THE GEOPOLITICS OF ENERGY PROJECT

FALLING SHORT:
A REALITY CHECK FOR GLOBAL LNG EXPORTS

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Cover photo: The Santos LNG Facility at Gladstone Harbour (Curtis Island, Australia). The project, which is still under construction, has become the most expensive integrated LNG export project ever at $54 billion (USD). (Courtesy Santos)

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About the Author

Leonardo Maugeri is currently an Associate with the Geopolitics of Energy Project and the Environment and Natural Resources Program at the Harvard Kennedy School's Belfer Center for Science and International Affairs.

One of the world's foremost experts on oil, gas, and energy, Maugeri has been one of the most distinguished top managers of Eni, the largest Italian company, which is also ranked number 6 among the largest international oil companies. At Eni, he held the position of Senior Executive Vice President of Strategies and Development (2000–2010) and eventually became Executive Chairman of Polimeri Europa, Eni's petrochemical branch (March 2010–June 2011). In 2008, Maugeri promoted the strategic alliance between Eni and the Massachusetts Institute of Technology, which—among other outcomes—led to the establishment of the Eni-MIT Solar Frontiers Center in 2010.

Maugeri is recognized worldwide for his books and seminal articles about energy, as well as for his part-time activity as a lecturer in some of the most prestigious universities and think-tanks. Since the early 2000s, he was among the few who affirmed that the world's oil was neither running out nor approaching its "peak-production." He was also among the few who predicted the revolution of shale-gas and tight oil.

He has published four books on energy, among them, *The Age of Oil: the Mythology, History, and Future of the World's Most Controversial Resource* (Praeger, 2006), which earned the Choice Price in the United States in 2007 and was translated into eleven languages. His latest book—*Beyond the Age of Oil: The Myths and Realities of Fossil Fuels and Their Alternatives*—was published in the United States in March 2010.

Mr. Maugeri has also written several articles that appeared in *The New York Times, Foreign Affairs*, *Science*, *Newsweek*, *The Wall Street Journal*, *Forbes*, *The National Interest*, *Scientific American*, *Oil & Gas Journal*, and *The Review of Environmental Economics and Policy*.

Mr. Maugeri has been a Visiting Scholar at MIT (2009–2010) and a member of MIT's External Energy Advisory Board. He also serves as an International Counselor of the Center for Strategic and International Studies (Washington, D.C.) and as a member of the Global Energy Advisory Board of Accenture, and he is a senior fellow of the Foreign Policy Association (New York).

In 2012, Maugeri published "Oil: the Next Revolution," in which he forecast an extensive U.S. shale oil boom and the collapse of oil prices before 2015. At the time of his analysis, Maugeri's was the only global voice to predict such evolutions. At the close of 2014, his prediction has proven prescient, with a surge in oil production and dramatic drops in oil prices.

About the Geopolitics of Energy Project

The Geopolitics of Energy Project explores the intersection of energy, security, and international politics. The project, launched in 2011, aims to improve our understanding of how energy demand and supply shape international politics – and vice versa. It also endeavors to inform policymakers and students about major challenges to global energy security and, where possible, to propose new ways of thinking about and addressing these issues. The project focuses both on conventional and alternative energies, as both will influence and be influenced by geopolitical realities.

Acknowledgements

After three publications in fewer than three years, I must start my acknowledgements with a special thanks to the Belfer Center for Science and International Affairs at the Harvard Kennedy School for providing the best, and most open-minded, intellectual environment for developing my analyses and opinions, even if controversial at the time of publication. Now that the world faces the phenomena anticipated in my previous Belfer Center studies ("Oil, The Next Revolution, 2012"; "The Shale Boom: A US Phenomenon", 2013), e.g. the collapse of oil prices and the skyrocketing growth of US shale and tight oil production, it is hard for me not to recall that it was only that kind of intellectual freedom, combined with the request for serious research, that allowed me to find room for my ideas at a time when much of the world held opposite views.

Specifically, I have a permanent debt of gratitude for Meghan O'Sullivan and Henry Lee, under whose Geopolitics of Energy Project and Environment and Natural Resources Program my studies were conducted. They directly allowed me to pursue my ideas and supported my work with suggestions and views that improved the quality of the final outcome. I also have an abiding debt of gratitude for the continuous support, suggestions, and friendship I received from Graham Allison, the director of the Belfer Center, as well as for his enthusiastic activity to spread the results of my studies.

For this paper, I have accumulated many debts to the executives and technicians who shared with their insights with me under the request of confidentiality. Thanks to them I could always maintain a close look at the reality on the field, a key factor for my usual "bottom-up" approach to the problems of the energy world.

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Finally, I have to thank Jonathan Hine, Jr. who took care of editing and streamlining the study, Amanda Sardonis who reviewed the final version and prepared the policy brief, Lauren Bloomberg who assisted me (since the beginning) in dealing with all the complexities of my work here, and the Belfer Center communications team – namely Josh Burek, Sharon Wilke, Andrew Facini, and Arielle Dworkin – who all contributed to the publication and launch of the paper.

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Executive Summary

The next few years will likely witness the largest increase ever of LNG global export capacity. On paper, the United States, Australia, and potentially Canada and Mozambique, could be the main contributors to such an increase.

However, the growth in LNG export capacity will probably fall short of the bullish expectations of more than 200 million tons per annum (MTpa). Huge cost overruns, poor planning, changing market conditions and emerging skinny margins will likely kill many projects across the world, or postpone their materialization to an uncertain future.

The US shale gas revolution will supply relatively cheap gas for future US LNG export schemes. It will also continue to defy gloomy views of shale gas as a temporary bubble. Most pessimistic analyses on US shale so far have grossly underestimated its potential for several reasons: stale data, extensive use of models that do not take into account the rapid evolution of knowledge and technology in the shale arena, persistent under-evaluation of per-well productivity increases and decreasing drilling and development costs, and a lack of specific productivity and costs data for the different areas of an individual shale/tight oil and gas formation.

At a US natural gas price of USD 4 MBtu, a number of US LNG export projects appear to be among the most cost-competitive new LNG projects globally. This is because, on paper, they could deliver gas between USD 10/MBtu (Europe) and USD 12/MBtu (Asia), including the cost of regasification. Furthermore, the "tolling-fee" nature of US LNG plants, the absence of destination clauses in US export contracts, and the de-linking of US gas prices from oil prices, make US LNG highly attractive as well as flexible.

However, US LNG export schemes may face several hurdles, leading to Darwinian competition among them and the survival of just a few of the planned projects. In particular, prolonged lower oil prices will make US LNG less attractive internationally, while planned capacity costs will likely increase, once more projects actually enter the construction phase. Along with decreasing interest in the sector by potential financial backers, this will make later LNG schemes less feasible, regardless of the number actually authorized by the US Department of Energy. Consequently, by 2020 US actual LNG export capacity to non-Free Trade Agreements (FTA) countries will hardly reach more than 60-70 MTpa, making it difficult for the United States to have a significant impact on the different international gas markets.

Australian LNG seems to be the worst business case globally. Huge cost overruns in the last few years have made its overall cost skyrocket to USD 14-16 per MBtu (upstream plus downstream), a cost that would make most Australian LNG schemes unprofitable. The fall of oil prices could make the story even more worrisome for investors.

Nevertheless, several LNG plants are under construction in Australia, and they will come online in the next few years no matter how the market situation evolves. Owners will consider their capital expenditures as sunk costs, and will strive to cover their operating costs. Because of its high cost and destination clauses already agreed upon, Australian LNG has no

outlet but the Asian markets, and it will not affect substantially the global gas market. Australian LNG export projects that are not under construction, including trains to be added later to plants already under construction, will likely be postponed indefinitely, because of market conditions.

Other newly discovered, huge gas resources in different parts of the world are unlikely to turn into LNG exports before 2020. In general terms, most of them are still awaiting actual development plans and/or final investment decisions. The current change in market conditions will further delay their materialization, adding also to the growing pressure on oil and gas companies to restore a certain discipline to their capital expenditures.

Canada will likely by the hardest hit by the new "chill wind" blowing over LNG projects. Even before the fall of oil prices, not a single planned Canadian LNG export scheme (fifteen, with a total export capacity of more than 57 MTpa) had reached a final investment decision. In particular, several unsolved problems concern British Columbia, where most of the LNG plants would be located. Those problems include strong opposition by local population to the construction of pipelines and other essential facilities, lack of basic infrastructure, environmental hurdles, shortage of skilled people, etc.

When oil prices are above USD 100 per barrel, the problems in British Columbia could make Canadian LNG projects slightly profitable – on paper. However, solving those problems could make actual costs in British Columbia much higher than planned, putting LNG profitability at risk even in a high oil price scenario. Combined with the fall of oil prices, these reasons make it highly improbable that Canada will contribute to the growth of global LNG export capacity by 2020, except perhaps for one project (Goldboro LNG).

Mozambique, another potential contributor to global LNG, still lacks clearly defined development plans with associated costs. The country's geography, its lack of both basic infrastructure and skilled people, as well as other problems, will make overall LNG development cost a challenging factor in the current market scenario for the companies holding the major portion of the gas resources in the country. It is highly unlikely that actual LNG export plants will materialize before 2020.

An arial shot of the Sabine Pass LNG Terminal in Cameron Parish, Louisana. Operated since 2008, the terminal is now undergoing renovations to add gas liquefaction services.
(Flickr user "Think Defense", CC license BY-NC 2.0)

1. Introduction

During the 20th Century, natural gas developed regionally, depending on the proximity of natural gas resources and consumption markets. The high cost of transporting and distributing natural gas made up most of the price consumers had to pay for it. As a result, a global gas market never materialized, but three big regional markets emerged: North America, Europe, and Asia.

In the last few years, however, greater integration of those regional markets has appeared to be at hand, thus creating the conditions for a global gas market. Key to this evolution has been the apparent explosion of the liquefied natural gas (LNG) business, which allows it to be shipped the same way as oil.

So far, LNG has represented a niche market, about 10 percent of global gas consumption. This has been mainly due to its high costs. However, large discoveries of natural gas in the United States, Australia, and Canada, among others, have the potential to change this pattern.

In order to monetize their huge gas discoveries in those countries, companies have scrambled to propose or start new LNG projects that, on paper, could change the structure of the market, making it significantly liquid metaphorically and literally) at a global level. The concurrent high growth of natural gas demand in Asia, particularly in China, and the European search for alternatives to natural gas from Russia seem to offer these LNG projects plenty of room for deployment.

However, several factors suggest that the apparent boom of LNG hides many problems, which could undermine its actual extent. Most LNG future supplies are turning out to be too costly for their investors and too expensive to address the global market at large. Also, they are based on formulas (in particular, those with rigid destination clauses) that limit their ability to achieve a more liquid global market, and to promote a convergence of international natural gas prices.

2. Some fundamentals about natural gas and LNG

The only part of natural gas (typically more than 90 percent) that we consume every day for heating, producing electricity, etc. is methane. Almost all sources treat "natural gas" and "methane" as synonyms.

Only 30 percent of the gas consumed worldwide is exported, mostly via pipelines. Just one third of the exported gas, or about 10 percent of gas consumed every year, is shipped in liquid form, i.e., as LNG.

By comparison, more than 60 percent of oil is exported internationally. The problem is that it takes about a thousand times more methane by volume than oil to provide the same energy content. As a consequence, transporting natural gas is very expensive, and it becomes even more expensive the farther the distance to a final market.

