Natural Gas: Entering the New Dark Age?
About KAPSARC

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Key Points

Many in the natural gas industry view the rise in the share of natural gas in the global energy mix as inevitable. However, this industry optimism is not reflected in the approach of policymakers. Liquefied natural gas (LNG) markets provide an insight into the state of the global gas business, because:

- The next wave of LNG supply projects is faced with uncertain demand growth—in Europe because of substitution by Russian imports and in Asia because of competition with coal.
- Imported natural gas is expensive relative to coal and, for the time being, developing countries value low cost energy for industrialization ahead of long-term environmental risks.
- North American LNG will likely secure a significant market share but does not guarantee lower prices for Asian consumers.
- Despite importer appetite to move away from long-term LNG contracts, often indexed to oil prices, it is far from certain that sellers will be capable of financing major infrastructure in the absence of such contracts.

Whatever the future holds, we can be certain that it will be different than the one envisaged as recently as five years ago and, probably, than the one we can envisage today.

Summary for Policymakers

Even the most aggressive decarbonization forecasts of the International Energy Agency (IEA) foresee a growing role for natural gas in 2040. Industry players forecast a role for gas as the fuel of choice, whether as a destination or a bridge fuel. And yet, in most parts of the world, this ‘inevitable’ rise of natural gas seems to be colliding with the reality: a high cost energy resource trapped between cheap coal and policy-supported renewables.

In just five years, global gas markets have been turned on their heads. The most striking change has taken place in the U.S. The rapid increase in U.S. shale gas production positions North America to become one of the three largest LNG exporters by 2020 with five terminals currently under construction, amounting to a capacity of 63 million metric tons (tonnes) per annum (mtpa). These are expected to start up between end-2015 and 2020. A few other U.S. projects are nearing final investment decisions (FID). This contrasts with previous views that it would be the importer of a similar quantity—which represents a swing of more than 100 mtpa.

More broadly, the wave of LNG projects currently under construction worldwide will add 137 mtpa, or nearly 50 percent, to current global capacity and is likely to create a boom-and-bust cycle. It seems inevitable that sponsors will be postponing the next generation of LNG projects as they wait for better times or re-engineer projects to counteract capital costs that have sky-rocketed in recent years.

On the demand side, natural gas has been struggling to position itself as the fuel of choice, despite its lower CO₂ emissions and flexibility. The lack of political support for expanding the role of natural gas in the future energy mix contrasts with the industry narrative of inevitable increases in demand and raises questions about its long-term positioning. Natural gas is squeezed in the European power sector by cheap coal-fired generation—partly resulting from the assault on coal in North America—and subsidized renewable resources. Gas consumption has collapsed by a fifth since 2010.

Outside of North America, which is embracing natural gas as a bridge to wean itself off coal-fired power, the pressures are different. Most notably in Asia, gas is often perceived as too expensive compared with coal. In the absence of any
enforceable carbon price, LNG and imported pipeline gas are considered luxuries that cannot be afforded for widespread use in power generation. Despite this, demand forecasts treat Asia as having an unquenchable thirst for natural gas over the coming three decades.

Price is at the core of any future gas market development. For a while, the Asian netback pricing of LNG seemed to provide a wide arbitrage between oil-linked prices from the Middle East and Australia and Henry Hub-linked prices from North America. One narrative saw the addition of such large U.S. LNG volumes as challenging the long established dominance of oil-linked and inflexible long-term LNG contracts with shorter-term spot cargoes of LNG. But current low oil prices have, for the time being, closed the gap—few arbitrages last beyond the capital cycle required to close them.

However, the global gas market is one that may face a pricing and contracting discontinuity. It is generally claimed that long-term contracts are required for funding massive, capital-intensive projects, but there are no examples of markets that have transitioned from such arrangements to liquid trading hubs ever returning to their original state without some major regulatory intervention. Asian buyers are seeking a way to match the power of North American and European trading hubs in terms of price discovery for the volumes they purchase. Seller resistance is holding this at bay for now but, if that door is opened by sufficient volumes of flexible LNG (or even liquidly tradable pipeline supplies), then there is likely no return.

Truly, the global gas market is poised at an inflection point and it is not inevitable that the long-term will lead to a new ‘Golden Age of Gas’. An unfortunate combination of policy and market structure could just as easily lead to the world’s stumbling into the new ‘Dark Ages of Gas’ unless it can escape being squeezed between policy and economic competitiveness.

