



CHINA: THE EMERGENCE OF A MAJOR NEW LNG DEMAND MARKET IN ASIA ?

Much attention has been devoted by LNG exporters and project developers to the prospects for growth in the Chinese LNG import market, but many also recognise that this is a nascent market and has its fair share of emerging market risks. This *White Paper* considers how and when China might come to be a major new LNG demand market and what obstacles might need to be addressed in order for that to happen.

Before examining the emergence of the Chinese LNG market however it might be helpful first to consider the hallmarks of historical LNG supplies into north Asia, notably Japan and South Korea, so that the prospects for the development of the Chinese LNG market might be better understood.

“TRADITIONAL” LNG IMPORTS INTO NORTH ASIA

Japan began importing LNG in 1969 and South Korea in 1986. Since then both countries have become sig-

nificant LNG importers (they are now respectively the world's first- and second-largest importers of LNG, with annual imports presently of around 55 MTPA and 20 MTPA).

Several features have historically characterised LNG imports into Japan and South Korea, which have become regarded as “traditional” sale and purchase (SPA) arrangements:

The Buyer. The buyer has always been a creditworthy gas or power utility, such as Tokyo Electric Power Co (TEPCo), Tokyo Gas or the Korea Gas Company (Kogas). Each of these buyers has historically held an authorized monopoly franchise over a geographically defined downstream business area and therefore has enjoyed the prospect of a reliable, long-term revenue stream from committed end-users. The hallmark of these contracts has been the creditworthiness of the buyers. In neither Japan or Korea have LNG suppliers been faced with the prospect of combining merchant sales into evolving markets.

Duration. The primary desire of Japanese and Korean LNG buyers has been to lock in a long-term, stable supply of LNG. As price, market and project risks could largely be passed through to end-users, the buyers would be primarily concerned to ensure long-term security of supply, and consequently the typical duration of an SPA would be for between 20 and 30 years.

Price. The price of LNG has been indexed heavily against crude oil price movements, principally by reference to a formula comprising a fixed component plus a variable component equal to an agreed percentage of Japanese Customs Cleared (JCC) aggregate prices for Japanese CIF crude oil imports. This linkage to imported oil prices was originally made at a time when Japanese power generation was heavily (about 50%) dependent on fuel oil as a primary feedstock and so, as about 70% of Japan's LNG imports are intended for power generation, the decision to index LNG prices against imported oil prices would have made sense since this was the majority competing fuel. This pricing mechanism was largely adopted also by South Korean buyers and for Japanese and South Korean buyers has remained relatively static over the years as these SPAs typically did not provide for price review or reopening. This heavy indexation to crude oil price movements has however resulted in relatively high LNG prices.

Take-or-pay. Japanese and South Korean buyers have traditionally proved themselves willing to meet the LNG supplier's requirement to enter into an annual take-or-pay commitment equivalent to 100% of the annual contract quantity, with off-take flexibility being achieved only through the usual (limited) take-or-pay adjustments and only limited (and often no) scope for further downward flexibility.

Flexibility. As mentioned above, the principal concern of the buyer under these traditional SPAs was always to secure a reliable supply of LNG, and it would be of less concern that the SPA should contain provisions for upward and downward volume or cargo scheduling flexibility. To further diminish the need for within-contract flexibility mechanisms, a buyer would typically invest heavily in gas storage facilities.

Shipping. LNG was typically sold ex-ship, with the buyer paying a bundled price for LNG covering commodity and transportation costs. It was not until SPAs entered into effective

1983 for the supply of LNG from Indonesia's Bontang project that the first FOB sales into Japan occurred, although this arrangement was something of an exception rather than the rule and subsequent contracts with the North West Shelf and Qatargas projects were entered into again upon an ex-ship basis.

Japan's dominant influence in Asia and world LNG markets from their infancy cannot be underestimated. Japan currently accounts for almost 50% of all LNG trades worldwide, and some 70% of all LNG movements in Asia are presently headed for the Japanese market. Japanese SPAs effectively founded today's LNG production capacity in the US (first producing in 1969), Brunei (1972), Indonesia (1977), Abu Dhabi (1977), Malaysia (1983), Australia (1989), Qatar (1996) and Oman (2000). When other north Asian countries began to plan for the import of LNG, the Japanese model was adopted as their benchmark because of its obvious stability and so something of the old order was perpetuated in the first SPAs for the sale of LNG into South Korea and Taiwan.