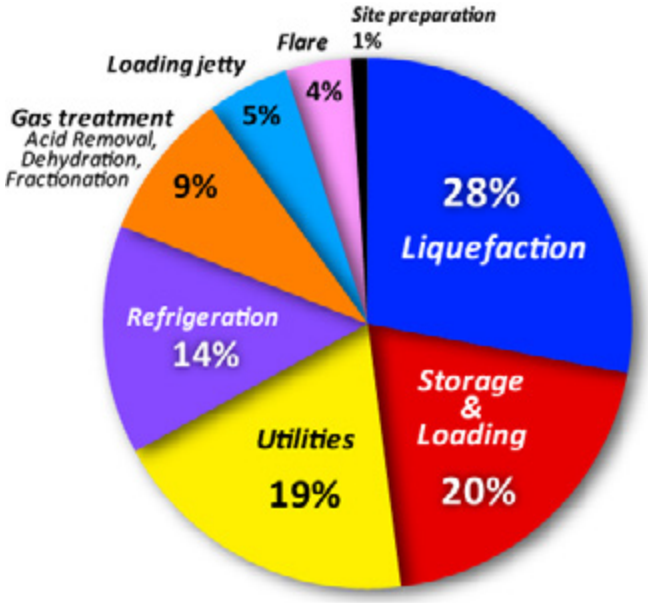
Indeed, for much of its history, the transportation and distribution of natural gas could represent 80 percent of its industrial cost. The situation is better today, but the transportation and logistics of moving gas over long distances (generally more than 600 miles/1,000 kilometers) still constitute much of its final cost, often about 50 percent. When the distance is longer than 2,000 kilometers, transporting gas via pipeline can become economically infeasible. In this case, LNG may be an option <u>if</u> access to the sea is available.

Liquefying methane involves cooling it to -161°C (-258° Fahrenheit), reducing its volume by about six hundred times. Liquefaction schemes usually involve the building of multiple plants in the same area. In the industry jargon, each plant is called a "liquefaction train", or simply "train." Each operates independently. Internationally, capacity is indicated in millions of metric tons per year (Mtpa). Each ton equals about 1,380 million cubic meters or 48,700 million cubic feet, and has a heating value of approximately 52 million British thermal units (MBtu).[1]

LNG capacity is normally referred to as "nameplate" or "nominal" capacity, indicating the maximum annual liquefaction capacity of a plant. The seasonal demand for natural gas, which typically peaks during wintertime, and the purchase strategies of different buyers cause only part of the nominal capacity to be used each year. LNG economists usually assume a 75 percent utilization rate.

Liquefaction accounts for only about 30% of the costs of an LNG export plant. The plant also requires storage and loading capacity, refrigeration, power generation, natural gas treatment (acid removal, dehydration, etc.), pipelines, etc., shown in Figure 1.

Fig. 1 – LNG Export Plant Cost Breakdown



Source: Author Estimates from Several Sources

Most of these costs can be greatly reduced when an LNG plant is built as a "brownfield" project, that is, within an already existing plant (for example, a re-gasification terminal, as is happening in the United States). Conversely, "greenfield" projects, developed where no infrastructure exists, must include all these costs.

Several sources simply use "liquefaction costs" to indicate all these costs, but a more appropriate term would be "capacity costs." They should be calculated against a ton (or million tons) of capacity.

The capacity costs of the LNG chain may represent an insurmountable problem, depending on the location of an LNG development project and whether it is brownfield or greenfield. In particular, costs have skyrocketed in the last few years as a result of oil and gas upstream (e.g., exploration and production) investments worldwide, which have driven continuous inflation across the sector.

Box 1 – Inflation Costs in the LNG Sector

In the last few years, one of the main problems concerning LNG capacity costs has been growing inflation, which has exceeded that recorded in the oil and gas upstream sector. LNG capacity costs have sometimes tripled, making even recent estimates fall far short.

Each country may present its own inflation elements, be they labor market conditions, the cost of steel and other essential components of an LNG project, the incentives needed to attract skilled personnel, etc. Costs may also vary depending on the regulatory framework in a country, particularly with regard to environmental protection.

A combination of general and specific inflation drivers has caused the range of LNG economics to widen dramatically since 2010. Today, the lower range for building 1 ton of capacity seems to oscillate around USD 600-700 in the United States (brownfield), while the upper range exceeds USD 2,000 (greenfield) in Australia. However, most costs in the lower range are based on estimates performed by companies before actual construction. Typically, cost overruns, including those caused by inflation, always materialize during the construction phase.

Given this cost explosion in many countries, several companies are thinking of abandoning traditional onshore LNG export plants to embrace so-called floating liquefaction. This involves building a liquefaction vessel, transporting it to a position offshore, where the LNG will be produced, and installing it. This way, an LNG producer may bypass the challenges posed by a country's tight or expensive labor market, as well as onerous onshore regulation. While a few of these vessels are under construction, the economic feasibility of large scale floating systems raises several doubts (see *Section 9*).

The high cost of LNG requires potential sellers to secure long-term contracts with buyers, called off-take agreements, covering a significant part (usually more than 70 percent) of the planned capacity before starting actual construction of an LNG plant. Usually, off-take agreements are a fundamental prerequisite to obtain the necessary financing for the plant construction.

Since its inception in the 1960s, the LNG business has been dominated by a model whereby the plant owners are integrated oil companies that also produce natural gas. Consequently, they sell both the commodity and the services needed to transform it into a liquid. Since then, the price of liquefaction services has varied from place to place, while the price of natural gas has been indexed to that of oil in most LNG contracts.

Similar to what happens in selling gas by pipeline, LNG sellers require a *"Take-or-Pay" (ToP)* clause, which obliges buyers to pay for a minimum annual volume of gas even if they do not take it all. The contracts also contain a *"destination clause"*, which obliges buyers to use no less than 80-90 percent of the gas they purchase in a pre-defined market.

A completely different formula, however, is now emerging in the United States, based on "tolling fee" agreements, where the LNG plant owner is not an integrated company, but only sells capacity services (See Box 2).

Box 2 – "Tolling-Fee" Agreements in the LNG Sector"

Tolling-fee formulas in the LNG sector are emerging in the United States. In this case, usually the plant owner is not an integrated oil company and does not produce gas, but sells "capacity" services (liquefaction, storage, gas treatment, etc.), collecting a toll that is always the same, regardless of how much the buyer pays for natural gas. This way, the LNG plant owner is free of any commodity risk, although it bears the performance risk associated with correctly planning the interplay between storage capacity, liquefaction and shipping.

At any given moment, an LNG plant owner must ensure that all the pieces of the puzzle are perfectly aligned according to his numerous clients requests, so that the allocation of capacity respects contractual agreements. This complicates the work of LNG plants owners more than that of integrated operators. In fact, the former need to fine tune both the intake of natural gas from multiple sources, and the requests for liquefaction coming from other multiple sources.

For example, incorrect planning may result in there not being enough storage capacity for natural gas, affecting the ability to deliver on time. Such factors could incur significant penalties.

In turn, the buyer purchases the commodity from a third source (which could also be a natural gas producer with no liquefaction capacity). Once natural gas is liquefied, the buyer is free to send it wherever, with total flexibility. The buyer may also decide not to buy gas at all, but still he has to pay the full toll for any LNG capacity that it has contracted with the plant owner. This way, the buyer assumes the risk from volatile natural gas prices, but may avoid the risk of overpaying for gas by renouncing to buy gas at all. Furthermore, in the United States, the price of natural gas is not indexed to oil, but depends of the daily fluctuations of the benchmark Henry Hub (Louisiana) price.

Once liquefied, methane is shipped to final markets in special, cooled vessels, which keep the gas liquid until final docking.

Box 3 – LNG vessels and economics

At the end of 2013, the total fleet of LNG ships was made up of 357 carriers of all types with a combined capacity of 54 million cubic meters, and an average capacity of about 150,000 cubic meters. A big wave of new vessels becoming operational since 2013 will continue to add capacity through 2017.[2]

LNG vessels are typically chartered on a daily rates basis. Historically, daily rates have tended to oscillate dramatically, depending on of the mismatch between demand and supply, and the time lag between the order for new ships and actual market conditions when the new vessels become available.

The last 10 years offer a good example of the high volatility of this sector. Before the 2008 economic crisis, charter rates run on average between USD 65,000 and USD 70,000 a day, compared with break-even costs of about USD 60,000. Then in 2009 they dropped to about USD 30,000 a day as a consequence of the delay of many LNG projects worldwide (in its turn, a consequence of the economic crisis). The price downturn led ship owners to block new orders for vessels, so that as new liquefaction projects came online in 2011 and 2012, LNG vessels were in short supply and daily rates picked up rapidly and peaked at USD 150,000 a day in 2012.

Between 2013 and 2014 a new-build ordering cycle began, with more than 120 vessels due to come online. Once again, this depressed the daily rates for LNG vessels to about USD 70,000 a day in early 2014.[3]

LNG is finally returned to a gaseous state by heating it at a regasification terminal. Then it is sent to gas pipelines, which transport it to the final consumers.

As a rule of thumb, the production and logistics costs of the LNG chain (liquefaction, transport, and regasification) are at least twice as much as the costs of transporting natural gas via pipeline, for the same volumes of gas produced and transported.

At the end of 2013, worldwide liquefaction capacity was about 291 Mtpa, equivalent to more than 400 billion cubic meters (Bcm). Conversely, global nominal regasification capacity was more than twice the liquefaction capacity, standing at 688 Mtpa at the end of 2013 (or about 950 Bcm), and growing faster than the latter. The rate of LNG utilization was less than 50 percent, and the actual trade of LNG was just 237 Mtpa.[4]

Because of a lack of domestic energy resources and the impossibility of taking delivery through pipelines or by rail or truck, Japan and South Korea are the largest LNG consumers globally, together totaling almost 55 percent of world's LNG consumption (Japan 37 percent). In the early 2000s, Qatar emerged as the largest producer and exporter of LNG, with a total capacity of almost 80 MTpa.

3. The rush to LNG and the price dilemma

According to its 2014 Medium-Term Gas Market Report, the International Energy Agency (IEA) sees global gas demand rising by 2.2 percent per year through the end of this decade.

LNG will have the lion's share of demand growth, thanks particularly to LNG projects in Australia and North America, which could increase LNG trade by 40 percent to reach 450 billion cubic meters by 2019.[5]

Almost the same view is shared by the International Gas Union, according to which more than 100 Mtpa of new capacity is scheduled to come online between 2015 and 2018. Australia will lead the way. With 62 Mtpa of new capacity expected online by 2018, the country is set to surpass Qatar as the world's largest exporter.[6]

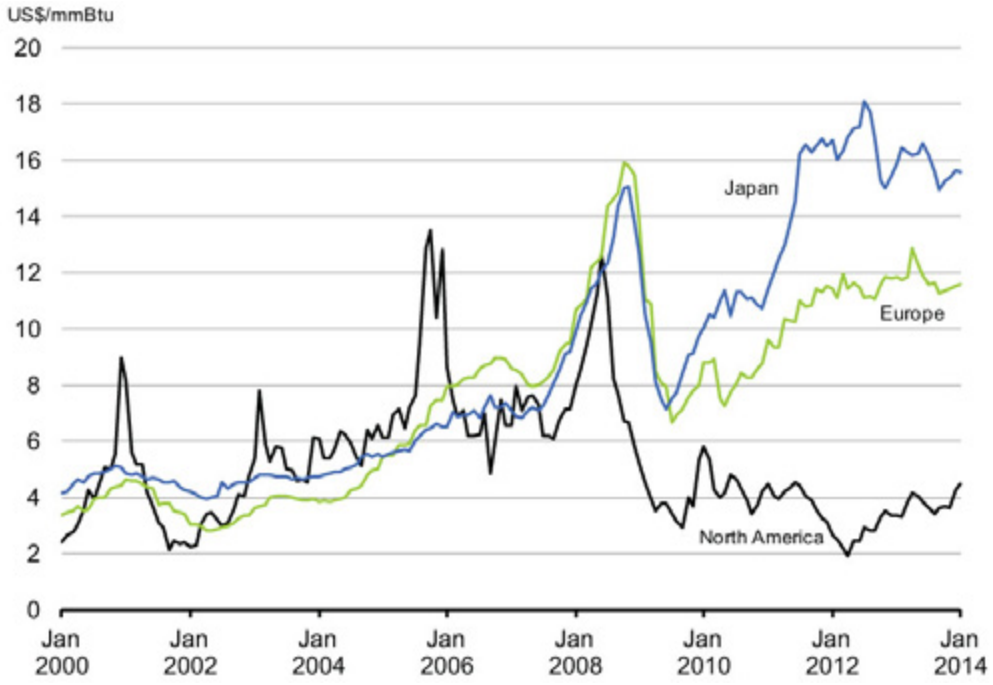
These forecasts are even more moderate than several others.

