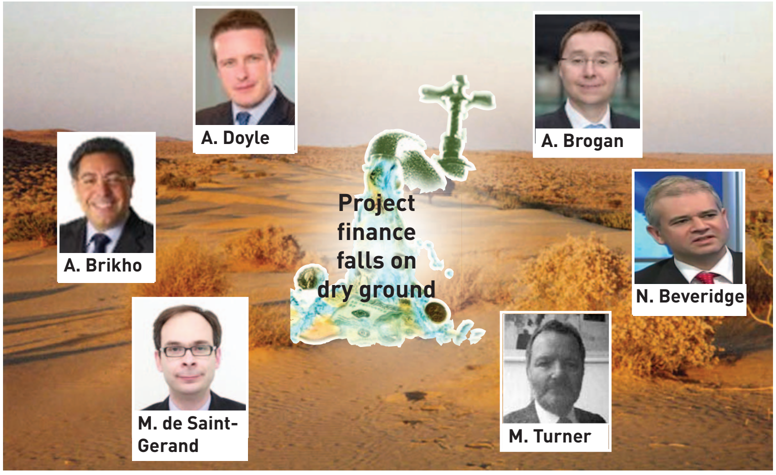
LNG North America

A MONTHLY LNG JOURNAL PUBLICATION March 2015

Projects get shelved as financing is drying up

As Big Oil rushes to business with lower breakeven costs, financing for integrated shale gas development and liquefaction is getting hard to come by. Tapping private equity or sovereign wealth funds is one way out, but Morgan Stanley's head of EMEA Oil & Gas Adrian Doyle warned "there is now a much bigger question mark on LNG projects which are pre-FID."



Several North American LNG projects have been postponed, if not outright cancelled. BG Group has delayed the 15 mpta Lake Charles LNG project in Louisiana, while Petronas and its partners in North-West LNG deferred financial investment decision on the $36 billion project.

Aspiring developers of oil and gas projects can no longer turn to bond markets, which used to rely on cash flow projections of oil at $100/bbl, but **EY's** global oil and gas leader Andy Brogan sees "a lot of scope for getting financing from sovereign wealth and infrastructure funds." Fierce criticism was voiced over "appalling terms of capital that the industry has delivered due to a lacklustre history of projects going over budget and over time." Some "choppy six months" are now lying ahead as capital providers are resetting their expectations.

Bleak prospects prevail for raising equity. "Investors have made relatively poor returns in the oil & gas sector over the past 4-5 years, with the exception of US unconventionals," Doyle said. Debt will remain cheap for investment-grades like Shell, but the high yield market has been in free-fall; while accessing bank debt now comes with greater scrutiny on projects. Apart from private equity, ...

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'FOB Australia index – rather than link to Asian hub'

Melissa Lindsay, Tullet Preborn's global head of LNG, sees an emerging FOB Atlantic and a FOB Australia price index, rather than linking the price of LNG in Asia to a trading hub in Singapore, let alone Shanghai.

Asked if new LNG projects will be developed in the next 10 years, underpinned by pricing at an Asian hub, she was rather sceptical.


M. Lindsay

"Pricing needs to be reflective of the greater region," she stressed, explaining "shorter term deals are done on a fixed price basis. But it's just about matching buyers and sellers base on a certain index."

Japanese buyers and some of the key players in China are "currently over-contracted, so they want to move around cargoes on a spot basis," she said at the IP Week in London.

Strikingly different terms for landed LNG into China

CNOOC's chief energy researcher Chen Weidong disclosed some details on pricing terms of landed LNG into China.

"We've bought LNG from Indonesia and Oz for over 20 years at prices around $4/MMBtu – while the latest contract signed with Qatar had a price of $17/MMBtu landed into China," he said with a weary smile when mentioning these strikingly different terms.

Though China now has 11 LNG import facilities up and running, equalling 40 mtpa of regasification capacity, the utilization rate of these facility ranges from a meagre 30% up to 60%.