The features described above have combined to make Japanese and South Korean LNG buyers a very attractive proposition for LNG suppliers. Competition has often been keen to secure these lucrative supply opportunities and in turn those opportunities have often been the backbone of greenfield and expansion liquefaction projects. Against the revenue stream which would be generated under such SPAs the LNG suppliers were readily able to secure third party debt financing on a limited recourse basis for the development of their LNG production and transportation facilities. Consequently this form of purchase and finance arrangement also became the benchmark for the project financing of LNG liquefaction and transportation projects worldwide.

THE EMERGENCE OF CHINA, AND LNG IN CHINA

China has quickly emerged as the land of superlatives. China is the world's most populous country (currently with a population of almost 1.4 billion) and is now the second-largest energy consumer (after the US). With no prospect of a hard landing presently in sight for the Chinese economy (which demonstrated a GDP of growth of 9.5% in 2004, with a similar growth figure expected for 2005), the country has an increasing and seemingly insatiable demand for energy.

China's economic growth was outstripped by the rise in Chinese energy demand, which increased by more than 15% for 2004. Over the past three years, Chinese energy demand has risen by 65%, accounting for more than half the increase in global demand over the period.

So where does China get its primary sources of energy from? China is well-known as a net importer of oil (importing around 2.9 million barrels per day in 2004); less well-known is that with an indigenous daily production of approximately 3.5 million barrels, China is a significant oil producer in its own right and currently produces more oil than Indonesia, Malaysia, Qatar and Brunei combined.

China has significant coal reserves (presently estimated to be around 126 billion tonnes) but much of this coal is of low thermal value and has a high sulphur content. That said, over the longer term China's consumption of coal is projected to rise significantly. While coal's share of overall Chinese energy consumption is projected to fall, coal consumption will still be increasing in absolute terms. Several projects exist for the development of coal-fired power plants co-located with large mines, and other technological improvements are also being undertaken, including the first small-scale projects for coal gasification. China has expressed a strong interest in coal gasification and liquefaction technology and, despite the high costs, Chinese officials hope that coal may eventually provide an economically viable domestic source of gas and liquid fuels and so could displace the need to rely on foreign energy imports.

The Chinese government has also declared its commitment towards promoting much greater use of gas, with the intention to see China's reliance on gas grow from the present 3% of the country's fuel feedstock mix to 10% by 2020.

China has some 60 trillion cubic feet of indigenous natural gas reserves but much of this gas is remote from the energy demand centres of China's eastern seaboard, mostly located in the far west and north-central provinces. CNPC completed construction of the 3000 km "West-East" gas pipeline earlier this year, which is intended to carry gas from some of these remote reserves centres to China's eastern cities and with an anticipated peak capacity of 12 billion cubic metres per year. There are even plans for a second such pipeline, with a design capacity of 26 billion cubic metres per year.

Further afield, plans to import gas into China's far west from Kazakhstan (and thence by the pipelines referred to into China's eastern areas) are gathering pace.

To meet the shortfall between growing gas demand and indigenous supply, LNG is often suggested as a means of plugging the gap.

China's first LNG import project, the Guangdong LNG terminal and trunkline project, consists of a 3.7 MTPA import and regasification terminal and approximately 213 kilometres of trunklines and associated facilities for the reticulation of regasified LNG. There is an option for the second phase expansion (2 - 3 MTPA) of the project. At the heart of the project is an LNG sale and purchase agreement for more than 3 MTPA of LNG over 25 years on an FOB basis from the Australian North West Shelf venture.

Due on stream in 2006, the project will deliver gas by pipeline to Hong Kong and throughout the Pearl River Delta for use in city gas networks and power plants. LNG deliveries to Guangdong Province and neighbouring Hong Kong are intended to offer a cleaner-burning and more cost-effective supplement to existing fuels. The first non-recourse deal in China financed purely by Chinese banks while using international financing techniques and standards, the Guangdong LNG import project sets a keen precedent for other Chinese LNG import projects.