When the rush for LNG started in 1996, there were only eight producers of LNG in the world. Now some scenarios suggest that, by 2020, there could be more than twenty, with a total liquefaction capacity well above 450 MTpa, particularly if the long queue of US LNG export projects is approved. However, projections of this kind need to be considered prudently.

While growing demand for natural gas, particularly in China, is supporting the growth of the LNG business, and thus the globalization of the natural gas market, the future price of natural gas remains the key element in determining the extent of the LNG boom. And this represents a big question mark.

As shown in Figure 2, natural gas prices reached their highest levels in Japan (and China) between 2011 and 2013, oscillating between USD 15-18 per MBtu, and leading to a general ramp-up throughout Asia. Conversely, they plummeted in the United States, owing to overproduction from shale gas. They stayed on average between USD 11-12 per MBtu in Europe.

Fig. 2 – Natural Gas prices in US, Europe and Japan, 2000-2014



Source: World Bank.

In late 2014, however, LNG spot prices plummeted in both Asia and Europe, to single-digit territory in Asia for the first time since the March 2011 Fukushima disaster in Japan, and to slightly more than USD 9 MBtu in Europe.[7]

Prices changes are typical of the seasonal nature of natural gas demand, which peaks during the winter and slows significantly the rest of the year. The apparent free fall of LNG spot prices in Asia and, to a lesser extent, in Europe just as winter approaches is the result of both overcapacity and the buyers' growing negotiating strength. Both elements portend a weakening trend for LNG prices in the near future.

Exacerbating matters is the effect of indexing natural gas prices to oil in most contracts outside the United States. For many years, natural gas was considered a substitute for certain petroleum products, particularly for heating and industrial use. When oil-indexation spread worldwide (between the 1960s and the 1970s), petroleum products were still the main sources for those kinds of consumption. Over time, this link weakened dramatically, particularly in the OECD countries. The United States abandoned oil-indexing in the 1980's; the United Kingdom shortly thereafter.

In the last decade, the rise of oil prices has driven gas prices up in both Europe and Asia. In their turn, high gas prices, coupled with the economic crisis and a significant increase in power production from renewables, have caused a significant reduction in European gas demand. This

has led to a tectonic shift in the European Union (EU) gas market. In just one year (2013-2014), the EU shifted from oil-indexed dominated gas contracts to hybrid pricing systems (mostly based on gas hub indexation, only partially related to oil prices) which, by the end of 2014, represented more than 50 percent of all gas consumed in the region. The pressure to revise existing supply contracts downward has thus increased, and most suppliers of gas to Europe have already agreed to discount the price of gas (See Box 4).

The latter phenomenon was facilitated by a peculiar effect of the US shale gas revolution. As noted by Jason Bordoff and Trevor Houser, "The US shale boom has already helped European consumers and hurt Russian producers by expanding global gas supply and freeing up LNG shipments previously planned for the US market."[8]

Box 4 – The European problems with natural gas

Natural gas demand in Europe has not yet returned to the levels reached before the 2008 financial crisis. In addition to the prolonged effects of the crisis, other reasons for the sluggish gas consumption include the large build-up of renewable capacity and the increased availability of low-cost, imported coal.

Indeed, the European gas market lives a paradox. During most of the year, it enjoys a steady oversupply, but during wintertime, it may fall prey to gas supply disruptions that cannot be offset. In other words, it may face gas shortages just when gas is critical for heating.

This peculiar situation stems from the restricted number of European gas suppliers and the predominance of just three of them: Russia, Algeria, and Norway. In particular, Russia supplies almost 30 percent of European gas needs, or about 150 Bcm per year (almost 15 Bcf per day). The continuous threat of a clash between Russia and Ukraine, which could disrupt Russian gas supplies to Europe, is a source of major concern for Europe. Ukraine lies in the corridor through which most Russian gas exports to Europe pass today, even with the diversification enabled by the Nord Stream pipeline connecting Russia and Germany directly. This vulnerability is the main reason that Europe has sought additional and alternative sources of imports for many years.

So far, the high cost of most alternatives and incoherent energy policies pursued by several European countries and the EU itself have precluded a viable solution. New LNG imports, particularly from the United States, now seem to offer a new opportunity to European consumers. However, the risks of duplicating imports during times of oversupply and of incurring excessive costs have so far tempered the willingness of European companies to buy new gas and, most important, to build the infrastructure needed to import it.

The lack of infrastructure deserves a short explanation.

Several European gas pipelines remain disconnected because of national interests, so that natural gas cannot freely move from one place to another. More important, the European Union lacks a strategic gas reserve, similar to the US Strategic Petroleum Reserve, which could allow it to even out its seasonal demand-supply situation. Today, so-called "strategic" reserves (that is, usable only in a crisis) are left to the initiative of private firms under a regulation regime that ensures an insufficient return on capital to the owners of the storage sites. The result: strategic reserves currently available are completely inadequate to face a real emergency situation. Moreover, until now each country has built its own reserves, giving rise to undesirable economic and systemic imbalances.

For several years now, LNG buyers in Asia have openly challenged the oil-indexation formula, which still dominates gas trading in the region. After 2011, the pressure became much stronger, particularly after the emergence of future LNG supplies from the United States. Those prices, uncoupled from oil, appeared more competitive. So far, most LNG current and potential suppliers to Asian markets, particularly Australians and Canadians, have resisted significant changes. Their argument is that, without oil-indexation, some LNG projects will never materialize due to their high cost, thus depriving the market of essential supplies.

In the second half of 2014, however, the rapid decline of oil prices undermined the possibility of gas prices remaining as high as they have been since 2010. While posing a significant threat to the economics of new LNG projects, the oil price fall could once again make gas prices indexed to oil more attractive than non-indexed US exports of natural gas.

Adding uncertainty is the unclear scenario for natural gas demand in Asia. The price escalation in the region after 2011 was the result of the surging consumption of LNG by Japan after the Fukushima nuclear accident, which led the Japanese government to suspend production from all its nuclear plants and to turn to natural gas and other fossil fuels to offset the lack of nuclear energy. The current Japanese government, however, seems inclined to revisit that decision and to re-open, at least partially, the nuclear energy option, a decision that could entail a significant re-sizing of gas demand (See Box 5).

Box 5 – Japan's demand for natural gas and the lingering impact of nuclear energy

Japan is by far the largest importer of LNG worldwide, with a 37-percent share of the global market. Thus, its influence on price formation in Asia is of the highest importance.

The surge of Japanese imports after Fukushima had a distortive effect on competition for volumes in the spot market and pushed prices to their highest levels ever. Furthermore, the initial decision by the Japanese government to ban forever either the construction of new nuclear plants or the expansion of existing ones, to allow for the restarting of closed nuclear plants only after rigorous inspection by the Nuclear Regulatory Authority, and to require the decommissioning of all nuclear plants after 40 years of operations, was generally perceived as a rejection of nuclear energy. In turn, this convinced most observers that natural gas would become the fuel of choice for Japanese energy in the future.

But on April 2014, the new Japanese government approved an energy policy that reversed the former government stance, allowing more flexible terms to restart and run existing nuclear plants. While it is considering reopening 16 nuclear plants, another 32 plants may never be reopened. Thus, although the timing and extent of future Japanese nuclear energy is still uncertain, the prospect of a Japan without nuclear energy has changed significantly.

China's appetite for gas is surely huge, but the ways to satisfy it, along with their timing, may have important consequences for LNG. The country has already in place programs to build new gas pipelines, and in August 2014, it signed a historic contract with Russia to begin importing Russian natural gas by the end of this decade. In the short to medium term, pipeline gas is a direct competitor of LNG (See Box 6). In the long term, China could also rely on significant shale gas resources.

Finally, the overall picture of Chinese and Asian demand for natural gas remains closely connected with the real feasibility of gas seriously competing with much cheaper coal. Although China and other countries are trying to diminish the use of coal for environmental reasons, in the

short to medium term, coal remains a tempting alternative, because of its low cost. Since 2011, the price of coal has fallen from more than USD 100 per ton to USD 75 per ton. As reported by the IEA, "In the Asian markets, to produce electricity from LNG is 2.2 times more expensive than from coal. If there is no regulation in [such] power markets, then those countries go and build coal-fired plants."[9]

This short outlook serves only to remind us that, on the demand and price side, things are not written in stone. There are too many evolving factors and variables that require careful monitoring before running the risk of overbuilding LNG export capacity.

This warning is even more important when looking at the specific cases of the largest potential LNG exporters.

Taiwanese President Ma Ying-jeou (馬英九) inspects CPC Corp.'s LNG receiving terminal in Yongan District, Kaohsiung City, Taiwan. June 2, 2013. (Flickr user 總統府(presidentialoffice), CC license BY-NC-ND 2.0)

Box 6 – The puzzle of China and natural gas

According to the largest Chinese producer, Petrochina (the listed arm of the state-owned giant, China National Petroleum Company [CNPC]), China's apparent gas consumption hit 169 Bcm in 2013 (more than 16 billion cubic feet per day), growing an average of 16 percent annually since 2006. By 2020, it could more than double, and reach 360 Bcm, driven in particular by the government's will to reduce coal-induced pollution across the country.[10]

Such impressive growth would make ample room for more gas imports. However, Petrochina's parent company, CNPC, is the only Chinese importer of gas via pipeline, and already has contracts to import gas via pipeline totaling 120 Bcm per year over the next few years.

Most of that, 80 Bcm per year, will come from Central Asian pipeline systems, and includes 65 Bcm/yr from Turkmenistan, 10 Bcm/yr from Uzbekistan, and 5 Bcm/yr from Kazakhstan.[11]

In addition to the supply from Central Asia, in May 2014, CNPC and Russia's Gazprom signed a long-awaited, historic agreement for the first exports of Russian gas to China. The initial contract amounts to 38 Bcm per year. Gas delivery is due to start in 2018.