Pipeline gas imports from Central Asia, as well as latest arrangements for two key piplines from Russia keep a lid on LNG imports. Moreover, the share of shale gas is meant to rise from currently 1% to cover 15% of China's gas demand by 2020.

Coal remains Asia's cheapest energy source, with IHS head of global steam coal David Price stressing that delivered coal price into Asia is under $3/MMBtu – a far cry from landed LNG prices above $9/MMBtu.

But the tide might be turning and Price suggests "a gas glut coming out of Australia could prove a 'genuine economic challenge' to coal in China." ■

AGENDA

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Doyle suggested project developers can seek support from trading houses like Vitol or Glencore which are starting to take exposure to upstream assets. Moreover, traditional EPC contractors like Siemens and GE are coming into the oil & gas space and are prepared to provide some funding.

Most LNG projects have so far been "robustly funded by Big Oil", with S-curves being used to guarantee returns. In contrast the latest US shale gale is "mostly driven by smaller-cap firms, so there is less resilience in the system," said Marc de Saint Gerand, assistant general manager at **Sumitomo Mitsui Banking Corporation.**

Aerial view of Kitimat, B.C., where Rio Tinto has struck a deal over use of the deep water port with LNG Canada

Turning to lower-cost resource plays

Shell's head of structured finance Mark Turner stressed IOCs are "deploying capital to lower-cost resource plays while scrutinizing the fiscal and regulatory regime of host countries." In Canada, the $40 billion Shell-led LNG Canada project in Kitimat, British Columbia, is expected to start up by 2021, if FID will be taken by 2016. The LNG tax regime in B.C., oil forward curves and cost of capital are scrutinized.

"We used to target a 15% return on capital deployed, but we are currently nowhere near that," he told the International Petroleum Week in London, stressing Shell's determination to cut costs so that it can continue to invest.

A **Barclays** delegate remarked that "given the oil price plunge it is rather easy for E&P companies to work on their unit costs."

Asked what else can be done, the panel agreed that the best way to stop cost overruns is arguably to make sure to have a proper Front End Engineering Design (FEED) in place before taking FID.

Amec Foster Wheeler chief executive Samir Brikho retorted by stressing "Most project partners who did a proper FEED work, have delivered their project on time and on budget.

"Financial partners are looking for companies led by a strong management with a good reputation in the industry, a sound track record and the ability to deliver on promises."

Seeking partners with deep pockets

Only around 5% of Shell's CAPEX tends to be raised from third parties, as the Anglo-Dutch major primarily works together with partners with a strong balance sheet. "Treating everybody in a project as a 'true partner' is vital for us," Turner said, "rather than using our balance sheet to bankroll others."

LNG exports from integrated shale gas & liquefaction projects used to be contractually linked to oil prices – a key difference between most Canadian projects and those along the U.S. Gulf Coast.

"With prices for JCC-linked LNG having fallen from $16 to below $11/mmBtu, even contracts that are nominally oil price-related are now being renegotiated or go to arbitration," **EY's** global oil and gas leader Andy Brogan said.

Some analysts fear that more than $100 billion of oil and gas-related projects could be cancelled, or delayed in the short term, due to the 50% fall in the price of crude over the past six months.

Though revenues can amount to over $300 billion a year for big trading houses like Vitol, profit-margins are razor thin and have shrunk to less than 1% on occasions. "Whoever has storage this year will win," analysts said, suggesting this might "not necessarily [be] traders – but oil companies too and even refiners."

Most US LNG plants will "never be built"

As the collapse in oil prices dampens demand for Henry Hub-indexed LNG exports, analysts at **Sanford C. Bernstein & Co.** warned most of the proposed US liquefaction capacity will "never be built."

The Canadian LNG province British Columbia, in particular, is likely to miss its goal of getting three liquefaction facilities in operation by 2020. Bernstein analysts see only one project by 2021 and a second by 2023.

Long-term price differences between oil and natural gas are converging, so hub-indexed US LNG has lost most of its competitive advantage.