The project will be developed, owned and operated by Guangdong Dapeng LNG Company Ltd, a special purpose joint venture company owned by a consortium comprising CNOOC (a PRC state-owned enterprise), various towngas company and power generator gas buyers in Guangdong and Hong Kong, and BP. Strong support for the project has been expressed by Chinese central and local government entities.

One of the most important elements in the success of the project is the strong market fundamental of support from downstream projects to underpin the operation of the terminal. The project has a total of 12 principal gas offtakers, of which six are local gas distribution companies, five are newly built gas fired combined-cycle gas turbine generators and one is an oil to gas fired power plant conversion. Demand for LNG is expected to increase gradually as the downstream

transmission pipeline network is further developed with the growing economy.

Beyond Guangdong, CNOOC's Fujian LNG import project (and China's second LNG import project) is set to import 2.6 MTPA from Indonesia, with deliveries due to commence in 2007/2008.

In China there has been much effort devoted to planning new LNG import terminal projects, but whilst many are planned, much fewer will be built. This is a quick summary of the current state of play, in decreasing order of certainty and excluding the more remote and improbable possibilities:

Terminal	Capacity (MTPA) (baseload, without expansion)	Expected operational date
Guangdong (Dapeng)	3.7	2006
Fujian	2.6	2007/2008
Zhejiang (Ningbo)	3.0	2008
Shanghai (Yangshan)	3.0	2008
Shandong (Qingdao)	3.0	2008
Hebei (Tangshan)	6.0	2008
Guangdong (Zhuhai)	4.0	2009
Jiangsu (Rudong)	3.5	2009
Tianjin	2.0	2010
Liaoning (Dalian)	4.0	2010

According to one recent estimate, there is currently in prospect in China no less than 18 separate import terminal proposals which together could result in some 45 MTPA of import capacity. Given the enormous rate of growth of the Chinese economy, and the country's corresponding growth in its demand for energy, it should be of little surprise if future prospective Chinese LNG import projects begin to move towards fruition.

In June 2005 news began to circulate however that the National Development and Reform Commission had sought to bring some order from the chaos with a suggestion that henceforward there would be a limitation of one LNG import terminal for each province (with the exception of Guangdong Province, where the Dapeng project would be afforded exceptional status as a pilot project and a second terminal would be permitted). This edict, which has yet to be formally

published, will mean that many planned import projects will inevitably be shelved in the drive towards rationalising the number of proposals and so this should prevent what the Chinese government fears could be the needless duplication of LNG import facilities. Initial indications are that CNOOC would be allowed to develop projects in the provinces of Guangdong, Shanghai, Fujian, Hainan and Zhejiang; Sinopec would be allowed to develop projects in the provinces of Tianjin, Guangxi and Shandong; and CNPC would be allowed to develop projects in the provinces of Liaoning, Jiangsu and Hebei.

CHINA'S LNG IMPORTS—THE LANDSCAPE FOR FOREIGN PLAYERS

When commenting on the current and prospective status of the Chinese LNG sector, it should be remembered that as of today not one cargo of LNG has yet landed into China. There are two LNG import projects in construction and several more on the drawing board, each in varying stages of evolution. This is a thin basis for any kind of meaningful predictor. Though much has been said by commentators about the radical evolution of the Chinese LNG import market in comparison with "traditional" Japanese and South Korean arrangements, the truth is that Chinese sale and purchase arrangements have demonstrated, and are likely to continue to demonstrate, only a modest move away from the traditional model. Long-term, take-or-pay based SPAs have (thus far at least) been at the heart of Chinese LNG import schemes. It is only really on price and flexibility that a difference appears, and this would be the same consideration for any new buyer in possession of a demand-rich market and keen supply competition to access that market. There are, however, several features of the emerging Chinese LNG market which are worthy of note.

The first, and most important, feature is the nascence of the business of importing LNG into China. There is not a deep or settled market and much remains to be seen as to how the market evolves. LNG will have to be price-competitive with indigenous and established energy forms. LNG is new to China and is intended, initially at least, to replace the use of LPG, manufactured gas and the lighter competing oil products such as diesel and kerosene and so to provide new opportunities in downstream markets. Given the low costs of indigenous coal

production, the prospects for imported LNG to displace coal in the power generation feedstock mix are further down the road, although some forecasts see a major increase in gas consumption in the Chinese power generation sector at the expense of coal consumption, which could fall from the current figure of 66.7% of the feedstock mix to 52.6% by 2020.