Although natural gas imported by pipeline needs to cross the country to reach its eastern provinces, covering distances of about 1,800-2,400 kilometers, it apparently remains a more economical option than importing LNG. There are still many unresolved issues concerning the actual price, or price formula, of the Sino-Russian agreement. Both parties are still actively trying to obtain better conditions, as extensively explained by Morena Skalamera in a recent paper.[12]

According to insiders, as of September 2014, before the fall of oil prices (The Russians insisted on an oil-indexed price), the broad range the parties were negotiating was USD 10-12 MBtu, most likely towards the upper range of that band.[13]

According to the state company Sinopec, in the first quarter of 2014, the average price of gas imported via pipeline from central Asia was USD 10.11 per million cubic feet (Mcf – 1 Mcf = 1 MBtu), compared to USD 12.44 per Mcf for imported LNG.[14]

Sinopec also revealed that it is facing problems finding customers for its contract to lift 2 million tons/yr from Exxon Mobil's new Papua New Guinea plant, because that gas is too expensive for Chinese end-users.[15] *The same problem looms large on plans to build at least some of the planned LNG plants in China.*

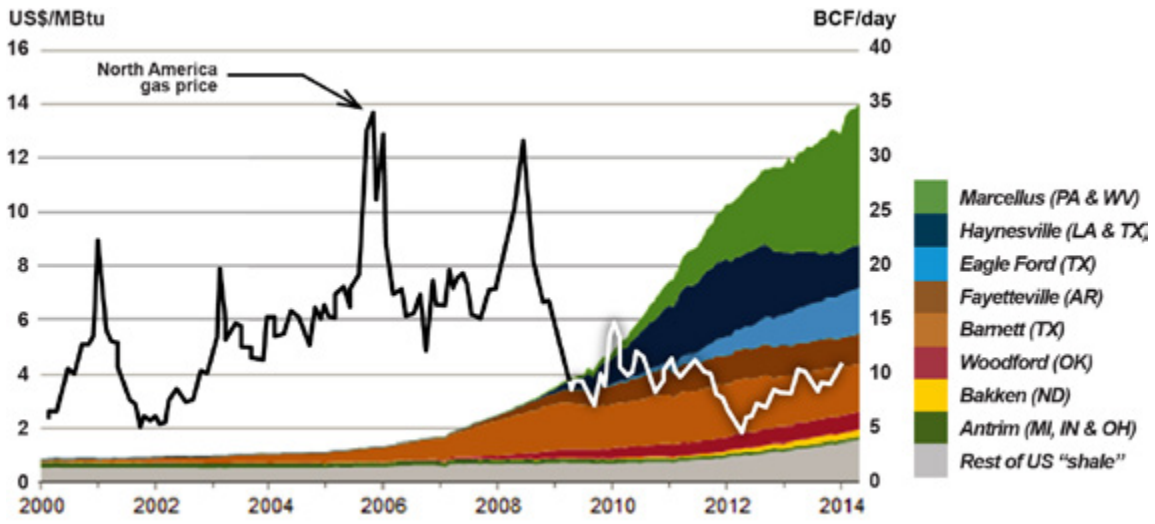
Right now, there are 10 LNG terminals in China for a total capacity of 35 Mtpa, while nine more should start operating by 2016-2017, lifting the total capacity to about 60 Mtpa. The doubt now surrounding LNG prices could delay the construction of the latter, and threatens the development of ten more LNG terminals that are only in the planning stage.[16]

Nonetheless, ample room for LNG imports stil-l exists, if Petrochina's forecast proves correct, but not so huge as to justify the current rush of LNG export projects in several countries, which, given their capital costs, could only find a market in Asia, and particularly in China.

4. The US case: an update of the shale gas boom

Starting from almost zero in 2000, dry shale and tight gas production[A] has dramatically ramped up, reaching about 35 billion cubic feet per day (Bcf/d, equal to 365 Bcm per year) in July 2014 - as shown in Figure 3.

Fig. 3 – Against All Odds: US prices of natural gas and shale gas production, 2000-2014



By early December 2014, it had grown even more, and now represents more than half of the US total dry gas production of 71 Bcf/d (750 Bcm per year).

Such impressive growth has defied most projections, particularly those that repeatedly considered the shale boom a temporary phenomenon or a bubble (See Box 7).

What is more startling about the continuous growth of shale gas production is that it increased seven-fold from January 2008 to December 2014, in spite of both plummeting US natural gas prices (see Figure 4) and a falling drilling intensity for shale gas. Both factors were considered essential to sustain shale gas production.

On the price side, most observers were convinced that the majority of US shale gas resources were too expensive to develop, requiring prices of more than USD 6 MBtu. Yet, shale production registered a real boom just after the dramatic fall of US natural gas prices started in 2008, and continued to thrive even after prices plunged to their lowest levels, lingering at around USD 1.9 per MBtu in April 2012.

[A] In the current literature, the expression "shale gas," like the phrase "shale oil," has come to define resources and productions that include tight gas (and tight oil), formations that have different features with respect to shale from a geological point of view. For the purpose of this study, however, that distinction is not significant, so that I will simply use the term "shale" for both shale and tight gas.

As for drilling intensity (the number of wells drilled in a given area), it is worth remembering that each shale well output declines quickly, losing more than 50 percent of its initial production (IP, generally the average production for the first 30 days) after only twelve months of activity. Thus, to sustain and increase shale production, it is necessary to drill as many wells as possible on the same field.

Despite this sort of "shale iron law", the number of natural gas weekly active drilling rigs fell dramatically from an average of 1,500 in 2008 to slightly more than 300 in 2014.[18] This was in line with the progressive fall of US natural gas prices. Nonetheless, shale gas production continued to rise.

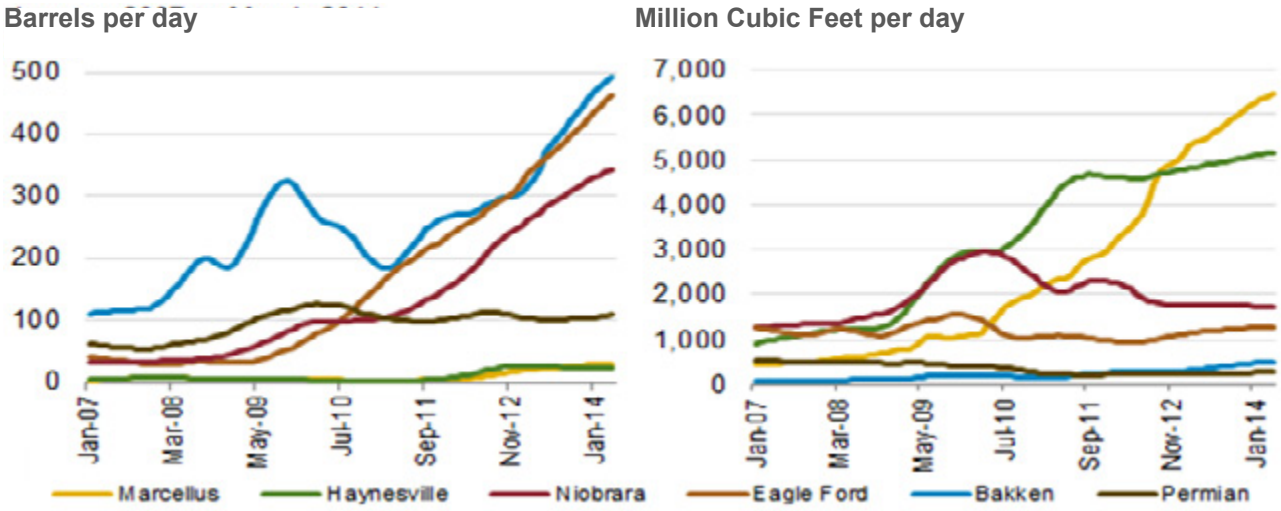
What happened?

At least two main factors prevented the grim fate of shale gas predicted by many. First was the growth from the prolific and relatively cheap Marcellus Shale, probably the largest gas field in the world. Through July 2014, Marcellus reached a production rate of 15 Bcf/d, accounting for almost 40 percent of US shale gas production: a staggering increase for a field that produced less than 2 Bcf/d in 2010.[19]

Second was the dramatic productivity increase of each new well across most US shale oil and gas plays, a consequence of better knowledge of shale and improved technology to develop it (See Figure. 4).

Fig. 4 – US monthly new-well shale oil and gas production per rig, 2007-2014

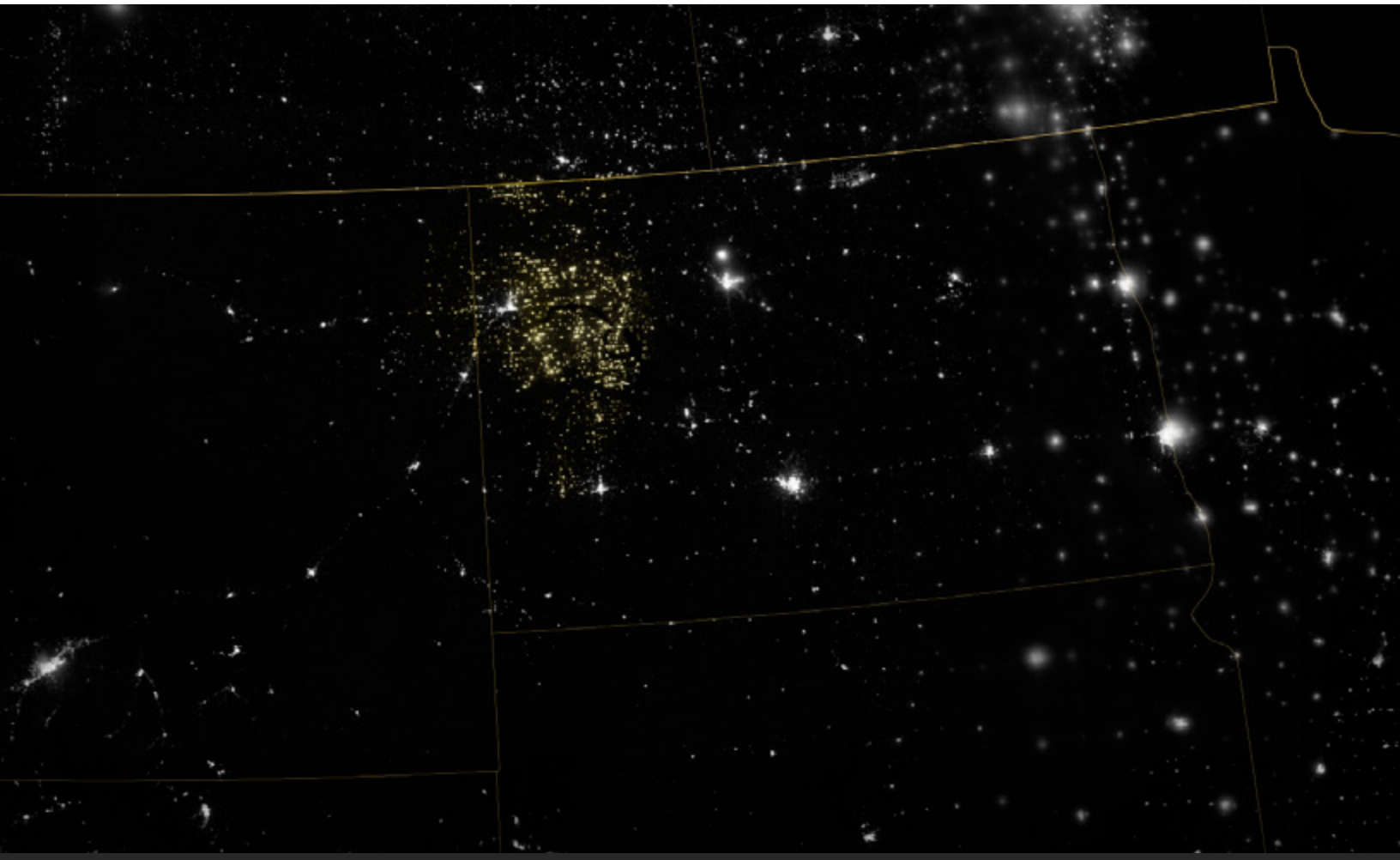
(Predominantly shale oil fields: Bakken, Eagle Ford, Permian, Niobrara. Predominantly shale gas: Marcellus, Haneysville)



Source: EIA (See Note for methodology) [20]

For example, new well production per rig in the Marcellus increased six-fold from 2010 to 2014. In the Haneysville shale, another big shale gas play, new wells are now producing four times as much as they did in 2007.[21] Similarly, in just four years, per-well productivity increased almost five-fold in the Eagle Ford (predominantly a shale oil play), and more than doubled in the oil-rich Bakken. This upward trend is also showing up in another big emerging shale gas play near the Marcellus, Utica, where new well productivity per rig jumped eight times between the beginning of 2013 and September 2014.[22]

As for shale oil plays,[23] productivity and costs vary dramatically among the different areas of a shale gas play, and the difference between owning the best acreage or the worst is what makes winners and losers.

