	65	65
Myanmar pipeline supply		2.5	12	12	12
Uzbekistan pipeline supply		2.9	10	10	10
Kazakhstan pipeline supply		0.1	10	10	10
Russia east pipeline supply (Power of Siberia)			38	38	38
Russia west pipeline supply (Altai)				30	30
Total pipeline supply	23	31	135	165	165
Remaining demand		**23**	**-58**	**9**	**203**

Table 11: China gas demand and pipeline supply balance – adjusted for pipeline supply uncertainties

	2012	2016	2020	2030	2040
China Baseline Demand	144	182	229	411	735
China Production	107	128	152	237	367
China Demand Net of Domestic Production	37	54	77	174	368
Turkmenistan pipeline supply 80% of capacity	23	25	65	52	52
Myanmar pipeline supply 50% of capacity		2.5	6	6	6
Uzbekistan pipeline supply		2.9	10	10	10
Kazakhstan pipeline supply		0.1	10	10	10
Russia east pipeline supply (Power of Siberia)			38	38	38
Russia west pipeline supply (Altai)				30	30
Total pipeline supply	23	31	129	146	146
Remaining demand		**23**	**-52**	**28**	**222**

Pipeline gas is a supply option only for China, since the other three countries at present do not have any tangible pipeline supply choices. However, this might change in the future for Japan and South Korea, as both countries' geographical location allows for pipeline supply from Russia. Moreover, such possibilities have already been contemplated by both countries and their potential suppliers.

Reportedly, Russia made a proposal in November 2014 to link Sakhalin with Japan's northern Hokkaido Island (Centre for Strategic and International Studies, 2015).

Japan currently lacks a domestic natural gas network, therefore, supply via LNG to specific consumption sites, such as a power plant or a chemical plant, may be a more favourable option at present. Pipeline supply from Russia is likely more of a distant than a near-term possibility.

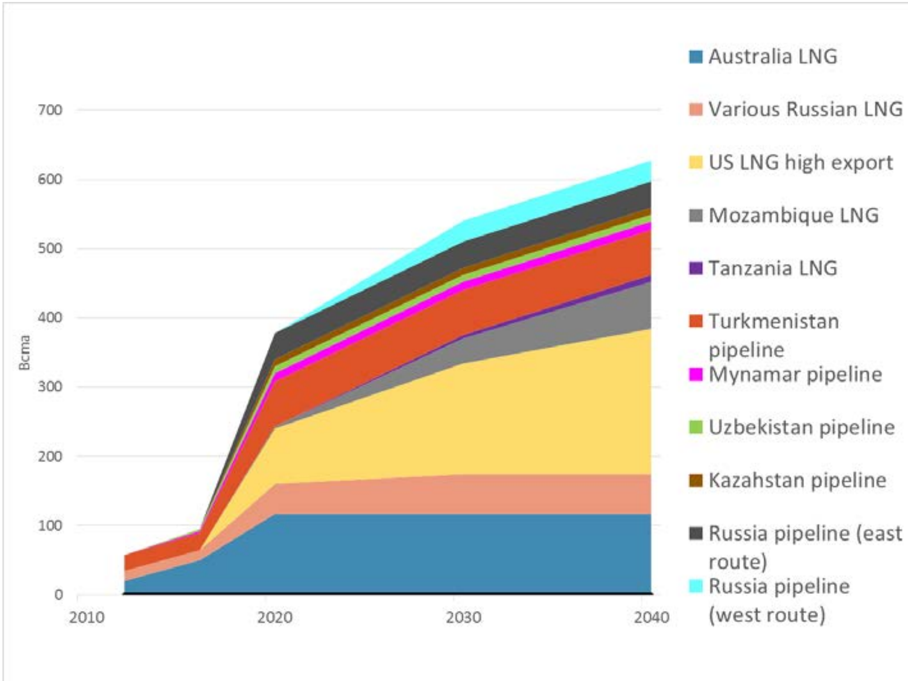
There have been protracted discussions about a gas pipeline from Russia to South Korea via North Korea, or directly from Russia to South Korea using a subsea route. In 2011 Gazprom, South Korea, and North Korea signed a preliminary agreement to construct a pipeline to the Korean peninsula to supply both Koreas with Russian gas (Centre for Strategic and International Studies, 2015; Norton Rose Fulbright, 2014). However, there has been no further progress on the scheme. With the political complexities, given the difficult relationship between the two Koreas, the project faces many hurdles. South Korea continues to express interest in Russian pipeline supply and is looking into other possible routes (NIKKEI Asian Review, 2014). Until a pipeline becomes a tangible option, Japan and South Korea, like Taiwan, will continue to depend on LNG.

LNG Supply

In addition to domestically produced gas prospects and increasing pipeline supply to China, significant supply to the region could come from various LNG projects. My research projections do not include all possible LNG supply options; instead, I focused on the long-term supply options (and their long-term price prospects) deemed to be the main competitors for prospective BC LNG exporters.

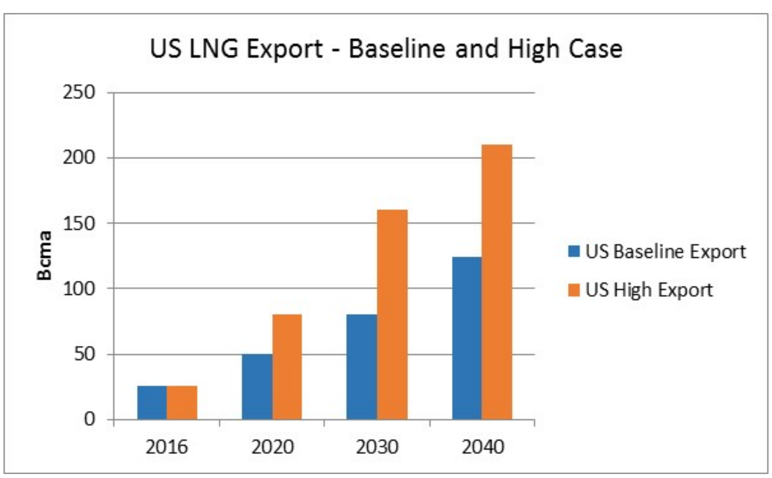
Many LNG projects, such as those from Australia, East Africa, and Russia, are experiencing delays, and projected supply volumes in my analysis reflect those delays. Only 50% of the Russian Yamal LNG project is included to reflect transport constraints to East Asia caused by harsh weather. Nevertheless, after 2020, the East Asian market appears to become a “buyer’s market” (Figure 20).