In the early stages of the growth of LNG in China, therefore, some form of economic engineering (through subsidies for gas and/or the tariffing of other forms of energy) may be essential in order for the market to develop.

Much has also been said about how low prices are for the import of LNG into China. This comes in part at least from observation of the Guangdong and Fujian deals, but some commentators are suggesting that prices are firming up and that we are now in the “post-Guangdong” era of LNG pricing. Whilst there is various commentary about prospectively rising prices for Chinese LNG imports there is it would seem just as much commentary to the effect that resultant landed gas prices might be “too high” to be sustainable in downstream markets.

There might also be some evolution in Chinese LNG import pricing with a move away from the traditional indexation to imported oil prices in favour of indexation against coal price movements, since coal rather than oil is the primary power generation feedstock in China. However, LNG importers may be nervous of indexing to coal which they could see as a low grade, environmentally disadvantaged and prospectively low escalation fuel.

One aspect of Chinese LNG project structuring which appears to be in evolution is the need for the participation of the LNG supplier in the regasification terminal side of the project. This has been suggested to be a necessary feature, but in the Guangdong project the eventual LNG supplier did not make such an investment and in the Fujian project there is no foreign participation in the regasification terminal. It remains to be seen what happens with future projects.

One aspect of Chinese LNG project structuring which does not appear to be changing however is the desire of whichever Chinese state oil company is involved in the project to secure upstream equity. This has clearly been a feature of

the Guangdong and Fujian projects and is likely to remain a feature of any future Chinese LNG import project. This is consistent with the strategic desire of the Chinese government to secure access to oil and gas reserves worldwide.

Another issue to consider when investing into gas projects in China is the lack of a unified regulatory system. Currently, gas prices are governed by a patchwork of regulations. The Chinese government is in the process of drafting a new legal framework for the gas sector but the process has been slow and there are still considerable uncertainties regarding price regulation and taxation issues dealing with gas sales.

Perhaps the dark horse to watch in the emergence of the Chinese LNG sector is what happens with China's nuclear industry. Many of the major developments presently taking place in the Chinese electricity sector recently involve nuclear power. China's total installed capacity for nuclear power generation increased from 2GW at the beginning of 2002 to 15GW as of mid-2005. A new 6GW nuclear complex is planned for construction at Yangjiang in Guangdong Province, to begin commercial operation in 2010. Chinese government policy emphasizes nuclear power generation as a source of clean electricity generation and a means of reducing dependence on fossil fuels. China plans a total of 27 GW of additional nuclear generating capacity to be completed by 2020. Although even with this large capacity expansion nuclear power will make up less than 5% of China's total installed capacity at that point, this could be a keen cost competitor to the growth of LNG.

In fact, a combination of growth in China's coal and nuclear sectors could eventually lead China to the situation where these indigenous forms of energy might be more attractive (both economically and geographically) than imported energy sources, like LNG. In the longer term this could be an issue for the Chinese LNG import sector to be wary of. Instructive in this perhaps is news from Japan, with the declaration from TEPCo earlier this year that it had increased its nuclear power plant utilization rate to 61.7% for 2004 (versus a rate of 26.3% for 2003), at the expense of LNG imports which in 2004 were down 12.9% from 2003. This shift in the feedstock mix was attributed in part to the drive of TEPCo to reduce its exposure to price volatility in fossil fuel imports linked to rising crude oil prices.

THE RUSSIA/CHINA AXIS

In looking at the prognosis for LNG in China it is also essential to examine the relationship with Russia. With the world's largest gas reserves, presently estimated to be around 1700 trillion cubic feet, and a lengthy contiguous border with China's northern and eastern borders, the prospects of exporting Russian gas into energy-hungry China is an obvious connection to make. Relationships between Moscow and Beijing have been strengthening quietly, particularly in the last 18 months, with reciprocal presidential visits and various military, trade and energy accords having been reached.