Asked how low oil prices can go, Bernstein's senior oil and gas analyst Neil Beveridge said "We would say $40 is about the bottom; once oil prices go below that producers will start shutting in."

Any recovery will be determined on how quick companies can cut CAPEX and lower production but also how the demand-side response will be to record-low oil prices, e.g. end-customers might start to drive more. "The Saudis are pushing prices down to force the marginal producer out of the market, but we don't know if this will [also] be the strategy of Venezuela and Iran, let alone major E&P companies that extract shale oil and gas." ■

LNG North America

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Subscription included with
LNG Journal

Analysis: Will NDRC allow low oil prices impact gas netbacks in China?

Final stage of China's gas price reform is due to be completed before the end of this year, notably the increase of 'existing' city gate prices to a higher 'incremental' price. Given the oil-link of city gate prices domestic gas prices should drop substantially in H1'2015, analysts warn that the powerful National Development and Reform Commission (NDRC) may well block this to keep domestic gas netbacks attractive for the likes of PetroChina and Sinopec.

Ostensible links of China's city gas prices to liquefied petroleum gas (LPG) and high sulphur fuel oil (HSFO) would normally make gas prices react directly to the plunge in global oil prices. It is uncertain, however, whether the National Development and Reform Commission (NDRC) will allow this price reduction to feed through to consumer prices.

NDRC might view low oil prices as a short-term cyclical phenomena and thus retain high gas prices to ensure profitability for suppliers, according to Wood Mackenzie Asia analysts lead by Cynthia Lim.

Averting impact of the oil price plunge?

Opting-out of its own 'city gate pricing policy' during the period of low oil prices would help China's national oil companies (NOCs). Domestic gas netbacks would remain attractive and contracted imports could be delivered significantly below city gate levels.

PetroChina seeks to maximize profitability by accelerating domestic output and hold imports via the Central Asia pipeline to take-or-pay to mitigate high transportation costs of Turkmen gas. Sinopec, may reduce domestic production from the Ordos Basin in order to find a home for contracted Australian imports from PNG LNG and APLNG into its Qingdao regas terminal, as oil-indexed LNG prices are anticipated to fall throughout 2015.

However, any policy-driven obstruction of inherent oil-link of China's city gas prices to forgo reductions in domestic gas prices risks to slow down the coal-to-gas switching process in the power generation and industrial sector.

Gas use for power generation has increased by an average of 16% a year in the past decade. In 2014, however, gas demand growth slowed notably from over 13% in 2013 to around 8% last year.

"This was influenced more by cyclical factors. In addition to slowing GDP growth, evolving environmental policies, higher hydro output, mild winter weather in northern China and high domestic gas prices relative to oil were key factors that saw gas demand growth fall sharply," explained Gavin Thompson, WoodMac's principal analyst for APAC Gas & Power research.

In 2015, the government's decision on domestic gas price reform will be a key influence on demand, according to Thompson: "While we expect domestic demand growth over the next few years to return to historic levels, a swift return to double-digit growth may not be achievable without lower city gate gas prices."

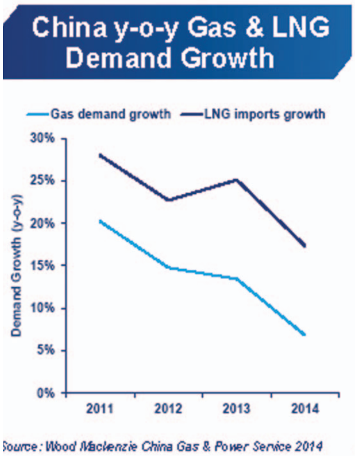
Hunger for energy fades more rapidly than GDP drop

2014 was a significant year for China as the pace of power, gas, coal and diesel demand fell more drastically than the slight GDP moderation – beyond analysts' expectations. A slowdown in industrial output subdued electricity needs while gas demand is on the rise driven by policies to shift from coal to gas generation in China's metropolis.