Figure 20: East Asia sources of supply



The biggest impact on the projected LNG supply volume for East Asia will likely come from US LNG exports. For 2040 these are highly uncertain, possibly ranging from 125 bcma in the baseline to 210 bcma in the US high export case (Figure 21). In my projections, this full expected volume is available for supply to the East Asian market, though it is possible that some quantities could be contracted with European buyers.

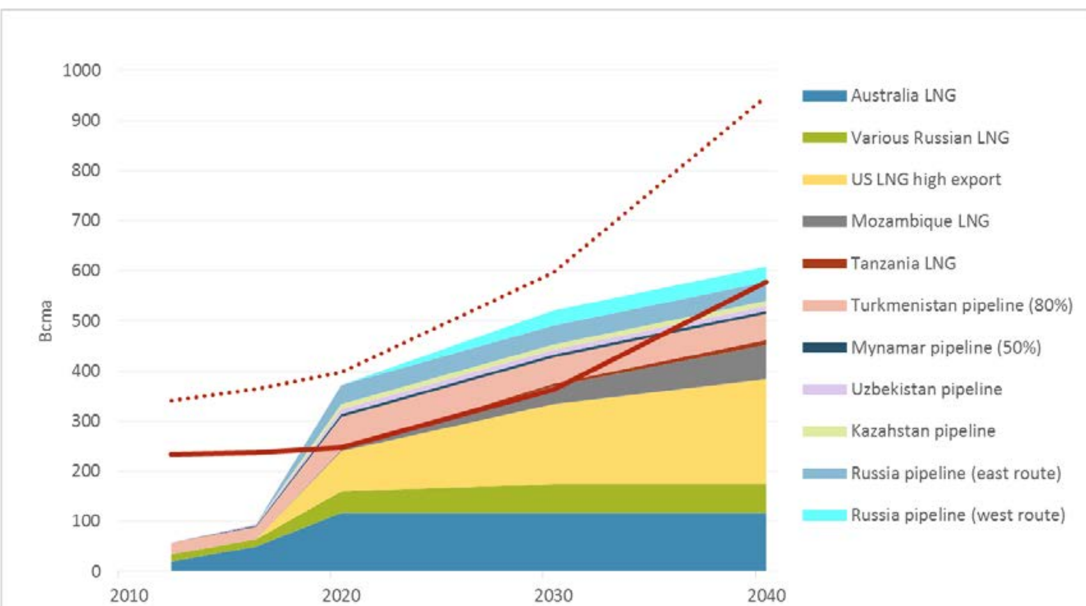
Figure 21: US LNG baseline and high export case



The US high export case is a likely scenario, considering a recent assessment showing that higher export quantities would have a marginal impact on US domestic gas prices. US decision makers likely will opt to increase the approved quantities for export, which, from a geopolitical perspective, will help counter-balance Russia's expansion into the East Asian market.

Figure 22 illustrates estimated aggregate demand in East Asia and the supply options competing to satisfy it. The impact of Chinese domestic production is highlighted by a gap between the two ascending red lines representing projected demand: the dotted line depicts aggregate East Asian demand without accounting for projected domestic production in China, whereas the solid line represents aggregate demand "net" of production in China. As shown on the graph, without domestic production, the total regional demand could exceed the identified pipeline and LNG supply options for the East Asian market. Due to its advantage in terms of energy security, domestic production is likely to be the preferred supply option for China if it is not too expensive relative to pipeline or LNG imports. Consequently, when reduced for the projected domestic production in China, estimated total supply exceeds likely aggregate demand in East Asia.

Figure 22: East Asia demand and supply projections



Bearing in mind that my projections do not account for all possible supply options to the region, the outlook for East Asian buyers for the coming decades is even more favourable. Therefore, an important consideration in the assessment of the East Asian market relates to the price competitiveness of all supply options competing for the projected regional demand.

Demand for natural gas, like any other good, depends on a number of drivers, including income, natural gas price, environmental and technological factors and break-throughs, and population growth, etc. The positive impact of income on energy demand, as well as the negative impact of price on demand, have been well documented in the literature. My demand forecasts appear to be relatively insensitive to price. As I elaborated in my analysis of East Asian market, a main reason is that environmental concerns will have a large impact on the demand for natural gas in electricity generation, industry, and to some extent transportation. Consequently, as income in China increases, so will natural gas use, even if it is more expensive than coal — whether for electricity generation, industrial uses or residential uses. Furthermore, because the supply sources available to the market are abundant and come from a variety of sources, there should not be big differences in the market price of gas even as the total demand rises significantly. The price will more likely be influenced by the rate of technological innovation in unconventional gas and LNG production and by China's geopolitical power in negotiations with suppliers like Russia.

Possible East Asia High Growth Demand

My analysis indicates that there is limited export potential for BC LNG to East Asia considering the projected baseline demand and supply balance. To establish what opportunities higher demand volumes could present, I examine high growth projected demand scenarios for East Asian countries.