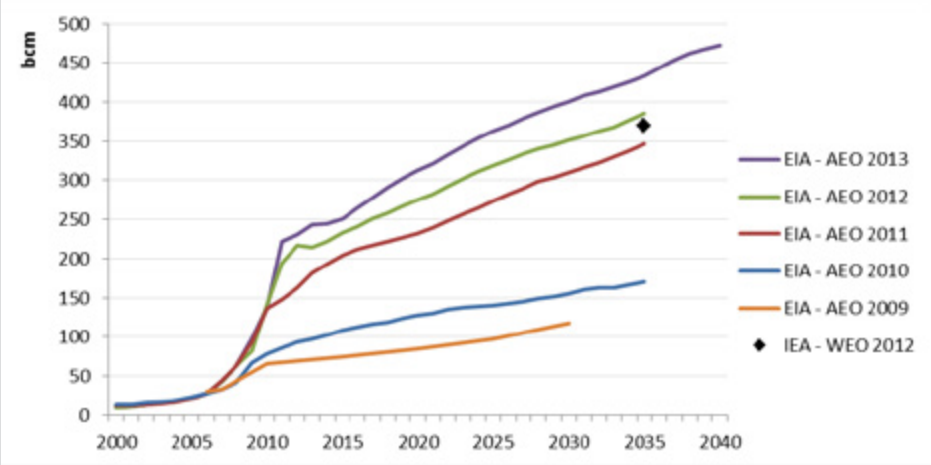


Northwestern North Dakota is one of the least-densely populated parts of the United States. Cities and people are scarce, but satellite imagery shows the area has been aglow at night in recent years, thanks to booming oil and gas activity at the Bakken shale formation. (NASA Earth Observatory; area highlighted in yellow)

Box 7 – US shale gas revolution: why most failed to understand it.

The list of agencies and experts who missed the extent of the US shale gas revolution (as well as the shale oil boom) is too long. Even the International Energy Agency (IEA) and the US Energy Information Administration (EIA) have been obliged to revise their forecast dramatically upward, after falling prey to gross underestimations, as shown in Figure 5.

Fig. 5 – EIA and IEA projections on the US Shale Gas Production, 2009-2013



Legend:
EIA-AEO (Energy Information Administration, Annual Energy Outlook)
IEA-WEO (International Energy Agency, World Energy Outlook)

Source: Richter (2013)[24]

For example, EIA's Annual Energy Outlook 2009 projected a moderate shale production increase to about 120 Bcm by 2030 in its reference case. Yet that level was reached in 2010, just one year after the forecast.[25] *By the same token, IEA's World Energy Outlook 2012 forecast a US shale gas production of 350 Bcm by 2030, a volume that was reached in June 2014.*

Analyses that underestimated the actual evolution of US shale gas production seem to have ignored the impact of improved knowledge and technology in driving up productivity and reducing per-well costs, key factors that allowed shale gas to thrive.

Traditional reasoning would have led to the belief that the shale revolution would have been impossible, relying as it did on endogenous technological innovations by small firms. It is essential to account continuously for technological change in the industry, change that requires deep knowledge and constant updating of assumptions.

These analyses, and the models used to simulate the ultimate recovery rate (URR, or also EUR, the estimated ultimate recovery) of shale resources, were based on databases of wells drilled a few years ago, when both knowledge of shale and the technology were still in their infancy. The static picture of shale that they offer does not reflect reality.

In general terms, the best players in Marcellus reported internal rates of return (IRR) of about 50 percent with a natural gas price of USD 4 per MBtu. They also reported average costs for a new well plummeting by 30 percent from 2010 on, or from an average of USD 10 million to slightly less than USD 7 million.[26] These numbers suggest that despite many doubts to the contrary, Marcellus gas can be profitable even at a price below USD 2 MBtu, at least in its more productive areas.

Of course, other US shale gas plays are not that good; they need higher prices of natural gas to ensure a decent return. This partly explains the decreasing role of the fields that originated the US shale gas revolution in the first decade of this century, e.g., the Barnett and the Lafayette, in the overall picture of the US shale gas production, at least in percentage terms.

Today, the facts seem to show that the emergence of new shale gas plays, along with improved knowledge of shale inner secrets and continuous technological advances, have allowed the best performers to overcome the price/cost challenge and thrive, making it hard to estimate at what level the price of natural gas could deflate the US shale gas boom.

Five storage tanks at the Sabine Pass regasification facility (under contstruction). June 13, 2009.
(Flickr user Roy Luck, CC license BY 2.0)

5. The US rush to export natural gas

While the jury is still out on the future of the US shale gas boom, a flurry of LNG export projects have been announced or submitted to the US Department of Energy (DOE), that must authorize natural gas exports to countries that do not have a free trade agreement (FTA) with the United States. Before exporting large volumes of methane, the United States must carefully consider several pros and cons as well as the conflicting interests of many actors.

On the one hand, exporting LNG should be a boon for gas producers, who could benefit from higher international gas prices compared to those on the domestic market. In turn, this could expand the shale gas boom in the United States, by making feasible to drill in fields or parts of fields that would not have been cost-effective.

On the other hand, the more US gas is exported, the more the domestic price of methane could increase, threatening the interests of many industrial sectors that are reviving partly because of low energy costs. Higher prices for natural gas would also hurt households and small businesses, ever a concern for lawmakers. Natural gas is also the most environmentally friendly fossil fuel, and has already played an important role in significantly reducing coal consumption in the United States. The continuation of environmentally sensitive policies by the US administration will likely spur natural gas consumption in the United States, posing an implicit cap to the LNG volumes that could actually be exported.

Furthermore, higher drilling intensity driven by increasing gas prices will add to the environmental problems that shale activity in general is already provoking in several areas of the United States, prompting a backlash against drilling for gas, which could affect its deployment.

Finally, higher domestic prices of natural gas (reflected by the Henry Hub pricing system) will turn into higher prices for US natural gas exports, thus making them less competitive, particularly if international oil prices stay below USD 90 per barrel.

Several studies have been conducted to figure out what amount of natural gas the United States could export without hurting its own domestic price significantly, starting with the study commissioned by the DOE to the EIA and NERA Consulting. The DOE study found that exports of 6 Bcf/d to 12 Bcf/d (62 to 120 Bcm per year) would have little or no impact on US natural gas prices, and deliver a net benefit to the US economy.[27] A new study commissioned by DOE will explore the impact of exporting up to 20 Bcf/d (almost 210 Bcm per year).

In spite of these studies, the number of actual US LNG export projects that will materialize in the future remains the subject of highly speculative thinking and conflicting opinions. So far, about 40 LNG export applications have been submitted to DOE, but only some of them have also been submitted to FERC. The FERC review is very expensive for companies (up to USD 100 million), but only after approval by FERC can an LNG scheme get a green light from DOE.

As of December 2014, three new US LNG export schemes to non-FTA countries have received the final approval from both FERC and DOE: they are Sabine Pass LNG trains 1-4, Freeport LNG, and Cameron LNG, totaling a capacity of 43.2 MTpa (almost 60 Bcm per year), shown in Table 1.

In addition to these, there are at least seven projects that have a significant probability of materializing. Four of them (indicated in blue in Table 1), have conditional approval from DOE and have filed for FERC review. The remaining three (indicated in red in Table 1) are in various stages of the approval process. Corpus Christi and Sabine Pass 5/6 have FERC approval, but still lack DOE conditional approval. If all these projects came online, the US total LNG export capacity to non-FTA countries would reach 118.6 MTpa (163 Bcm per year).

Table 1 – US LNG Export projects with greatest potential to come online

LNG Project	Approved Capacity (Mtpa)*	Estimated Cost (Billion USD)	Planned Early Exports	Location
Sabine Pass 1-4	**18**	**8**	**2015**	**Louisiana**
Freeport LNG	**13.2**	**14**	**2018**	**Texas**
Cameron LNG	**12**	**10**	**2019**	**Louisiana**
Sub-Total, Already Approved	*43.2*			
Lake Charles LNG	**15**		**2019**	**Louisiana**
Cove Point LNG	**7.8**	**3.8**	**2017**	**Maryland**
Jordan Cove LNG	**6**	**7.5***	**2019**	**Oregon**
Oregon LNG	**9**	**6**	**2019**	**Oregon**
Sub-Total DoE Condit. Approval, Filed for FERC	*37.8*			
Corpus Christi LNG	**13**		**2019**	**Louisiana**
Sabine Pass 5-6	**9**		**2019**	**Louisiana**
Golden Pass LNG	**15.6**	**10**	**2019**	**Texas**
Sub-Total, Significant Potential	*37.6*			
Total	**118.6**			

**Including South Dunes Power Plant and Pacific Connector pipeline*

In addition to these projects, there are six more that have filed both for DOE and FERC. It is probable that even the most likely projects to come online may never materialize for several reasons. Even the complete approval by DOE and FERC is no guarantee. As the head of the US Energy Information Administration, Adam Sieminski, noted, "Just as in the case of all the LNG import facilities that were permitted and never built, there are a lot of LNG export facilities that could receive permits and might never get financing and be built."[28] Section 6 focuses on the reasons why the final count of US LNG export capacity could be much lower than current projects seem to indicate.

Preserving an affordable capital cost structure is essential for the future of US LNG schemes. Indeed, most of the LNG "off-load" agreements signed so far are based on the "tolling-fee" formula, which means that they may not imply actual sales of natural gas.

For buyers, they represent an option to buy in case the price of US natural gas remains competitive. Should this not be the case, they could opt not to buy natural gas while paying for the liquefaction capacity that they have contracted, and turn to other, cheaper sources of supply. To make this option attractive, however, the tolling fee must be a convenient one for the buyers. In turn, this requires rigorous financial cost planning by the potential owner of an LNG plant.

Other reasons make the above-mentioned US LNG exports projects attractive.

First, they are well poised in terms of capital costs, because they are to be built in existing regasification terminals, most of which were constructed and completed just a few years ago when the mainstream view was that the United States would need to import gas in large volumes – a paradigm shift that bears a cautionary message about the current enthusiasm to build up export capacity (See Box 8).

Box 8 – Between Two Extremes: The US Shift from Importing to Exporting Gas

From the 1980s, the United States witnessed a decline of its domestic natural gas production that seemed irreversible. For a long time after the start of the shale gas revolution in the early 2000s, no one expected that shale and tight gas formations could change the situation. Alan Greenspan, then chairman of the Federal Reserve, epitomized this attitude when he testified before Congress in 2003, "My own judgment is that there is probably no real alternative here but to resort to international sources of energy, because there is no way we can be self-sufficient."[29] *Greenspan's view was shared by the majority of US experts, at least until the end of the first decade of the new century.*

Now that the view has been upturned, the fate of the LNG import terminals represent a reminder of how easy it is to overspend and overbuild based on incorrect views of the future. This reminder should act as a red flag about overbuilding export capacity.

Second, US LNG plans can also count on a large supply of skilled people at a reasonable cost, a factor that some other areas of the world do not enjoy.

On paper, these factors allow for a unit capacity cost per million tons of capacity ranging between USD 700 and USD 950, which implies a unit cost of about USD 3.20-USD 4.20 per MBtu, depending on several assumptions – as shown in Box 9.

These costs are consistent with those assumed, for example, by Cheniere Energy, the first company to obtain full approval for its project, the Sabine Pass 1-4 LNG. According to the company, the first trains of Sabin Pass have a capacity cost which allows Cheniere to set its capacity price to buyers at USD 3.5 per MBtu.

Together with the other costs connected with the LNG chain, this would translate into a delivery cost before regasification of about USD 9.10 per MBtu to Europe, and USD 11.10 per MBtu to Asia, depending on certain assumptions, shown in Table 2.[30]

So far, Cheniere has applied the same scheme (USD 3.50 tolling fee covering capacity costs and a natural gas price at 115 percent of Henry Hub) to all supply agreements signed with LNG buyers of the company's additional export project, Corpus Christi.[31]

Clearly, any increase or decrease of the US Henry Hub price changes this projection significantly. Nevertheless, the low capacity cost creates a significant advantage for US LNG export projects compared to the rest of the world, as we will see below.