**Background to the Workshop**

In March 2015, KAPSARC convened its first gas workshop in The Hague, Netherlands. This was the first in a series of workshops to explore global trends and shifts in gas markets. Discussions were framed around the need to better understand the future role of natural gas in the energy mix as well as capturing the market uncertainties regarding demand, supply and trade. The discussions focused on the following questions:

- Can gas have a future in a carbon-constrained world?
- Will Asia live up to the industry’s high expectations as a demand center?
- Who will be the new LNG suppliers post 2020? and,
- What fundamental changes could take place in terms of typical contractual structure in the LNG business?

**Does Gas Have a Role to Play in a Carbon-Constrained World?**

Many governmental agencies, energy companies and consultants have developed scenarios to present their views on long-term energy trends. Some of the analyses project far into the future, mostly to 2040, and some even up to 2100. While the energy industry needs clarity about market trends for its investment decisions, the last decade has also seen an increasing focus on the relationship between energy consumption and climate change.

Most scenarios usually paint a relatively bright future for natural gas, even if the outcomes differ in terms of overall energy demand as well as in terms of the specific role of each fuel in the energy mix at global and regional levels. The share of natural gas in the energy mix as well as its consumption expands up to 2040 in these forecasts. This is the case, even
when more stringent policies are implemented to reach a 2°C world—one in which the global temperature only increases by 2°C above pre-industrial levels by 2100 by limiting the concentration of greenhouse gas in the atmosphere to around 450 parts per million (ppm).

Gas demand growth is foreseen mostly in developing countries: Asia is usually seen as the largest center of incremental demand, followed by the Middle East, while Europe’s future is more uncertain. Shale gas production is expanding its role in North America and other regions. It will, along with gas from developing countries, feed this future demand growth.

However, recent history contradicts this vision. Gas demand growth has been relatively weak over the past two years—1% in 2013 and 1.1% in 2014, according to international gas organization Cedigaz—compared with the previous decade (2.8%). This occurred for a variety of reasons ranging from lower economic growth to mild weather but also including, more importantly, the market share of gas being squeezed by renewable energy and its not being price competitive against coal for power generation.

Consequently, there are concerns about the long-term role of gas in a carbon-constrained world. Despite being more efficient and presented as the ideal partner of intermittent renewable energy, gas still emits CO₂, even though this is two to three times less than coal for the same amount of energy produced. This is based on the implied emission factors—for gas 370g CO₂/kWh and for sub-bituminous coal 930g CO₂/kWh. Gas could contribute to a 2°C world, but it would not achieve it even if it were to become the main energy carrier on its own. The industry keeps highlighting the qualities of natural gas—available, affordable and abundant—but this message, while very popular within the gas industry itself, is falling on deaf ears among policymakers.
Indeed, no country has actually introduced policies recognizing the role of gas either as a bridge or a destination fuel. Only the U.S. is embracing gas, but not in the sense of promoting it: it is rather enjoying the benefits of gas which have created a cheap way of decarbonizing its power sector. In Europe, conditions have been created in which gas has been displaced by coal and renewable energy, even though this may have been unintended by politicians. Despite the creation of the European Emissions Trading Scheme (ETS), renewable energy has been subsidized outside of the scheme, depressing carbon prices. The power sector is the area which needs to be addressed as a priority, but there is no agreement on what a competitive system would look like. Current power market designs do not provide a role for natural gas, so that it is left to the market and to prices to determine it.

Concerns about future gas demand in a carbon-constrained world are particularly vivid in OECD Europe, where gas consumption has receded from 567 billion cubic meters (bcm) in 2010 to an estimated 450 bcm in 2014. Even though mild weather is largely responsible for this drop, natural gas has also plummeted in the power generation sector. Utilities have to mothball brand new combined-cycle gas turbine (CCGTs) power plants because of negative spark spreads; low spot prices since late 2014 have somehow improved the situation, but not sufficiently. ‘Green’ scenarios usually foresee a decline in European gas consumption, and even potential growth in the transport sector does little to reverse that trend. Two other issues affecting gas in Europe are the competitiveness of industrial firms facing higher energy costs than, for example, their North American competitors, and security of gas supply. Countries are increasingly reluctant to depend on a limited number of gas suppliers. The issue of dependency on Russia is still very much on top of the European political agenda.