In China, as noted, high growth of demand could result from stringent environmental policies driving energy policy, especially for coal consumption. Considering China's strategic interest in developing its unconventional shale gas resources, it is rather likely that the country will succeed in efforts to significantly increase its domestic natural gas production. If high domestic production in China does materialize, the Government will implement policies to facilitate the use of natural gas, leading to high natural gas demand growth.

With respect to the other three countries, the key factors leading to high demand growth involve implementation of policies related to the reduction of GHG emissions and the decreasing role of nuclear power. However, I deem that high natural gas demand growth is not very likely for Japan, South Korea, and Taiwan. While the use of nuclear power raises concerns, these countries will likely continue to rely on this fuel source in the future. Where the implementation of climate change policies and actions cause a reduction in the use of coal for power generation, the gap in energy supply is likely to be filled by increased use of nuclear power (and renewable energy) rather than natural gas.

Considering the arguments above, I calculate aggregate high East Asia demand by adding China's projected high growth demand volume with the baseline volumes of the other three countries. Forecasted possible high demand in East Asia for the 2016 – 2040 period is presented in Table 12.

Table 12: Possible East Asia high natural gas demand

(bcma)	2012	2016	2020	2030	2040
China high growth	144	189	250	490	960
Japan baseline	132	113	90	100	105
South Korea baseline	50	54	60	70	80
Taiwan baseline	15	16	20	20	25
TOTAL EAST ASIA DEMAND	341	372	420	680	1170

The possible high aggregate volume of natural gas demand reaches 1170 bcma in 2040, about 23% higher than the aggregate baseline demand in East Asia.

However, due to increased natural gas production in China, this scenario leads only to a modest increase in import requirements. Consequently, the region's aggregate demand, net of China's domestic production, in 2040 is about 620 bcma, or 7 % higher than in the baseline demand scenario.

5.3. Price Competitiveness of Supply Options

The international natural gas trade is not as transparent as oil, and price arrangements between buyers and sellers are often confidential. My price estimates are mostly from projections of likely production costs of various supply sources from academic, institutional and trade literature.

The US LNG supply price will depend on the future levels of Henry Hub prices. Sabine Pass, the first US project to receive approval from the US DOE, is to sell LNG on an FOB basis business model using the following price formula:

$$P(LNG) = 1.15 \times HH + B$$

where HH represents Henry Hub futures prices on the New York Mercantile Exchange (NYMEX) for the month of LNG delivery and B is a constant agreed between each buyer and seller. Henderson (2012) notes that the past low levels of Henry Hub gas prices do not reflect the long-run marginal cost of supply that companies will need to recover to continue investing in shale gas production. Studies conducted to ascertain the possible break-even price for US shale gas production identified a range from $4-6/MMBtu (4.13 – 6.20 2015$/MMBtu) over the next two decades as sufficient for continued production (Henderson, 2012). The current listing for Henry Hub futures on NYMEX shows prices to 2027, which in December 2020 is $3.6 and in December 2027 is $4.8/MMBtu[4].

[4] http://quotes.ino.com/exchanges/contracts.html?r=NYMEX_NN

Henderson (2012) estimates the cost of US LNG delivered in Asia based on the Sabine Pass LNG developer (Cheniere Energy) data, using different Henry Hub prices in the range of $3 – 5/MMBtu. Adding the costs of liquefaction ($3/MMBtu), transport ($3), and regasification ($0.4) he establishes the price range of $9.4 – 11.4/MMBtu for the US LNG (Henderson, 2012). A more recent estimate is provided by Gomes (2015) who calculates the US LNG export price based on the Henry Hub price of $3.52/MMBtu[5]. Gomes estimates the price by considering the following: fuel cost of 115% Henry Hub price (as quoted on NYMEX); liquefaction cost ($3.5/MMBtu) and shipping cost to Japan ($3/MMBtu). Using these parameters results in a price of $10.55/MMBtu (Gomes, 2015). For US LNG price in my analysis, I use the estimate provided by Gomes.

The oil-indexed Turkmenistan gas at the Chinese border costs more than the supply from Kazakhstan and Uzbekistan, partly due to transit fees paid to those two countries. The higher-price of Turkmenistan gas was offset though granting of equity stakes (the same was done with Kazakhstan), which allows the importer to share in revenues generated from high export prices (Henderson, 2011). Myanmar pipeline gas is even more expensive, but it does not require the same long distance transport to the end user as Central-Asian gas (International Energy Agency, 2014a).

The price of gas from the Russian Power of Siberia pipeline, likely linked to the price of oil products, is estimated at $10.5 / MMBtu (10.63 2015$/MMBtu). This would mean that the Power of Siberia pipeline gas price could be competitive with a potential LNG supply even after adding $2/MMBtu to transport Russian gas to China's east coast (Henderson, 2014). The expectation is that gas supplied from the west-route Altai Russian pipeline will be similarly priced. As assessed, the breakeven price for Altai pipeline gas at the Chinese border may be $9.89/MMBtu, or even as low as $9.5/MMBtu (Henderson, 2014). The (projected) low price of gas supplied by the Altai

[5] The forecast for Henry Hub - NYMEX Future Price (2020), (Gomes, 2015)

pipeline will put additional pressure on LNG suppliers with respect to their price competitiveness.

Table 13 presents my assessment of the probable delivery costs for the East Asia supply options, along with the references from which these estimates were derived. Throughout my research I gathered the most recent available estimates from multiple sources, made the best judgement on the most likely price while considering the assessments as well as the expertise and reputation of the source. In some instances, this involved sifting through conflicting evaluations. In those cases where I had access to multiple estimates, I considered those provided by the most reputable institutions in the energy field and used the mode of the available data set. On the other end of the spectrum, because estimates for some supply options are very scarce, I had to rely on one estimate or, in a few cases, make an assumption based on estimates provided for other supply options.