Table 2 – Cheniere's calculation of Sabine Pass LNG train 1 delivery costs to different areas

(U.S. Dollars per MBtu)

Cost	America	Europe	Asia
Natural gas	**4.60**	**4.60**	**4.60**
Capacity	**3.50**	**3.50**	**3.50**
Shipping	**0.50**	**1.00**	**3.00**
Delivery Cost	***8.60***	***9.10***	***11.10***

Cheniere's assumptions:
Henry Hub price: USD 4 MBtu
Oil price: USD 100 per barrel
LNG price: 11% to 15% of oil price
Natural gas cost: 115% of Henry Hub price

Box 9 – LNG Capacity Cost

For the purpose of this study, I calculated the unit capacity costs per MBtu considering three main components:

1. *Operations and maintenance costs, which vary widely, between USD 0.20 and USD 0.30, depending on the specific location and conditions of the labor market;*
2. *Capital costs, which vary even more dramatically depending on location, as shown in the study;*
3. *Fuel use costs, which vary with natural gas prices over time.*

I annualized the investment costs per Mtpa of each LNG project considered in this study, assuming a plant life of 25 years, which corresponds to the initial contractual period considered by the owners of that plant for selling LNG to their customers. Then I applied a 75 percent utilization factor to the capital cost per MBtu of LNG capacity, considering that 1 ton of LNG equals to 52 MBtu. I considered that about 9 percent of LNG is burned off in the process of liquefaction. Finally, I assumed a 10 discount rate.

6. How far could US LNG export actually go?

Whereas the US LNG schemes appear to be the most competitive among the flurry of new LNG projects globally, there are several risk factors which may significantly trim actual US export capacity by 2020.

First, capacity costs usually tend to increase over time as more liquefaction trains are actually constructed, particularly if there is a spike in the demand for skilled people and services. As we will see in Section 7, one of the main factors driving Australia's LNG huge cost overruns has been the rush to build seven big projects at the same time, creating shortages of people and skills. Specific environmental and safety requirements may also add to the costs.

The Gulf of Mexico area, where most US LNG schemes should materialize, holds the greatest concentration of skilled labor and engineering companies in the world. Furthermore, a few LNG plant proponents have apparently shifted the risk of cost overruns to the contractors. But most have not, and in the next few years, the Gulf of Mexico area will be home to a flurry of big petrochemical projects competing for the same skilled people and construction services. This will create additional pressure on costs.

At this time, insights from companies and financial institutions involved in LNG projects indicate that the most likely structure will impose a capacity cost of USD 4.50-5 per MBtu on most export schemes, which could threaten their competitiveness. This possibility, combined with the recent fall of oil prices, is creating another risk for US LNG exports, viz., the difficulty of finding adequate financial support, as stressed by Sieminski (See Section 5). Industry insights reveal that this risk is already affecting several projects.[32]

The recent fall of oil prices heralds a wider element of risk for US LNG exports, the relationship between oil-indexed LNG and hub-based LNG. This is a complex equation, with several moving factors.

For example, Cheniere Energy originally estimated the delivered price of its gas to Asia at USD 11.90 per MBtu (excluding regasification costs), based on a Henry Hub price of USD 4 per Mbtu, oil (Brent) at USD 100 per barrel, and a relatively high 15 percent oil slope (the factor used to convert per-barrel oil prices to per-MBtu LNG prices).

All other factors being equal, with Brent around USD 80 per barrel, oil-indexed LNG contracts are competitive with US LNG even in Asia. If the US natural gas price rises, or US capacity and shipping costs increase while Brent stands at around USD 80 per barrel, US LNG loses most of its original attractiveness.

In this framework, US LNG exports to Asia could face an additional hurdle. The LNG schemes most likely to materialize in the near future are located in the Gulf of Mexico with the exception of Cove Point. Meanwhile, the two schemes on the US West Coast (Oregon), among other things, need Canadian gas to come on line, a major factor of uncertainty (see Section 8).

Future shipments from Gulf of Mexico plants would usually go through the Panama Canal, the quickest and cheapest route to Asia. When the widened Canal reopens (probably in 2016) after its expansion, it will allow only six vessels a day in each direction, regardless of type (including dry

bulk, container carriers, and cruise ships). This could create a bottleneck for US LNG exports, limiting the availability of the Canal, and imposing higher shipping costs and delivery delays. The alternatives to the Panama Canal are to go through the Suez Canal or around the Cape of Good Hope, which adds 12-13 days to the shipping time and much more cost.

As for exporting gas to Europe, several doubts loom large about European capacity to absorb enough natural gas from the United States. This stems not only from pricing considerations, but also from the sluggish demand for natural gas across Europe, which leaves less room for additional gas to the region, not to mention the attractiveness of higher prices in Asia for US LNG exporters.

Finally, it is highly probable that, faced with a significant amount of US LNG going to Europe, Russia, Algeria and other big European suppliers of natural gas might start a price war against American gas.

Consequently, unless one can expect that the European gas price will increase substantially, investors in US LNG export schemes need to be careful about assuming that Europe will be a big market for US natural gas exports.

For these reasons, it is unlikely that more than five or six LNG export plants will come online by 2020, implying that final US LNG export capacity to non-FTA countries will hardly reach more than 60-70 MTpa by the end of this decade. This will make it difficult for the United States to change the structure of the different international gas markets significantly.

LNG Tanker Alto Acrux leaving Darwin, Australia with the assistance of three tugs after loading at Wickham Point. June, 2012. *(Flickr user Ken Hodge, CC license BY 2.0)*

7. The case of Australia

Since early in the first decade, Australia has witnessed huge gas discoveries and frantic activity to develop them.[14] Until recently, the total cost of producing natural gas was more competitive than the US case, with the domestic price in 2010 sitting at less than USD 2 per MBtu.[34] In the last few years, however, several factors have put pressure on costs, along with the general inflation that has hit the exploration and production sector globally since the beginning of the century.

More than 90 percent of Australia's conventional gas resources are located in the country's northwest marine region, where some of the world's most pristine and biologically diverse marine ecosystems overlie oil and gas reserves. This unique ecosystem has increased environmental worries and tightened legislation, in turn imposing higher costs, particularly after the 2009 blowout of a wellhead located 250 km off the Kimberley coast. The incident turned into the worst offshore oil spill in Australia's history, resulting in 10 weeks of continuous release of oil and gas into the Timor Sea.

The remaining portion of already producible gas reserves is made up of coal-bed methane (CBM), an unconventional source of natural gas, with which Australia is highly endowed. Located in the northeastern province of Queensland, a large part of CBM reservoirs has proven trickier to develop than expected. In particular, they require many more wells to be drilled to reach and maintain targeted levels of production. Clearly, if the number of wells to be drilled increases substantially over a project lifetime – as most companies now admit – upstream costs will grow as well.[35]

In addition, the quantity of economically exploitable CBM reserves is not big enough to allow for hiccups or lower-than-expected recoverability.[36] Lower-than-expected production is already forcing future LNG operators to secure gas at oil-indexed prices from third-party companies to feed their LNG export plants. At the same time, environmentalist groups and farmers are strongly opposing CBM exploitation, posing an additional threat to the extent of its development.

Whatever the future, the cost of Australian conventional and unconventional natural gas and the sustainability of its large-scale production are part of the wider problem affecting all new LNG schemes in the country, that is, the explosion of costs.

Australia is currently adding almost 62 Mtpa of nominal LNG capacity, thanks to integrated projects where upstream developers are also the promoters and operators of LNG facilities. The latter are already under construction (See Table 3), even though their development could easily face significant delays, or a partial adjustment. This uncertainty stems from the astronomical costs incurred by some Australian LNG schemes, the most expensive LNG projects ever.

On paper, the highest unit cost for an integrated project (upstream and midstream development) has been for the Ichthys LNG project, operated by Japan's Inpex, whose overall budget was approved in early 2012 at USD 4,000/ton of capacity (total cost of USD 34 billion, capacity of 8.4 Mtpa), although that includes a bonus of up to 100,000 barrels per day of associated condensate and 1.6 million tons of liquefied petroleum gas.[37]

Close behind are Pluto LNG, operated by Australian Woodside, with a unit cost estimated at

USD 3,465/ton;[38] Gorgon LNG, operated by Chevron, with a unit cost estimated at USD 3,461/ton (total capacity of 15.6 Mtpa, making it the most expensive LNG scheme ever realized globally, at USD 54 billion); and Wheatstone LNG, operated by Chevron, at USD 3,150/ton (total capacity 8.9 Mtpa).[39]

Table 3 - Australian and Papua New Guinea LNG Projects under Construction

Project	Partners (%)	Capacity (Mtpa)	Start-Up Target
PNG LNG (Papua New Guinea)	Exxon (33.2) Oil Search: (29) PNG Government (16.8) Santos (13.5) Nippon Oil (4.7) PNG Landowners (2.8)	6.9	May 2014 (started)
Gorgon (Australia)	Chevron (47) Exxon (25) Shell (25) Osaka Gas (1.25) Tokyo Gas (1) Chubu Electric (0.4)	15.6	Mid-2015
QC LNG (CBM-based) (Australia)	BG (50) CNOOC (50) Tokio Gas (5 in train 2)	8.5	End-2014
GLNG (CBM-based) (Australia)	Santos (30) Total (27.5) Petronas (27.5) Kogas (15)	7.8	2015
AP LNG (CBM-based) (Australia)	Origin (42.5) ConocoPhillips (42.5) Sinopec (15)	9	2015
Prelude (Floating LNG)	Shell (67.5) Inpex (17.5) Kogas (10) CPC (5)	3.6	2017
Wheatstone (Australia)	Chevron (64.14) Apache (13) Kupfec (13.4) Tepco (8) Kyushu Electric (1.46)	8.9	2016
Ichthys (Australia)	Inpex (63.445) Total (30) Tokyo Gas (1.57) Osaka Gas (1.2) Chubu Electric (0.735)	8.4	End-2016
Pluto LNG (Australia)	Woodside (90) Kansai Electric (5) Tokyo Gas (5)	4.3	July 2017

On average, more than 50 percent of these costs include only the construction of liquefaction capacity and related services (storage, pipelines, etc.). This should raise a red flag.

The 25-year amortization period I used as a reference in this study implies a unit capacity cost of around USD 9-11 per MBtu for the above-mentioned projects. If we add the cost of natural gas, the shipping of LNG, and other minor costs, total delivery costs for LNG from Australia could easily exceed USD 15 per MBtu before regasification, a range that matches the very high LNG prices in Asia after 2011.

In the recent past, this would imply at best "skinny margins" for Australian LNG operators, as pointed out by Peter Coleman, CEO of Woodside Petroleum, one of the biggest Australian integrated operators.[40] But after the plunge of oil and LNG prices in Asia in the second half of 2014, the Australian LNG chapter risks becoming one of the worst investment stories of the last few decades in the oil and gas sector.

The situation has already forced several companies to step back from planned projects. In 2013, Woodside stepped away from plans to build an LNG project on the Kimberley coast, at a cost that would have topped USD 80 billion. Shell and Petrochina's jointly owned Arrow Energy has indefinitely deferred its USD 20 billion-plus coal seam gas-based LNG project in Queensland. Planned expansions of Chevron's USD 54 billion Gorgon project and of BG Group's Queensland Curtis project have been put off. In the last few weeks, Santos and its French partner GDF Suez have also decided not to go ahead with their proposed Bonaparte floating LNG project off Darwin, in the Northern Territory, due to high costs at present and the potential for further cost blowouts.

What went wrong?

Australian LNG costs have surely outpaced the general inflation experience of the worldwide exploration & production sector. This reflects both the peculiar conditions of the Australian market and some sort of inability of oil and gas companies to understand them fully and address them.