In conclusion, it is possible to see two potential futures for energy in the very long term: one in which fossil fuels, including natural gas, would still be present, but with carbon capture and storage (CCS), and another one where renewable energy would dominate but still with CCS decarbonizing the small amount of fossil fuels left. In all cases, CCS would have a very important role to play, but its development is meeting population opposition on top of the low technical maturity of the technology. CCS may also have a role to play in allowing gas consumption to rise while meeting CO₂ policy targets. The question may be asked: why is the gas industry not putting more effort into that essential technology, unless it considers that the coal industry would have to solve that problem sooner?

Will Asia Fulfill its Promises as Future Demand Center?

Asia is widely seen as the growing demand center for natural gas, as well as for LNG. However, these bright prospects are facing the reality of an expensive resource that newly importing countries can simply not afford, as highlighted by the recent abrupt slowdown in Asian demand growth. It is possible that some Asian countries may have already passed their ‘Golden Age of Gas’. The role of gas in ASEAN’s energy mix is plateauing as countries are gas-short. They have mostly consumed their cheap domestic gas, leaving coal competing with imported gas at market prices.

Asia is a very complex region: there is no single homogenous Asia, but different countries from an economic, geopolitical and energy point of view. The historical LNG importers, Japan, Korea and Taiwan, belong to a group of relatively mature markets. In China and India gas currently represents a small part of the primary energy mix, but it is likely to reach significant levels due to the size of those countries’ future energy needs. Still, the
pace and timing of gas consumption growth are extremely difficult to forecast due to a wide range of potential outcomes including economic growth, environmental policies, affordability of gas, production capacity—notably of unconventional gas—domestic pricing policies and competition between pipeline gas and LNG imports. Finally, Southeast Asian countries face the common challenges of subsidized gas and power and constrained access to electricity for a significant proportion of their population. The region’s gas demand is highly concentrated, with Indonesia, Malaysia and Thailand representing 85% of ASEAN gas consumption. The geographical characteristics of Southeast Asia mean that imports will have to be in the form of LNG.

Despite the differences between markets, Asia is facing some overarching issues when it comes to its future energy needs:

- Economic growth and low energy prices will impact future energy needs, including for natural gas; this is particularly true for China.

- Decisions on nuclear energy, notably in Japan, Korea and Taiwan, but also in China, India and Thailand, will play a significant role.

- Gas-fired plants are often not competitive against coal-fired plants.

- Most Asian countries will become more gas import dependent.

- Some Asian countries are far more price responsive than others and have different ‘reasonable’ price levels that they are ready to accept.

In all Asian countries, the power sector is seen as a key driver for natural gas demand, but it could be subject to huge variations because of the factors mentioned above. However, it would be a mistake to discount other sectors such as industry as these have less potential to switch back to other fuels. Power demand in non-OECD Asia is expected to increase by over 10,000 TWh over 2012-40 according to the IEA’s World Energy Outlook 2014; this represents 60 percent of the world’s incremental power demand over that period and almost half of the world’s current total power demand. As Asian countries become more import dependent, they will be more exposed to global gas markets and prices. Until recently, LNG import prices in Asia were at record levels at above $15 per million British thermal units ($/MMBtu), sometimes twice as much as the wholesale prices in Southeast Asian importing countries and India.

Coal is the most competitive source of baseload power supply across Asia, requiring gas—and LNG imports in particular—to enhance their price competitiveness. Based on gas prices of $16/MMBtu, which was the average Asian LNG price over 2014, the analysis on levelized costs of electricity shows that gas-fired plants are not competitive against coal-fired plants, assuming a coal price of $70/ton ($2.94/MMBtu). However, prices at $7/MMBtu give a clear advantage to gas-fired plants because of gas-fired plants’ better efficiencies and lower capital costs. Still, the potential for further expansion of coal may be constrained by growing concerns regarding the consequences of coal use on health. This was highlighted by the more than 200 million views of the documentary Under The Dome—a Chinese documentary produced by journalist Chai Jing about local air pollution in China.
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While spot LNG prices in Asia have halved since 2014 to around $7/MMBtu due to oversupply, there is no indication as to how long this trend will last. Spot prices are likely to reflect the continuous LNG oversupply over the medium term while LNG contract prices will continue to reflect mostly oil price variations, with some impact from Henry Hub (HH) prices through U.S. LNG deliveries. Against this backdrop, most Asian governments recognize the need to reduce subsidies for fiscal and external balances reasons as well to control rising energy consumption. These two objectives tend to conflict if applied simultaneously, but together they create a very strong case for reducing imported energy. The current window of low energy prices represents a good opportunity to reduce subsidies.