Using a variety of data sources increases the risk of errors in my analysis. I relied on the estimates by researchers who likely have better — but still limited — information about the actual supply contracts. Further, in case of oil-indexed prices, the current price levels reflect the price of oil with time-lags of 3-9 months though any price ceiling and floor provisions in the contract could limit the impact of the changing price of oil on the price of gas supply.

Table 13: East Asia supply - prices (in US dollars)

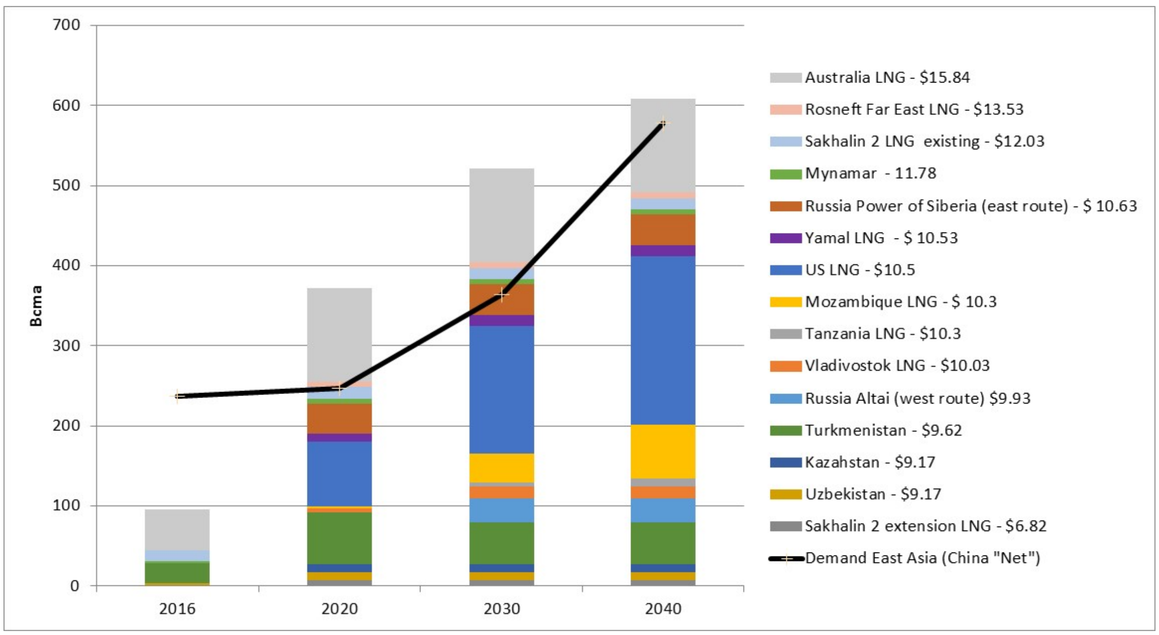
	Supply	Price (2015 US $)	Key Source
1	Sakhalin 2 LNG extension	$ 6.82	The Oxford Institute for Energy Studies, *The Russian Gas Matrix: How Markets are Driving Change* (2014) (Figure 8.4: Estimates of breakeven prices in Asia; price where in combination with pipeline project).
2	Uzbekistan	$ 9.17	IEA Medium Term Gas Market Report (2014).
3	Kazakhstan	$9.17	Assumed based on Uzbekistan estimates.
4	Turkmenistan	$9.62	The Oxford Institute for Energy Studies, *Political and Commercial Logic of Altai Pipeline* (2014).

5	Russia Altai pipeline (west route)	$ 9.93	The Oxford Institute for Energy Studies, *Political and Commercial Logic of Altai Pipeline* (2014).
6	Vladivostok LNG	$ 10.03	The Oxford Institute for Energy Studies, *The Russian Gas Matrix: How Markets are Driving Change* (2014); ("average breakeven price could be as low as $10/MMBtu for combined LNG and Power of Siberia pipeline project; though could be possibly bit higher for the LNG price").
7	Mozambique LNG	$10.30	Interfax Global Energy (2015), *Rumors of Mozambique demise greatly exaggerated,* ($9/MMBtu + $1.3 shipping cost to Asia*).*
8	Tanzania LNG	$10.30	Assumed based on Mozambique estimates.
9	US LNG	$10.50	The Oxford Institute for Energy Studies (2015), *Natural Gas in Canada: what are the options going forward*, (estimated using parameters on pg. 54 with $3.5 Henry Hub price based on the Futures price on NYMEX).
10	Yamal LNG	$10.53*	The Oxford Institute for Energy Studies (2014) *Potential Impact on Asia Gas Markets of Russia's Eastern Gas Strategy*.
11	Russia Power of Siberia pipeline (east route)	$10.63	US China Economic And Security Review Commission (2014).
12	Myanmar	$11.78	The Oxford Institute for Energy Studies, *Political and Commercial Logic of Altai Pipeline* (2014).
13	Sakhalin 2 LNG existing	$ 12.03	Assumed based on Energy Research Institute of the Russian Academy of Sciences and The Insitute of Energy Economics Japan (2014) *A new option for Russia's gas supply to Japan;* Executive Summary, Figure 2.
14	Rosneft "Far East" LNG	$13.53	The Oxford Institute for Energy Studies (2014) *Potential Impact on Asia Gas Markets of Russia's Eastern Gas Strategy*.
15	Australia LNG	$ 15.84	The Oxford Institute for Energy Studies, *Political and Commercial Logic of Altai Pipeline* (2014).

* *Average value taken from a range*

In Figure 23, I have arranged LNG supply options to all of East Asia, along with a few pipeline supply options to China, in ascending order of estimated production cost. Options lower in each column have lower estimated costs. The vertical distance for each option reflects its likely supply quantity at that production cost. The figure shows that, were it not for the high cost Australian supply, no contract would exceed $13 per MMBtu, and most would be below $12. The critical question is whether rising net gas demand will push up market prices to the highest cost supplies, or if lower cost suppliers can expand their output more than shown in the figure, and in so doing compete the market price down to $10 and possibly lower.