Yet there are political concerns which appear able to overturn the commercial logic. The most controversial issue currently in Sino-Russian relations is the question of Russian pipeline infrastructure taking crude oil into China. The Russian government has for some time been trying to decide between two competing crude oil pipeline export routes into the Far East: the first would come out on the Russian Pacific coast at the port of Nakhodka and would be capable of exporting crude oil throughout the Pacific Rim (including potentially back into China); the second would see Russian crude oil landed directly into China's oil producing and refining region of Daqing. The Japanese government, equally hungry to secure future supplies of oil, has been lobbying hard for the Nakhodka option. Until a final decision is made on the crude oil pipeline route (and it would appear that some "indicative" final decisions have variously already been made), some commentators have suggested that there will be an inevitable slowness in the plans to import Russian gas into China.

Russian gas could make its way into China as LNG (or some suggest even by pipeline) from the Sakhalin projects offshore China's north eastern seaboard. Sakhalin II, the Shell-led front runner project for the export of Sakhalin hydrocarbons, presently has around 30% of its planned output still unsold and this could be aimed into China. Sakhalin I, the ExxonMobil-led project, is still seeking markets for its gas.

There are also ambitious plans for the import of Russian gas into northwestern China by pipeline. Rusia Petroleum, a TNK BP-led consortium, is presently developing a pipeline for the export of Siberian gas into China. This pipeline could have a total daily transportation capacity of around 2.9 billion cubic feet.

For Russia to cement its position as a global energy supply economy, the securing of access to demand markets in China, the world's fastest growing energy demand market, would appear to be essential. Much remains to be done (operationally, politically and commercially) in order for this to happen, but the size of the opportunity which presents itself will surely prove to be a powerful incentive to get things moving. The recent decision by state-owned Rosneft to allow Sinopec and CNPC to participate in oil and gas development ventures offshore Sakhalin through various co-operation agreements is real evidence of deepening Sino-Russian relations.

EVOLUTION IN ASIA'S LNG MARKETS (AND WHAT THIS COULD MEAN FOR CHINA)

Asia's LNG sector has evolved in recent years and the contractual terms of the first generation traditional SPAs, which were eminently appropriate during the 1960s to 1990s, might now begin to look somewhat dated. With an increase in traded volumes and the number of market participants over the last three decades, the Asian LNG market has developed increasing liquidity and today's LNG buyer is looking to reallocate project risks and rejuvenate the economic matrix in new generation SPAs.

The anticipated additional demand for LNG from new market participants could coincide approximately with a number of original and extension north Asian SPAs coming up for renewal. For new market entrants and renewing buyers there is perhaps a real opportunity to secure better, more flexible terms for the supply of LNG in what is being widely characterized (in perception, if not in reality) as a buyers' market.

Some commentators have suggested that evolution of SPAs in Asia is attributable to the emergence of Chinese demand. It might be more accurate to suggest however that in Asia today there is a process of evolution which has been underway for a while, which predates the emergence of China and which affects all buyers equally (including the Chinese).

The following aspects of the SPA relationship are areas where change could occur:

Duration. Compared to the traditional SPA model, shorter-term (e.g. 3 to 10 year) LNG supply contracts may be negotiable, so that the buyer is locked into a particular contractual relationship only for that lesser duration and thereafter is free to seek alternative arrangements. In a market where there is expected to be an excess of supply and a matrix of contractual and economic terms which is trending towards providing greater benefits to buyers, shorter-term commitments will enable buyers to have security of supply over the medium term without substantially locking themselves out from currently unobtainable benefits that might be secured from LNG suppliers over the coming few years.

Take-or-pay. The reduction of effective take-or-pay commitment levels may be possible to achieve. High take-or-pay levels are required by LNG suppliers to provide a guaranteed revenue stream to facilitate the financing of their liquefaction and associated facilities. Buyers might be resistant to agreeing to high take-or-pay levels when buying from brown-field LNG facilities where the initial capital costs of those facilities have already been recovered by the LNG supplier. Furthermore, as LNG typically forms only a certain percentage of a buyer's total supply of feedstocks, then the ability of that buyer to sustain large and somewhat inflexible take-or-pay commitment levels is constrained and the buyer may require greater flexibility in order to accommodate variability in the demand of its downstream end-users.