Competition between LNG and pipeline gas is also important, notably in China, and possibly India. The Russian pipelines from Russia to China, if both are built, would have a large impact on LNG demand. There is still uncertainty as to how the planned Power of Siberia pipeline will be financed, even though it seems to be moving ahead. It is the subject of competition inside Russia between Gazprom and other producers, which are interested in using it for their own gas supplies. The fate and timing of the Altai pipeline still hangs upon a formal agreement between Russia and China. Timing and sequencing appear as more complicated due to sanctions on Russia that restrict access to financing.

Finally, many Asian buyers are very cautious about taking on long-term commitments, both in terms of volumes and pricing mechanism, due to future demand uncertainties. For example, in Japan there is still no clarity on the future energy mix, while LNG demand uncertainty on China and India has never...
been so great. Demand forecasts for China by 2020 range from 400 bcm down to 295 bcm. China now appears to be changing from a growth pattern driven by export manufacturing to one which is more driven by domestic consumption and services, making the picture overall quite challenging to read. This is an growing issue as buyers may be missing some windows of opportunity in terms of project development. At times of high oil and gas prices, U.S. LNG seemed to be cheaper but this is no longer the case. Hub-based pricing still seems to be attractive for the sake of diversification of supply sources and pricing mechanisms. Utilities are also more interested in flexible LNG supplies. One of the key purposes of the alliance between Japanese electric power producers Chubu and TEPCO is supply flexibility, even if that means having to deliver the LNG to Europe. From the suppliers’ side, many seem individually to be betting on the same amount of uncontracted LNG demand in China while around two-thirds of the LNG under construction is earmarked for Asia.

Who Will Provide the New Generation of LNG Supply?

LNG is widely seen as achieving a growing role in future gas supplies, notably in Asia. There are only a few countries and regions where the competition between pipeline gas and LNG will remain an acute question: Europe, China and potentially, India, Japan and Korea. A new wave of LNG supply has started flowing onto gas markets since May 2014, with ExxonMobil’s Papua New Guinea project, followed in January 2015 by BG’s Queensland Curtis in Australia. Around 137 mtpa is currently under construction and expected to start operating by 2020. This includes 53 mtpa from Australia and 63 mtpa from the United States.

Meanwhile, around 900 mtpa of liquefaction capacity is at the planning stage as of 2015, with over 500 mtpa located in North America. In a context of uncertain demand growth in Asia alongside high capital costs, the expected boom-and-bust cycle and low oil price environment are likely to defer many new LNG projects despite the need to replace dwindling supply from existing LNG suppliers. Four regions are still competing to bring substantial LNG volumes to markets: North America (the U.S. and Canada), East Africa (Mozambique and Tanzania), Australia and Russia. Apart from these regions, other projects could also be potentially viable, such as those in Papua New Guinea or even Iran, which currently appears as a wild card but could benefit from the lifting of sanctions against it. However, these volumes may materialize much later than anticipated, or not at all.

Given the pricing sensitivity of Asia, only cheap sources of LNG from projects relatively advanced in terms of contracting and technical evaluation have a chance of moving ahead. This means projects currently prefer to have at least 80% of their supply contracted. The ability of project sponsors to reduce their costs will be critical to move their planned LNG plants forward. Some U.S. projects are moving ahead in 2015, and Mozambique LNG seems also quite advanced, but other projects could be delayed, either because of difficulties in marketing the LNG or regulatory or financing hurdles, as well as competition from the domestic market for natural gas resources. More specifically:

- Australia is seen as a very expensive source of supply, and even brownfield projects have been for the moment put on the back burner.
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Russia is suffering from sanctions (even though these do not target LNG directly) and has difficulty accessing finance and technology.

U.S. projects are surrounded by an air of optimism, even if buyers may not really want all this LNG. However, U.S. LNG projects in the East and the Gulf may face bottlenecks while trying to reach Asian markets as only six ships a day can go through the expanded Panama Canal.

Canada may only have one or two projects seen as having a potential to move ahead, even though small FLNG projects could fill an additional niche.

Mozambique LNG is not a question of if but of when; such large gas resources are unlikely to remain stranded given the involvement of Asian companies. However, it is perceived that neither the companies nor the government have the capacity to drive these projects.