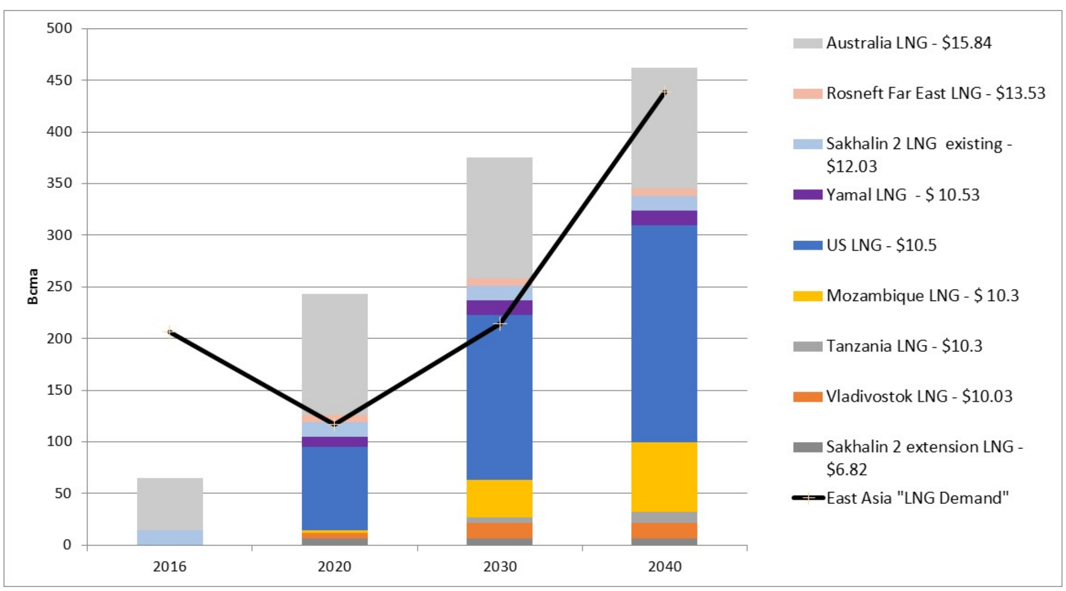
Figure 23: Projected total East Asia demand and supply options with their respective prices



As substantial volumes of competitively priced LNG compete, suppliers with production costs at the high end of the supply curve may find it difficult to proceed with their projects. New Australian LNG projects at the top of the supply curve are to start with their first deliveries to East Asian buyers. However, under current conditions, new Australian LNG exporters would not be able to find buyers at that price, just as any new project currently in the planning stage could not, if built under such a high cost structure. In the future, these Australian projects could seek to improve their market position through the increase of their liquefaction plant capacity and by expansion of current facilities. Such extensions would be brownfield developments and therefore might be more competitive compared with other greenfield LNG supply sources.

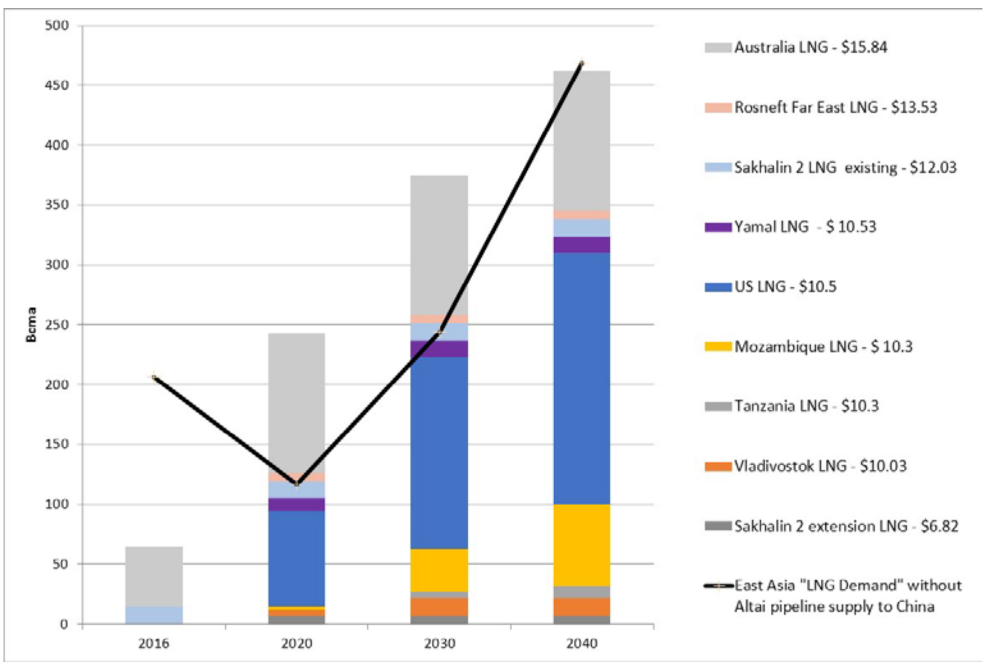
As China increases the diversity of its import supplies via increasing connectivity with inter-regional pipelines, new LNG terminals and storage facilities, the diversity of its supply and price options will increase post 2020. As noted, Japan, South Korea and Taiwan at present have access only to LNG supply. To address the issue of accessibility, the next step in my analysis is to match total demand volumes only with the LNG supply options. Because China has pipeline gas options (as presented in Table 11 "China Gas Demand and Pipeline Supply Balance – Adjusted for Pipeline Supply Uncertainties"), I subtract these from China's demand to isolate its potential "LNG demand". I add that to the demand of Japan, South Korea and Taiwan and match the total with LNG supply options, arranged according to their relative price competitiveness (Figure 24).