Volume flexibility. The SPA might contain volume flexibility mechanisms whereby a portion of the annual contract quantity might be variable over several short-term periods within a longer-term SPA, or volumes might be variable within each contract year or on a year-to-year basis so that the buyer can modulate its annual commitments in order to meet downstream market requirements. For the LNG supplier the provision of volume flexibility will help to retain market share as otherwise a buyer might contract for lower quantities and secure its flexibility through spot or short-term contracts from alternative LNG suppliers as and when needed.

Destination clauses. There may be a relaxation of the traditional restrictions to allow the buyer the ability to freely resell its contracted cargoes into other markets where there may be spot-selling opportunities, or to enable several buyers to collaborate to take advantage of different seasonal demand patterns, available shipping capacity or coordinated annual

programmes and lifting schedules. An LNG supplier might be encouraged to relinquish LNG resale controls, designed to prevent its customers from taking advantage of arbitrage and other market opportunities at its expense if the economic benefits of the resale opportunities are to some extent shared with that supplier. Some commentary has also been made about the possibility of "grey market" exports of lower-priced Chinese LNG by Chinese buyers into higher-priced north Asian import markets, such that the positive price differential can be exploited by those buyers. This is unlikely to be an issue however at least for as long as China's primary need is for energy in order to sustain its economic growth.

Shipping control. Where the buyer is able to take delivery of LNG on an FOB basis then flexibility associated with ship scheduling will pass to the buyer, and this could in particular better enable the buyer to manage the potential exchange or resale of LNG cargoes and to reroute cargoes to alternative terminals.

Pricing. There may be movement away from fixed escalation price mechanisms to short-run price packages, spot market price indexation and pricing referenced against fuels other than, or in combination with, crude oil or against power prices in order to better reflect the buyer's downstream market. Most favoured nation status pricing has historically been rare within Asian SPAs but, when faced with better economic bargains held by domestic and international competitors, such a sentiment might find growing favour with certain Asian buyers, notwithstanding that it is not actually memorialised within the SPA.

Aggregated parties. Japanese buyers have historically banded together when buying LNG, a practice which provided them with additional negotiating strength. The future may see a replication of this practice on the LNG supplier side, with suppliers from different projects cooperating to provide greater flexibility and cost efficiency as the market becomes leaner. Deliveries under SPAs might cease being supply source specific and could be made from a variety of LNG production projects. It is instructive to note that in November 2002 representatives of the LNG producers in Malaysia, Indonesia and Brunei signed an agreement to cooperate through the use of production surpluses and transportation capacity in order to provide their customers with greater security of supply and to help stabilize LNG prices.

Buyers. A key issue for LNG suppliers is the changing identity of LNG buyers. Recent changes in the way LNG is bought and sold have arisen at least partially in consequence of energy sector deregulation throughout Asia, allowing new participants to enter the market. Probably the most significant change in the evolution of LNG markets is the changing nature of downstream gas and power markets, which have proved to be the weakest link in the traditional LNG value chain. Power generation continues to be the major anchor for LNG demand but the nature of the market has changed; the liberalisation of downstream energy markets has created a whole new class of buyers, more likely to be IPPs than state entities, with no government backing and holding either unreliable PPAs or the merchant risk of selling into a power pool. Increased competition has also meant that buyers have a new priority to secure much more flexible purchase terms as their downstream markets evolve rather than focusing predominantly on security of supply. Even in Japan, energy sector regulatory reform is threatening to do away with the old end-user franchises whilst LNG buyers have for so long enjoyed. Gas and power competition has for the first time brought to LNG suppliers into Japan the prospect of merchant sales into an evolving market.

Chinese LNG buyers would do well to note the changing landscape detailed above since they ultimately could benefit from it.

CONCLUSION

The demand for gas in China is set on a path of continued growth, and LNG is potentially at the heart of the evolution of China's gas markets. There are many challenges ahead. Perhaps the most immediate challenges face LNG suppliers however: to develop and finance sustainable projects in the face of increasing fragmentation of the old world order; to control the seemingly insatiable appetite of buyers for leveraging a position which they presently enjoy because of the perception, however temporary or unreal that it might be, that demand currently has the upper hand over supply; and to assess the real depth of the Chinese LNG import market.

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