Several studies, including Brian Songhurst's "LNG Plant Cost Escalation," have shown that the main components of Australia's cost inflation have been the appreciation of the Australian dollar against the US dollar since 2009, and the ballooning cost of labor. The combination of the two represents more than 50 percent of this inflation.[41]

Labor costs have been one of the most striking factors of Australian inflation. The combination of the union struggle to increase payrolls, low labor productivity (also a result of union strength), and the need to attract specialized technicians from abroad, pushed the Australian oil and gas worker's average salary to USD 163,600 by 2013, 35 percent more than oil and gas workers in the United States and almost double the global average.[42]

While the Australian dollar has finally stopped appreciating, the problem of labor costs continues to pose a major challenge to the economic feasibility of several Australian LNG projects, due to the firm and growing demands by Australian unions and the tightness of the supply of skilled, specialized workers.

Other important contributors to Australian inflation include underestimating the costs for steel and other materials, and for basic infrastructure and facilities (including power, water, routes, pipes, etc.) to be built in the middle of nowhere (approx. 20 percent). The attitude by companies working in a given area not to cooperate on the construction of infrastructure that could be shared also played a role. Indeed, the fact that seven big LNG projects were started almost at the same time with no cooperation among the companies escalated costs.

Looking beyond Australia, LNG capacity costs are likely to skyrocket in all those countries where projects are in isolated areas, where there is no infrastructure, no skilled workers, and where you need to import everything, from steel to people. This is the case, for example, for Exxon's Papua New Guinea LNG (PNG LNG) project, whose overall cost unexpectedly went to USD 19 billion for an annual capacity of 6.6 million tons, or USD 2,878/ton.[43]

The future sustainability and profitability of Australian LNG depend essentially on two factors: a high oil price and a voracious appetite for natural gas in Asia, particularly in China and Japan. Both factors, however, are surrounded by uncertainties.

As we have seen in Section 6, the fall of oil prices makes oil-indexed LNG sources (like Australia) more competitive. On the other hand, it eats away the already "skinny" margins for exporters and in most cases makes several Australian LNG schemes completely unprofitable.

Most Australian LNG projects considered here are under construction and set to start in the next few years. Thus it is improbable that lower oil prices will stop their completion. As they start working, they will likely contribute to the gas supply at whatever the price at the time, because companies cannot help selling gas to cover operating costs, even if they do not recover capital costs. This scenario poses a major threat to the feasibility of expanding LNG capacity in Australia beyond those trains already under construction.

A prolonged phase of lower oil prices could also further delay the overdue confrontation between buyers and sellers of LNG on the pricing formula. Over the last few years, the oil-price indexation of LNG has been challenged ever more strongly by Asian buyers but stoutly defended by LNG sellers, whose main argument was that without the indexation, most LNG integrated projects would never materialize, thus leading to a shortage of gas. Both positions, however, referred to a world where oil cost USD 100 per barrel oil or more. Now that the situation has changed, it is difficult to envisage how the confrontation may evolve.

Whatever the scenario, the truth remains that most Australian LNG export projects should not be taken for granted. In any case, the high cost of Australian LNG limits it to the Asian region, without its contributing to the overall liquidity of the global gas market.

8. The cases of Canada and Mozambique

In addition to the United States and Australia, several other countries and regions are either building or planning the construction of new LNG export capacity. In most cases, such projects are still on paper, lacking any upstream cost estimates or front-end engineering design (FEED) data, which would allow for reasonable estimates of their overall costs.

For their potential impact on the liquidity of the global LNG market, however, two countries deserve special focus: Canada and Mozambique.

Canada has huge natural gas resources, unlocking which is critical to creating new export alternatives to the only one existing today, the United States. This requires the country to build a significant LNG export capacity.

In the last few years, fifteen LNG export projects applied for an export license, a necessary but insufficient step to start an LNG project in Canada. So far seven of them have received a license. Encompassing a total export capacity of around 57 Mtpa,[44] the materialization of these projects could immediately make Canada one of world's biggest LNG producers. However, for several reasons, Canada's LNG ambitions are likely to be frustrated in this decade.

First, the vast majority of Canadian LNG projects is expected to be located in the western province of British Columbia, a politically and environmentally sensitive region, where any energy scheme appears difficult to materialize.

In particular, the traditional opposition to oil and gas projects by the First Nation communities (the aboriginal tribes that have inhabited Canada for centuries) so far has represented a major obstacle for any pipeline or LNG scheme. The situation worsened for LNG after the June 2014 ruling by Canadian Supreme Court, which gave the country's indigenous populations unprecedented control over their ancestral lands, affirming that "First Nations have legal title to their ancestral lands unless these rights have been signed away in formal treaties."[45]

Making things trickier, all LNG selected sites in British Columbia are green-field and far from the nearest source of basic supplies. They need a huge infrastructure to be built from scratch, including gas pipelines to cross two mountain ranges to connect gas producing areas to the northeast with the ports of Prince Rupert and Kitimat.

So far, the companies seem to have underestimated both the impact of these hurdles on the capital costs of Canadian LNG schemes, and the inflation spiral that would likely accompany the development of those schemes. For example, Shell's LNG Canada was originally projected at USD 12 billion for two 6-million ton/yr trains. Recently, according to Shell, the estimated price has ballooned to "USD 24 billion for two trains and USD 40 billion for four trains".[46]

The most likely range for Canadian projects to deliver future LNG profitably is at USD 12-13 MBtu, but this figure could increase once actual construction costs emerge.[47] For this reason, the fall of oil prices could undermine most Canadian LNG indefinitely, because, except for Goldboro LNG, all Canadian LNG export projects are oil-indexed, the formula that, according to producers, was key to ensuring adequate long-term returns in a world of high oil prices.[48]

No company involved in developing LNG export projects in Western Canada has yet taken a final investment decision, reflecting the huge difficulties of reconciling all the conflicting aspects of such a complex situation.

In fact, the LNG scheme most likely to materialize, the 10-MTpa Goldboro LNG, is on the East Coast, in Nova Scotia. It has already secured a long-term customer (German E.on) for 20 years, starting in 2019, but had not received an export license as of November 2014. This is also the only scheme whose selling price formula is not oil-linked.

To circumvent some of the problems affecting British Columbia, Canadian natural gas developers could send their natural gas to the US west coast, where it could be liquefied and shipped to Asia. But the fate of Oregon's LNG schemes seems very uncertain in this decade.

Even the long-awaited announcement of a tax-break for British Columbia LNG projects left investors cold. One of the largest planned LNG projects, Prince Rupert LNG (21.6 MTpa capacity), has been officially put on hold "likely until the next decade," according to the project leader, UK British Gas (BG).[49] Because of these factors, it is highly improbable that Canada will contribute to the growth of global LNG export capacity by 2020, except perhaps for some volume from Goldboro LNG.

Looking to Mozambique, in the last few years, more than 150 trillion cubic feet (or more than 4,200 Bcm) of recoverable gas reserves have been discovered in the Rovuma Basin off the country's northeastern coast in two main blocks, Area 1 and Area 4, respectively operated by Eni of Italy and Anadarko Petroleum Corporation of the United States. The future could bring additional discoveries, turning the area in one of the biggest gas finds in the world.

Whereas commercial, proven reserves have yet to be properly evaluated, upstream costs seem to be competitive at about USD 1 per MBtu. The problem with Mozambique's natural gas is the complete lack of basic infrastructure and skilled people, aggravated by a difficult geography and a savage natural environment. Coupled with the crowded demand for LNG essential tools that promises to raise even more the cost of building infrastructure, this seems to portend very high costs for the country to materialize its LNG ambitions.

Both Eni and Anadarko aim to export their first LNG cargoes by 2018-2019 partly by combining their assets and future facilities, but not their marketing. However, to confront the difficulties of Mozambique, the companies have presented different schemes for developing LNG.

Anadarko relies on a more traditional project to build two 5 Mtpa trains at a shared onshore site. ENI is committed to just one train, and has proposed three separate 2.5 Mtpa floating LNG vessels, one of which (*Coral FLNG*) would be dedicated to Eni exclusively.

Onshore LNG development in Mozambique would need special legislation for the integrated upstream, midstream and downstream elements of the project. According to Eni, FLNG would avoid several legal, regulatory, and logistical hurdles that could delay significantly any onshore project and severely affect its costs. However, the Eni FLNG scheme is based on commercially untested technology.

With the problems surrounding a detailed engineering of any investment decision, the possibility

of Mozambique becoming an LNG exporter by the end of this decade or even early in the next one seems to be very thin. The same problems make it difficult to estimate a reliable cost structure for Mozambique's LNG, without making the mistakes witnessed in Australia.

In August 2014, Nelson Ocuane, the president of the Mozambique's state oil company ENH (a partner of both Anadarko and Eni) declared that the initial investment to build 20 Mtpa of LNG capacity tops USD 30 billion. Ocuane did not provide a detailed breakdown of that estimate, but it did not include upstream costs, and seemed only to refer to the development of the northern ports of Pemba and Palma, where a giant logistics base and LNG production plants are planned.[50]

Ocuane was the first to put an overall price tag on Mozambique's first stage of LNG infrastructure development, but his early estimate probably does not include that costs that oil and gas companies need to tackle, such as the relocation of entire villages, the cost of attracting specialized people, and the cost of financing megaprojects in a country that lacks everything.

Other controversial aspects of the timing and profitability of Mozambique's future LNG concern the so-called domestic market obligation (DMO), legislation requiring that 25 percent of a company's production be used domestically, and the will of the government to impose upon companies the use, to a certain degree, of both local people and contractors, to generate employment and develop local businesses. All this must be created from scratch.

These elements suggest that when available for export in form of LNG, Mozambique's gas will not be cheap, and that it will have to compete with Australia and Canada for the Asian market.

BC Premier Christy Clark and Rich Coleman, Minister of Natural Gas Development witnessed the signing of a joint venture agreement to develop a proposed liquefied natural gas export project, April 30, 2014.
(Government of British Columbia)

9. Is floating LNG a real alternative?

As we have seen in the cases of Australia and Mozambique, companies looking to monetize remote offshore gas fields are increasingly betting on Floating LNG (FLNG) vessels. Currently, none exist, but three are under construction and eleven are in the pipeline with a combined capacity of around 57 Mtpa per year.[51]

It is likely that only a few of these projects will materialize, for several reasons. Among them, FLNG technology remains commercially untested, the few data about the cost of such vessels indicates that they will be very expensive, and very few yards and engineering firms are capable of building what could be the biggest ships on the planet.

The three vessels whose construction is under way are Malaysian state Petronas' 1.2-Mtpa *PFLNG* 1, FLNG Pioneer Royal Dutch Shell's 3.6-Mtpa *Prelude*, and Pacific Rubiales' 500,000-Mtpa Caribbean FLNG. *Caribbean FLNG* is expected on line in early 2015, *PFLNG* 1 in the first half of 2016 and Prelude in 2017.[52]

When it comes online in 2017, Prelude will be the heaviest and biggest floating vessel ever built at 600,000 tons of displacement (actual mass), about six times heavier than the largest passenger ships or aircraft carriers in service.

By comparison, *Allure of the Seas* and her sister ship *Oasis of the Seas* hold the record as the largest passenger ships ever constructed, with a gross tonnage of more than 225,000 metric tons. They displace approximately 100,000 metric tons (110,000 short tons), slightly less than the American *Nimitz*-class aircraft carriers, the largest warships in service.

Even Shell's Prelude would be smaller than Exxon Mobil and BHP Billiton's proposed *Scarborough FLNG*. The Anglo-Dutch company indicated that its vessel will have a capacity of 3.6 Mtpa and is expected to cost between USD 10.8 and USD 12.6 billion, or USD 3,000 to USD 3,500 per annual ton. Using that cost structure, *Scarborough LNG* would have a proposed capacity of 6-7 Mtpa, and would likely cost no less than USD 18-24 billion.