Figure 24: East Asia possible "LNG demand" compared to LNG supply options



In addition to price competitiveness, East Asian buyers may also consider security of supply of deliveries. For example, supply from Australia or the US may be deemed less risky than supply from Mozambique or Tanzania, two countries new to both the LNG industry and global trade (though these suppliers could attract buyers by offering contracts tailored to the buyers' current preferences, such as in the case of Mozambique, as noted in section 4.4). Further, political considerations may play a role in the decision making process. For example, China may decide not to further increase its supply dependency on Russia. This would mean 30 bcma less pipeline supply in 2030 - 2040, and increased supply opportunities for LNG producers (Figure 25).

Figure 25: East Asia possible "LNG demand" without 2nd Russian pipeline supply to China compared to LNG supply options



Availability of supply options with gas-to-gas pricing is already causing disruptions in price negotiations as East Asian buyers are increasingly showing interest in supply contracts with a "cost plus" structure (vs. oil-indexed supply). Going forward, expanded competition is very likely to facilitate the transition to a pricing mechanism which reflects gas-on-gas competition to meet demand. This transition will likely involve a period of parallel existence of oil-linked, gas-on-gas and hybrid priced contracts. Unlike Europe, the East Asian market does not have regional gas-trading hubs to provide a regional price reference point. Consequently, a reference point for sales contracts in the East Asian market in the medium- to long-term will likely be the US Henry Hub prices, until such time when an Asian hub is formed and is sufficiently liquid to take on this role (International Energy Agency, 2014d; Rogers & Stern, 2014). In addition to the change in price formation, East Asian buyers are likely to insist on increased flexibility of supply with respect to “take-or-pay” and “destination” provisions in the LNG sale contracts, as well as clear provisions specifying conditions for contract price renegotiations.

5.4. Competitiveness of BC LNG in the East Asian Market

The goal of this research project is to assess the likely evolution of the East Asian natural gas market over the next 25 years. A key outcome from this assessment is to produce a forecast of the likely demand for LNG from that region and, moreover, to provide key market price information for assessing the prospects of BC LNG exports. The next step, therefore, is to estimate the likely market-clearing price for LNG that suppliers from British Columbia would need to meet in order to sell to East Asian buyers.

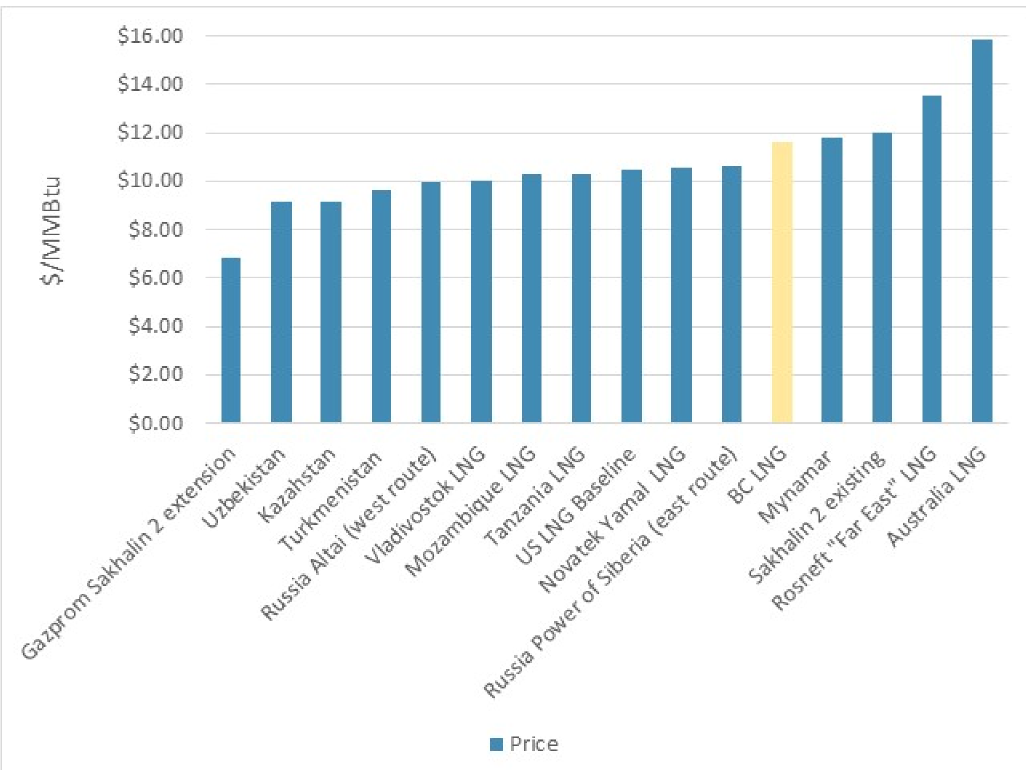
BC LNG exporters benefit from their proximity to the market, which lowers transportation costs. For example, BC to Asia transport takes only 9-10 days, compared to 20 or more days for US transport (Gomes, 2015). However, the key challenge for BC LNG projects is that they are greenfield investments with some cost disadvantages. There is also an additional cost to move the gas approximately 1,500 km from the gas fields to the coast for transport to the East Asian market (Gomes, 2015).

Analysts and researchers examining possible prices of BC LNG for the East Asian market provide several possible values. Macquarie (2012) estimated a breakeven price for BC LNG in Asia to be in the range of $8.6 - $10/MMBtu (8.89 2015$/MMBtu). Deutsche Bank and Ernst and Young (2012) estimate that a breakeven price may be $10/MMBtu (as quoted in Lee, 2014). A more recent estimate is provided by Gomes

(2015), calculating Canada's breakeven price (in Japan) to be US $11.61/MMBtu. Gomes assumes the price of gas based on an AECO (2019) quote of $2.91/MMBtu with the addition of relevant costs (pipeline fees of $2, liquefaction fees of $5.1, shipping to Japan of $1.5, sales tax of $0.1/MMBtu - 3.5% tax rate applied to the $2.91 LNG price).