Tanzania is regarded as the least advanced due to political and administrative delays as well as lower reserves.

In all LNG exporting countries mentioned above, domestic or regional markets’ needs will matter and have to be included in any further analysis of LNG exports. Some U.S. companies, notably those in the petrochemical industry, have been lobbying against U.S. LNG exports. A large proportion of U.S. exports will take place in the form of pipeline gas, mostly toward Mexico to fuel gas-fired plants, while Marcellus shale gas production growth defies gravity and will impact Canada’s balance. The idea that U.S. gas could end up feeding Canadian LNG projects under the NAFTA umbrella is probably a bridge too far: the issue of where U.S. gas eventually finishes up has engaged the attention of U.S. regulatory authorities.

Both Mozambique and Tanzania have domestic needs, notably in terms of power generation. But any such development would require a gradual approach as domestic markets are constrained by low incomes and limited infrastructure. LNG exports are the anchor for these deep offshore gas developments as domestic markets alone could not support the high costs associated with them. According to studies done by the World Bank and consultancy firm ICF International, LNG ranks the highest for these countries as a commercialization option, followed by power generation, fertilizer, gas-to-liquids (GTL)
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and methanol, which all may provide opportunities depending on the local situation. Given the need to develop pipeline infrastructure, the markets have to be large enough and pay prices that allow a reasonable return on investment. However, in Mozambique, potential markets are small, spread and far from the discoveries located in the northern part of the country, while the country also has substantial hydro and coal resources. Exports from Mozambique to South Africa could in some cases provide a netback on par with LNG exports. In Tanzania, the government gives priority to the domestic market, driven in part by there being much less recoverable gas.

There is a remaining key uncertainty about the robustness of supply from North America. U.S. LNG projects are different than in many other parts of the world. Supply to the liquefaction plant will normally be sourced in the market without any effective take-or-pay provision. Therefore the marginal costs of supply, if tolling commitments are regarded as a sunk cost, are much lower than for plants elsewhere in the world. Few market participants expect any significant change in North American natural gas prices because the long-term shape of the supply cost curve for natural gas is assumed to be fairly flat. This is a reflection of the huge resources discovered and under development. However, should this assumption be flawed, that could strongly impact both LNG exports and the domestic market, resulting in U.S. LNG export capacity being underutilized.

Alternatively, if the buyers of U.S. LNG find themselves competing with lower-priced LNG from other countries, they would be faced with a choice. They could decide not to take the U.S. LNG and lose their tolling fee, or take it in the face of wholesale prices that would be lower than their costs. If buyers and sellers transact on the basis of ignoring the sunk costs, U.S. LNG exports might be more resilient in the face of a low global gas price environment than expected.

Is There a Future for Oil-Indexed, Inflexible Long-Term Contracts?

The vast majority of LNG and pipeline trade is currently based either on oil-indexation or on gas-to-gas competition. While gas-to-gas competition has made large inroads into pipeline trade, notably in North America but also in Europe, oil indexation continues to dominate LNG trade, with two-thirds based on that mechanism, according to the IGU Wholesale Pricing Survey.

Still, recent history provides food for thought as to whether oil indexation will persist globally. When oil indexation was introduced in the 1970s, the challenges faced by the gas industry were how to price gas against other fuels and how to finance its transport infrastructure. In the case of Groningen gas, a cost-plus approach would have made gas very cheap. Nevertheless, gas is one of the few commodities whose indexation is based on another commodity and not on its supply and demand. It is fair to say, though, that few commodities have such a high cost of transport. In Europe, oil indexation was dominant in most long-term contracts before 2009. Even though gas was no longer really competing against oil products in the end-user markets, the midstream gas industry was actually happy with such an indexation, as it could pass on the risk to the end-users. The transition to hub pricing in Europe occurred because of the cumulative impact of the regulatory framework which had been put in place since the late 1990s, the LNG supply surge in 2009-11 and midstream players losing money. As of 2015, most contracts have been renegotiated, including (partial) spot indexation.
By contrast, Asia remains largely dominated by oil-indexed long-term contracts which prevail in the LNG business. Japanese utilities had been allowed to pass through their costs onto gas and power tariffs, using the country’s average LNG procurement cost movements as a benchmark. Following the Fukushima nuclear power plant disaster, the spike in gas prices led to heavy losses and the mood changed. It created a strong desire for something new, such as hybrid prices. This is largely based on confusion between pricing mechanisms and price levels. Oil indexation is assumed to be ‘bad’ because it generates high gas prices, but this is only true when oil prices are high. Besides, there are multiple forms of oil indexation: under this rather generic term, the same oil price can generate many different gas prices depending on the characteristics of the individual formulas. But U.S. LNG no longer appears so price-competitive at current low oil prices. Still, the need to secure cheaper gas resources remains very much present in the minds of buyers and governments. Utilities, notably in Japan, have been looking at the transition to hub pricing in Europe and aim to originate large parts of their portfolios from the spot market. A change to a still-to-be-created Asian form of hub pricing seems unlikely to happen in the medium term: a hybrid mix of other indicators such as the U.S. HH, UK NBP or JKM (the Japan Korea Marker, reported by Platts) is the only credible alternative. However, persistent low oil prices may slow the transition to other pricing mechanisms as the rationale to achieve lower prices based on hub indexation disappears.