Both cost hypotheses have yet to prove correct, and given the challenge of building such huge and untested floating structures in a period of high costs, it is likely that the final cost will be higher than planned. This is reinforced by the fact that there are only a handful of yards that can handle vessels of that size, and few engineering companies that can face the daunting requirements of their design and construction, e.g., withstanding the most intense cyclones (as in the case of *Prelude*). These two factors mean that there is now a huge demand and a limited supply of engineering and construction capacity. This alone sends costs ever higher. Finally, the technology has yet to work in practice, and this may lead to adaptation and changes during construction, which may further escalate costs.

10. Conclusions

Even a prudent and skeptical view of the evolving global gas market cannot help but recognize that soon the world will witness the largest increase ever of LNG export capacity.

Yet many doubts remain about the actual extent of such an increase.

Most LNG planned additions are based on very high upstream and midstream costs that would make them hardly profitable even in high price scenario. The fall of oil prices in the second half of 2014 risk now to kill most of them, or postpone indefinitely their materialization.

In the foreseeable future, the LNG export additions that appear to be more cost-competitive are those in the United States. This stems from a combination of lower than generally estimated upstream costs for shale gas, lower capital costs for infrastructure build-up. Making them attractive is also the almost total flexibility to ship gas to any destination and the "tolling-fee" nature.

Nevertheless, many clouds linger over US LNG export growth in the next decade. In Asia, lower oil prices could make oil-indexed new LNG supplies such as Australia's competitive. Low oil prices could also make traditional supplies to Europe cheaper, by pipelines or LNG. In this framework, the ability of the United States to free Europe from its dependence on Russian gas seems to be very limited. This aspect is further reinforced by two elements: on the one hand, the Asian market will always represent a more rewarding outlet for US LNG financially, so it will absorb most future US LNG shipments; on the other, traditional suppliers to Europe could mount a moderate price war to keep the United States out of the European market, particularly if oil prices were to rebound.

US LNG could have a significant impact in Europe if the latter could rely upon a significant strategic natural gas reserve to be used in case of emergency, using gas bought during periods of oversupply. But Europe does not have that reserve, so its flexibility is constrained.

Finally, regardless how optimistic or pessimistic one may be about the continuation of the shale gas revolution, the possibility remains that US shale gas production will not be able to feed growing exports of natural gas, either for environmental reasons (for example, a ban on extending fracking to several areas of the United States), or for having reached the natural limits of shale exploitation at reasonable costs.

The picture is gloomier for other new LNG export schemes.

Australian LNG has turned into one of the worse investment cases of the last decades in the oil and gas sector.

Huge cost overruns have made Australian LNG unprofitable at current oil prices – being all Australian gas oil-indexed. This will probably stop the rush to build additional trains of liquefaction in the country. However, cheaper oil oil will also create a paradoxical situation: several Australian projects are already in an advanced state of completion, Consequently, they will come online and their capital costs will be considered as sunk costs. At that point, sellers will only need to cover operating costs to keep going, and their gas could be competitive with US LNG on the Asian market. Thus, Asian buyers could gain the upper hand in dealing with competing sellers,

and finally negotiate a pricing formula that may better suit their perceived long-term interests.

Also the yet-on-paper Canadian and Mozambican potential LNG exports seem to be too expensive to cope with the current market situation. This is likely to freeze their materialization till the next decade.

For all these reasons, although LNG trade will increase as never before, it will not increase enough to compete with the international gas trade via pipelines. The most likely increase of LNG would be in the region of 100 to 130 MTpa, or much less than expected. What's more, due the high costs of new LNG export additions, the largest part of new exports will serve just the Asian markets, which historically have registered a higher price than other markets.

In this decade at least, this will deprive the global gas market of a sufficient level of liquidity, and it will cause international gas markets to retain their regional nature.

List of Abbreviations

Note: In order to simplify the text for non-expert readers, I simplified the acronyms of some measurement units. For example, I used MBtu for Million British Thermal Units, instead of the more common MMbtu or mmBtu.

Bl	Barrel
Bcf	Billion cubic feet
Bcm	Billion cubic meters
Btu	British thermal unit
Boe	Barrel of oil equivalent
CNPC	China's National Petroleum Company
EIA	U.S. Energy Information Administration
Eur	Estimated ultimate recovery
DOE	U.S. Department of Energy
FERC	U.S. Federal Energy Regulatory Commission
FTA	Free Trade Agreement
IEA	International Energy Agency
IRR	Internal rate of return
LNG	Liquefied natural gas
MBtu	Million British thermal units
Mcf	Million cubic feet
MTpa	Million metric tons per annum
Tcf	Trillion cubic feet
Tcm	Trillion cubic meters
ToP	Take or Pay
URR	Ultimate recovery rate

Main Conversion Factors

1 Cubic Meter = 35.31 Cubic Feet

1 Cubic Meter = 0.0362 MBtu

1 Cubic Feet = 0.0283 Cubic Meters

1 Cubic Feet = 0.01 MBtu

1 Billion cubic feet per day= 10.4 Billion cubic meters per year

1 MBtu = 1 Mcf

1 Boe = 5.8 MBtu

1 Boe = 152.2 Cubic Meters

1 Boe = 0.105 Tonnes LNG

1 Boe = 0.243 Cubic Meters LNG

1 Metric Tonn LNG = 1,380 cubic meters

1 Metric Tonn LNG = 48,700 cubic feet

1 Metric Tonn LNG = 52 MBtu

Notes

[1] For a wider view of natural gas conversion factors, see: http://www.platts.com/conversion-tables

[2] International Gas Union (IGU), World LNG Report – 2014 Edition. See: http://igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf.

At the end of 2013, 60% of the global fleet had a capacity between 125,000 and 149,000 m3, making this the most common class of LNG carrier. However, ships in the 150,000 m3to 177,000 m3range have dominated new-build orders over the past decade. These vessels currently make up 21% of the global fleet, a share that is expected to grow rapidly in the years ahead. The largest category of LNG vessel is the Q-Series, accounting for 13% of the vessels in operation in 2013. The Q-Series is composed of both Q-Flex (210,000-217,000 m3) and Q- Max (261,700-266,000 m3) vessels. Data does not include small vessels, with a capacity of less than 18,000 m3.

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[4] IGU (2014)

[5] International Energy Agency (IEA), 2014 Medium-Term Gas Market Report. See: http://www.iea.org/w/bookshop/add.aspx?id=473

[6] IGU (2014).

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[9] "Keep LNG Costs Down or Coal Wins, Says IEA." WGI. June 4, 2014. See:http://www.energyintel.com/pages/eig_article.aspx?DocId=849403

[10] "China Delays Gas Price Hike." WGI, April 16, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?DocId=844089

[11] Of the four planned Central Asia-China gas pipelines, only two are in operation, with a combined capacity of 30 Bcm/yr. An additional 25-Bcm/yr pipeline should start operations in 2014, while the fourth line should start operations in 2018. See: WGI. "Chinese Giants Split on LNG Outlook." May 28, 2014. http://www.energyintel.com/pages/eig_article.aspx?DocId=848572

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[13] Author's interviews, August-September 2014.

[14] "China Gets Serious About Gas Price Reform." WGI, Aug. 25, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?DocId=857687

[15] "China's LNG Construction Dilemma." WGI, Sept. 3, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?DocId=859014

[16] Ibidem.

[17] EIA Natural Gas Weekly Update for week ending December 3, 2014. See: http://www.eia.gov/naturalgas/weekly/

[18] Baker Hughes. North America Rotary Rig Count: January 2000 Current. See: http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother

[19] EIA. Drilling Productivity Report, August 2014. See: http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

[20] EIA's methodology for estimating new-well production per rig uses several months of recent historical data on total production from new wells for each field divided by the region's monthly rig count, lagged by two months. A new well is defined as one that began producing for the first time in the previous month. Each well belongs to the new-well category for only one month. Reworked and recompleted wells are excluded from the calculation.

[21] EIA. Growth in U.S. hydrocarbon production from shale resources driven by drilling efficiency. March 11, 2014. See: http://www.eia.gov/todayinenergy/detail.cfm?id=15351

[22] EIA. Drilling Productivity Report, September 2014, p.8. http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

[23] Ibidem.

[24] Richter, Philip. "From Boom to Bust? A Critical Look at US Shale Gas Projections." DIW Berlin, Discussion Paper 1338 (2013), p.7.

[25] Ibidem, p. 7.

[26] Author's processing of company presentations by: Anadarko Petroleum Corporation, Cabot Oil & Gas, Chesapeake Energy, Noble Energy, etc…

[27] In August 2011, DOE engaged EIA and NERA Economic Consulting (NERA) to conduct a two-part study of the economic impacts of LNG exports. EIA was requested to assess how prescribed levels of natural gas exports above baseline cases could affect domestic energy markets. Later on, NERA was requested to incorporate the forthcoming EIA case study output from the NEMS model into NERA's general equilibrium model of the U.S. economy. NERA analyzed the potential macroeconomic impacts of LNG exports under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports. After publishing the two studies, DOE published a Notice of Availability (NOA) of the EIA and NERA studies inviting public comment on the Study, and stated that its disposition of the present case and 14 other LNG export applications then pending would be informed by the Study and the comments received in response thereto. For the EIA/NERA study see: US DOE. 2012 LNG Export Study, 77 Fed. Reg. 73,627, (Dec. 11, 2012). See: http://energy.gov/sites/prod/files/2013/04/f0/fr_notice_two_part_study.pdf

[28] "North America to Dodge Australian Curse?" WGI, November 26, 2014, See: http://www.energyintel.com/pages/eig_article.aspx?mail=PA_TEXT_10_927&DocId=868424

[29] Abdelal, Rawi, Leonardo Maugeri and Sogomon Tarontsi. "Europe, Russia and the Age of Gas Revolution." Harvard Business School Case N9-715-006, September 2014, p. 6.

[30] Cheniere Corporate Presentation, Feb. 10, 2014, slide 5, See: http://phx.corporate-ir.net/phoenix.zhtml?c=101667&p=irol-presentations

[31] "Asia Laps Up US LNG," WGI, July 2, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?mail=PA_TEXT_10_906&DocId=852531

[32] Author's interviews with several US LNG scheme developers.

[33] For an official assessment of Australian gas resources see: Geoscience Australia and BREE. Australian Gas Resource Assessment 2012. Canberra, 2012. See: http://www.appea.com.au/wp-content/uploads/2013/05/BREE-2012-GasResource_Assessment.pdf

[34] "Queensland LNG Schemes Save Face, But Is It RIP for Future Projects?" Energy Intelligence Finance (EIF) Briefing, January 8, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?DocId=833508

[35] "Costs Kill New CBM LNG." WGI, July 16, 2014. See: http://www.energyintel.com/pages/eig_article.aspx?DocId=853840

[36] According to companies involved in CBM projects, so far, per-well costs have fluctuated between AUD 1 million for BG's Curtis Queensland LNG, which relies on proven and probable reserves (or 2P reserves) of 9.9 trillion cubic feet (Tcf) , AUD 1.35 million for Santos-operated Gladstone, with 5.1 Tcf of 2P reserves, and AUD 3 million for Origin-ConocoPhillips's Australia Pacific LNG (which also includes other costs, such as connection to pipelines), with 12 Tcf of 2P reserves.

[37] "Australian LNG Tests the Limits to Growth." Petroleum Intelligence Weekly (PIW). Jan. 23, 2012. See: http://www.energyintel.com/Pages/Eig_Article.aspx?DocId=751891

[38] "Soaring Costs Worry Australian LNG Investors." PIW. Dec. 17, 2012. See: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=790829

[39] "Woodside Stake Next in Shell's Yard Sale." PIW. Feb. 3, 2014. See: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=836059

[40] "Woodside boss warns of costs nightmare." The West Australian, September 25, 2012, See: https://au.news.yahoo.com/thewest/a/14950050/woodside-boss-warns-of-costs-nightmare/

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[43] "Costs Soar at PNG LNG." WGI. Nov. 14, 2012. See: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=787189

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