Figure 26 illustrates the likely position of BC LNG on the supply curve, considering my assessment of the identified long-term supply options and their full production and delivery costs (as presented in Table 14). It indicates that BC LNG exports are likely to face intense competition in securing buyers for their supply.

Figure 26: Comparative price of supply to East Asia with BC LNG breakeven estimate



As suppliers compete for buyers, what will matter is not the price the BC government was looking at in 2012, but the relative production costs of all the alternative gas supply options to the East Asian market. Japan, South Korea and Taiwan are fully dependent on LNG imports and are a relatively stable market for LNG.

However, the market with the most demand is China, which may get very little of its gas from LNG because of the number of low cost options available. Therefore, cost competitiveness for BC LNG exporters in this market is going to be very important. BC LNG projects could find that the weaker Canadian dollar creates an advantageous business environment despite both positive and negative consequences. LNG would sell in the international market for US dollars, but labor and some other costs would be in the (weaker) Canadian dollar. On the other hand, some inputs to production, such as key machinery, would cost more if imported. The net effect could be positive, with the cost of developing BC LNG projects somewhat lower thanks to the weaker Canadian currency. Nevertheless, given the production and delivery costs of BC's LNG competitors, which include domestic Chinese production, gas imports by pipeline, and potential LNG producers around the world, there is a significant likelihood that the market potential for BC's LNG may be far less than envisioned back in 2012.

6. CONCLUSIONS

My investigation of East Asia's natural gas demand, its long-term supply options, and their likely market prices reveals that after 2020, East Asian countries will enter a period characterized by ample supply; additional LNG volumes will become available, and China will develop its domestic resources as it receives increased pipeline supply.

My projections indicate that demand for natural gas in East Asia will continue to grow between 2016 and 2040. The most significant contribution to the region's demand is that of China. However, China's LNG needs are not certain because of the simultaneous development of increased pipeline supply and indigenous production. High demand growth in China is likely to be matched with high domestic production so that an increase in natural gas demand will not result in a comparable increase in import needs. As China's domestic production picks up the pace, domestically produced gas will be a supply source for a large portion of the projected demand. For the remaining gap, and in addition to LNG import, China will have various pipeline supply options. Therefore, increasing demand in China may not necessarily result in increased LNG imports needs.

My research shows that the East Asian gas market is in flux. Besides increased volumes of supply, it is noteworthy that some of the supply options for the region will be priced based on gas-to-gas competition. For the first time, East Asian buyers are offered an alternative to traditional oil-indexed contracts. While contracts based on gas-on-gas competition do not guarantee low price levels, this means that LNG imports to China must compete with indigenous production and pipeline import options that will be very competitive.

Transition to gas-on-gas pricing in China may not happen quickly. The new pricing paradigm is emerging based on Henry Hub indexed supply contracts, a trading hub which reflects the US natural gas market, not fundamentals of the East Asian market. While plans for establishment of an East Asian natural gas trading hub already exist (possibly to be located in Shanghai), it is a long way before such a hub is formed and can provide a viable price reference for the market. Confidence in the legitimacy and transparency of natural gas prices generated in such a trading hub is a critical factor to encourage market players to trade at a hub so that it develops sufficient trading liquidity and can be a reliable reference point for the pricing of long-term supply contracts.

Nevertheless, the transition period in the East Asian market could see a quick rise and acceptance of hybrid pricing (contracts priced with both hub and oil indexation in a proportion agreed by the buyer and seller) as the validity of oil-indexation might be questioned now not only by East Asian buyers but also by their current and potential suppliers. Therefore, the evolution of this market will likely be characterized by a phase where there is the parallel existence of long-term contracts with oil-indexed prices (likely, at lower slopes than seen in the past), contracts with prices based on gas-to-gas competition, and contracts with hybrid formulae that combine both of those pricing methods. Increased competition among suppliers will increasingly reduce buyers' willingness to accept long-term, inflexible contracts, with price mechanisms which do not reflect a balancing of supply and demand. Rather, they will look for a competitive supply with pricing that is responsive to changing market conditions and that offers flexibility in terms of destination clauses, take-or-pay provisions, and price-reopener provisions.

Although there is an opportunity for BC LNG suppliers to export to East Asia, considering the projected dynamics of this market, such prospects are far from certain. In this increasingly competitive market, suppliers will look for ways to attract buyers. What will matter for BC LNG exporters is not the historic high price recorded in 2012, but the relative production costs of all the alternative gas supply options competing for the East Asian buyers. Prospective BC LNG exporters may have some advantages over other suppliers, but other current and potential suppliers have advantages over BC LNG. Consequently, BC's LNG market potential may be far less than envisioned back in 2012.

The projections generated in this assessment comprise an illustrative framework of the likely evolution of the East Asian natural gas market. In addition to unexpected errors in any long-term energy supply-demand forecasts, simplifications in my research may lead to inaccuracies. In my estimates, I concentrated on baseline and high-demand scenarios, and I focused only on the long-term supply options I deemed to be the main competitors for BC LNG. Further, I did not consider what might already be contracted supply and what is the actual portion of the projected demand that could be supplied. While these simplifications eased my analysis, they will inevitably lead to inaccuracies in my estimates. In addition, the opacity of the global natural gas trade and the limited availability of data further increases the potential for errors in my projections.

Further analysis of the market conditions and comprehensive supply and demand projections are needed in order to ascertain more accurately BC's LNG export potential. If the projections presented in this report are realistic, the consequences are not only for potential LNG developers but also for the provincial government's projected budget, local communities whose economic development prospects are linked to natural gas resource development, and businesses that anticipated increases of their activities from the new LNG sector.