**Figure 4** – Gas Price Environment, 2007-15
Sources: EIA, Japanese customs, German Ministry of Economics.

The attempt to move away from oil indexation has been met by resistance from the sellers. Main reasons are that the industry is adverse to changes, oil indexation usually generates higher prices than spot prices, and banks are more comfortable when
they have tools to mitigate the volatility of oil prices. There is also the issue of risk management as gas markets are not global. Sellers may want to grant some concessions, but mostly to maintain buyers in business. Finally, resource-owning governments like to see the value of gas as close as possible to that of oil (when oil prices are high), which has been illustrated in the past by the positions of Bolivia, Algeria, Qatar and even the Netherlands.

Beyond the medium-term solution of using HH, NBP and JKM as an alternative price indexation, Asia is still looking at creating an indigenous spot price. JKM is not a trading hub, but a price assessment of ex-ship spot cargoes delivered in Japan and Korea. Even if it were to represent all LNG spot cargoes, that would be equivalent to only 1.5 cargo a day. In Europe and North America, the creation of trading hubs was largely based on domestic production and pipeline gas, hence a relatively continuous flow of gas. Countries with the most liquid hubs (the U.S., the UK and the Netherlands) were actually self-sufficient or very close to it when their hubs were created. Interestingly, the UK becoming an importing region has not affected the liquidity at the NBP. In Asia, all the supporters of the creation of a hub are dependent on natural gas imports.

There will be many challenges on the road to the creation of a trading hub in Asia, starting with the structure of Asian markets themselves. Unlike Europe, which was a relatively mature market when liberalization started, Asia is still growing rapidly and has still to build its entire infrastructure, including facilities to provide flexibility. Besides Singapore, very few markets can offer wholesale pricing deregulation, a government with a hands-off attitude and genuine third-party access to infrastructure, notably LNG terminals and pipelines. Most of the Asian gas sector is heavily regulated. There have been some attempts to deregulate the gas industry in some countries, including talks about introducing third-party access in Japan and China, but very few steps have been made. Japan envisages liberalizing its gas markets only by 2017, requiring it to put in place transparent and efficient third-party access. Although Singapore is relatively advanced in terms of liberalization, it is a small market (around 10 bcm), the equivalent of 2 LNG cargoes a month, which is clearly insufficient in providing liquidity.

The second challenge comes from the nature of LNG itself, as Asia will depend mostly on a mix of LNG and domestic production together with pipeline gas in China. LNG poses a two-fold problem: deliveries are spaced in time and LNG must be stored. The spot LNG trade will continue to remain an opaque bilateral market and is unlikely to become a fully traded market. Any spot market would have to be based on the regasified part of the gas value chain, which would solve issues of different LNG qualities and lack of liquidity.

Conclusion

Only the gas industry seems to be convinced of the long-term benefit and potential of natural gas in the energy mix. Other stakeholders appear unable to see it as a long-term solution to a carbon-constrained world. As a result of the lack of policies supporting natural gas, it is currently squeezed either by coal or by renewable energy. Decarbonizing the energy system in the long term requires using gas with CCS, which is not yet a mature technology.
The lack of competitiveness of gas compared with coal creates question marks over the scale of Asia’s appetite for natural gas at a time when significant LNG supplies are on their way to global markets and likely to create a boom-and-bust cycle. Asia could be the large demand center that everybody expects, but only if prices make gas competitive against coal in the power sector. Increasing environmental concerns are likely to play in favor of natural gas, notably in China, but demand uncertainty appears considerable for the whole region.