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APPENDICES

Appendix A: Scenarios and Assumptions

Senarios built in this project are grounded in a literature review of reports by leading energy modeling agencies, academic reports, as well as natural gas and LNG industry reviews. Obtained data is complemented with information about current events and future trends in global energy sectors, international matters, geopolitics, relevant technologies, and economies, which may affect future supply and demand balances in natural gas markets. The projected period spans from 2016 to 2040. The assumed growth rates are applied to 2012 actual data as presented in the IEA Natural Gas Information Report, 2014 Edition.

China's Natural Gas Demand Growth

Underlining assumptions for both baseline and high demand growth scenarios are:

- GDP growth rate is slower than in the previous decades;
- Energy demand will slow down compared to previous decades, due to:
  - A slowdown in the GDP growth,
  - Restructuring of the economy to less energy-intensive industries and
  - Efforts to improve energy efficiency.

I. *Baseline Scenario* – 6% annual growth rate for the projected period

- The electricity sector in the baseline case still relies on coal, although the energy mix is restructured with a reduction in coal use.
- Electricity generation is the main source of increased demand, driven by environmental policies.
- China's coal demand peaks by around 2030.
- China is able to gradually overcome the geological and technological obstacles impeding domestic natural gas production growth.
- Domestic production rises at a 4.5% annual growth rate (baseline scenario for domestic production).
- China's shale gas industry makes progress in the next 5-10 years and domestic gas production will significantly increase after 2025. The Government undertakes the necessary reforms to facilitate further development of domestic production

II. *High Demand Growth Scenario* – 6% annual growth rate for the projected period

The high natural gas demand scenario is associated with higher domestic natural gas production. In a planned economy, with gas demand regulated by the authorities, demand growth projections largely reflect expectations concerning domestic natural gas production growth.

- Environmental rather than economic policy drives energy policy through controlling coal consumption, phasing out obsolete industrial capacity, and increasing clean-energy supplies. China supports global efforts to address climate change.
- A stringent, centrally administered carbon pricing mechanism is implemented to reflect environmental impacts of mining and use of coal in power generation.
- Coal use has reached a structural maximum and the use of coal peaks by 2020, earlier than assumed in the baseline case. This leads to a rapid increase in the use of natural gas in industry and the power sector.
- Electricity price reform follows implemented changes in natural gas pricing in order to stimulate increased use of natural gas in the power generation sector. The Chinese government implements an integrated nationwide electricity pricing system that reflects the real operating costs of plants using different fuels.
- Consequently, by 2040, new gas generation facilities replace 50% of the current coal generation capacity.

<u>China's Natural Gas Domestic Production</u>

I. *Baseline scenario* - 4.5% annual growth rate. In 2040, domestic production satisfies 50% of the demand.

   - Geological obstacles will not prevent China from developing the shale gas sector and increase domestic production in the long-term.
   - China's shale gas industry makes progress in the next 5-10 years and domestic gas production will increase after 2025.

II. *High production scenario* - 6% annual growth rate. In 2040, domestic production satisfies 57% of the demand.

   - In the high-production case, rapid implementation of necessary market reforms lead to higher-paced growth of the domestic production.
   - The growing level of expertise in the right technologies and techniques will help China meet its shale gas development goals.

- There are no constraints regarding water issues as new technologies, which allow for shale gas production with small quantities or no water, become available to China's shale gas sector.

Japan Natural Gas Demand

The main uncertainty for the natural gas demand growth in Japan relates to the future of nuclear energy. Like South Korea and Taiwan, Japan relies on LNG import; it is assumed that LNG supply satisfies 100% of demand.

I. *Baseline demand growth scenario* follows International Energy Agency's growth rate projection, and is decreasing at the rate of 0.8% per annum.

- Negative growth rate is a result of the gradual re-start of the nuclear plants and increased efforts for energy conservation and expansion of renewables.

II. *High demand growth scenario* assumes 0.6% annual growth rate.

- The key factor influencing high demand in the high-growth scenario is the implementation of stringent climate change policies and elimination of coal from the power mix, in addition to its replacement with natural gas.
- All coal-fired power generation is eliminated by 2040, which leads to increased demand for natural gas.

South Korea's Natural Gas Demand

In both scenarios, implementation of the Government's plans to reduce energy intensity to the OECD average influences natural gas demand. It is assumed that LNG supply satisfies 100% of natural gas demand.

I. *Baseline scenario* assumes the rate of 1.7% per annum, which corresponds to the government announced projected growth rate target.

- Although the target for the nuclear energy's share of installed capacity has been revised downward, there is still an expansion of the use of nuclear energy.
- Coal-fired capacity for the baseload power generation is expanded.

I. *High-growth scenario* assumes 2.2% annual growth rate.

- South Korea joins global efforts to address climate change and implements stringent climate change policies. This leads to natural gas replacing coal in its power mix by 2040.
- Construction of new coal generated power plants does not proceed and existing plants are replaced with gas-fired generation.

Taiwan Natural Gas Demand

The growth rate in both cases assumes the transformation into a high technology and service oriented economy, and the implementation of policies and actions necessary to meet the Government's energy conservation targets and energy efficiency improvements. It is assumed that LNG supply satisfies 100% of demand.

I. *Baseline scenario* projects 2% demand growth rate per annum.

- Reliance on nuclear energy continues as well as the use of coal for power generation.
- The lifespan of the existing nuclear facilities is extended or the facilities are replaced at the time of their retirement.
- Construction of the fourth nuclear plant, currently halted due to public opposition, continues and the plant begins operation.

II. *High growth scenario* projects a 3% growth rate

- Nuclear energy use is reduced: existing plants are retired and no further capacity is built.
- The Government implements policies in order to follow global activities related to climate change.
- Due to decreases in the use of coal and nuclear power, demand for natural gas increases.