There seems to be an ongoing LNG overbuild, with most investors betting on the very same large import needs from Asia. This potential oversupply, combined with the current low oil price environment, seems likely to deter FIDs over the coming years. During the current period of lower oil prices, capital costs are being slashed as companies behind large infrastructure projects have to manage their cash flows to balance revenues with expenses. More delays and company mergers can therefore be expected.

Finally, market conditions will determine whether buyers will be happy to keep oil indexation in a context of low oil prices or whether a new pricing structure based on alternative indices will emerge in Asia, creating a basis for potential future establishment of a trading hub. The price advantage of U.S. LNG is currently non-existent. Changing pricing mechanism would therefore serve only as a strategy of diversifying pricing portfolios. The transition to a regional Asian spot price seems as distant as ever, unless Asian markets move away from heavy regulation and state interventions. Though spot LNG alone would be unlikely to support it, an Asian trading hub could emerge based on regasified natural gas. Finally, there still seems to be little appetite for a transition away from long-term contracts.
About the workshop

In March 2015, KAPSARC convened the first workshop in its global gas markets energy workshop series. The workshop was hosted by the Clingendael International Energy Programme at the Huys Clingendael in The Hague, The Netherlands. The workshop, attended by policymakers, researchers and industry practitioners, was conducted on the basis that the discussions could be reported on a non-attribution basis. Participants included:

Shahad AlArenan – Research Analyst, KAPSARC
Samer AlAshgar – President, KAPSARC
Ziyad AlFawzan – Research Analyst, KAPSARC
Nader Al-Kathiri – Senior Research Analyst, KAPSARC
Majid Al-Moneef – Secretary General, Kingdom of Saudi Arabia Supreme Economic Council
Yazeed Al-Rashed – Senior Research Analyst, KAPSARC
Hamad Al-Sayari – Former Governor, Saudi Arabian Monetary Agency (SAMA)
Simon Blakey – Managing Director, SAB Global Energy
Jason Bordoff – Director, Center on Global Energy Policy Columbia University
Amulya Charan – Independent Advisor
Anne-Sophie Corbeau – Research Fellow, KAPSARC
Dick de Jong – Senior Fellow, Clingendael International Energy Programme (CIEP)
Tilak Doshi – Program Director, KAPSARC
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Vlaidmir Feygin – President, Institute for Energy and Finance (IEF)
Luca Franza – Researcher, Clingendael International Energy Programme (CIEP)
Fabio Gabrieli – Director, Dry Bulk Analysis and Strategy, Mercuria Energy Trading S.A.
Quentin Grafton – Chairholder, UNESCO Chair in Water Economics and Transboundary Water Governance, Australian National University (ANU)
Manfred Hafner – Associate Researcher, Fondazione Eni Enrico Mattei (FEEM)
David Hobbs – Head of Research, KAPSARC
Philippe Hochart – Directeur LNG Stratégie et Communication, GDF Suez
Nicholas Howarth – Research Fellow, KAPSARC
Alexander Huurdeman – Senior Oil and Gas Expert, The World Bank
Markus Klingbeil – Senior Energy Analyst, International Energy Agency (IEA)
Ken Koyama – Managing Director, Chief Economist, Charge of Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ)
Angelina LaRose – Natural Gas Markets Analysis Team Leader, EIA (Energy Information Administration)
David Ledesma – Senior Research Fellow, OIES
Giacomo Luciani – Professor, Institut de Hautes Etudes Internationales et du developpement
Marwan Masri – President Emeritus, Canadian Energy Research Institute (CERI)
Jane Nakano – Senior Fellow, Energy and National Security Program, Center for Strategic & International Studies (CSIS)
Pierre Noël – Sultan Hassanal Bolkiah Senior Fellow for Economic and Energy Security, The International Institute for Strategic Studies (Asia) Ltd
Ke-Xi Pan – Professor, Fudan University
Alfonso Puga – Head of LNG, PetroChina International UK
Howard Rogers – Director, Natural Gas Research Programme/Senior Research Fellow, Oxford Institute for Energy Studies (OIES)
Jon Rozhon – Senior Researcher, Canadian Energy Research Institute (CERI)
Susan Sakmar – Visiting Assistant Law Professor, University of Houston Law Center
Adnan Shihab-Eldin – Director General, Kuwait Foundation for the Advancement of Sciences (KFAS)
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