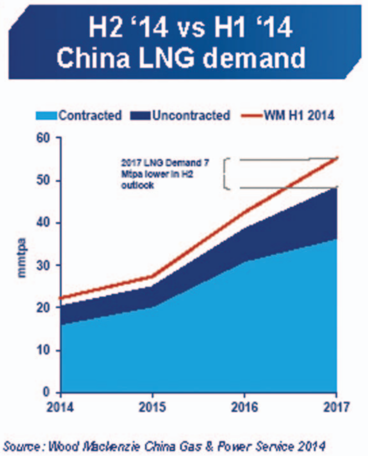
Gas demand is seen as 'cyclical' and expected to recover in less than two years' time, but electricity, coal and diesel "will see their demand outlook change notably over the long-term due to major structural changes in the economy and policy," according to Wood Mackenzie.

Regional patterns will also change with higher electricity demand growth to be concentrated in the China's western provinces where industrialization is still going strong, compared to a marked slowdown in its coastal regions.

Weakness in China's industrial sector, albeit short-term, is expected to keep a lid on electricity demand growth, particularly as many power producers are sitting on high inventory levels. Coal imports saw the steepest drop of all commodities, plunging 38% from December levels at 16.78 million tonnes, according to customs statistics.



Source: Wood Mackenzie China Gas & Power Service 2014



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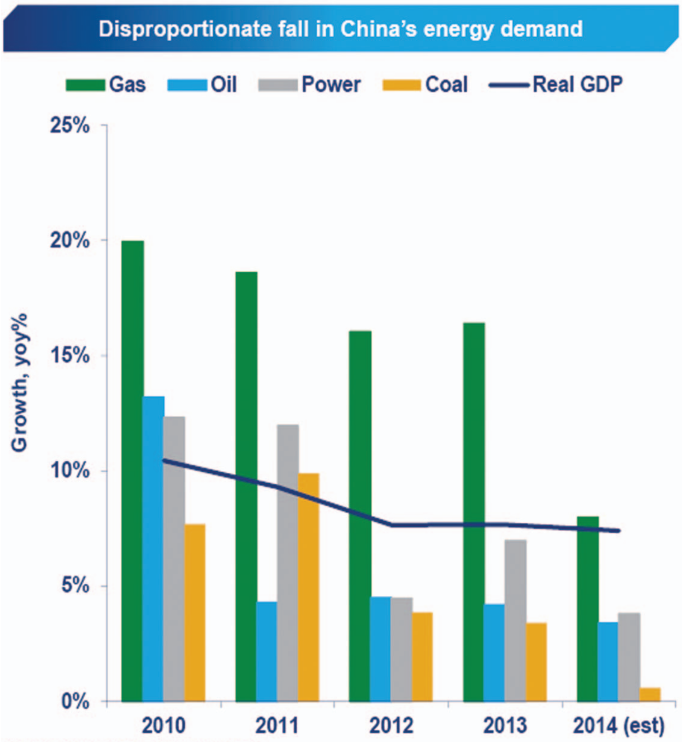

Source: China NBS, Wood Mackenzie

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Near-zero growth in coal demand for power gen

Measures imposed by the Chinese government to curb air pollution and improve energy efficiency have not only slashed coal imports but also reduced domestic coal mining. Wood Mackenzie figures show that the pace of annual coal demand growth slowed to 4-5% in 2012 and 2013, particularly in coastal markets, with near-zero growth in demand for power generation.

"Coal remains king in China but growth has been severely reduced, due to industrial weakness as well as cyclical weather patterns that saw higher rainfall boosting hydro output. Through the short-term, coal-fired generation will likely be muted by lower power demand, environmental policies and a rise in non-coal generation including hydro," Thompson said.

"Longer-term coal demand pace and patterns will be impacted by structural changes, with demand rising fastest from inland provinces and the acceleration of ultra-high voltage (UHV) transmission lines to export power to the coast." ■

Pricing reform meant to improve economics of LNG imports

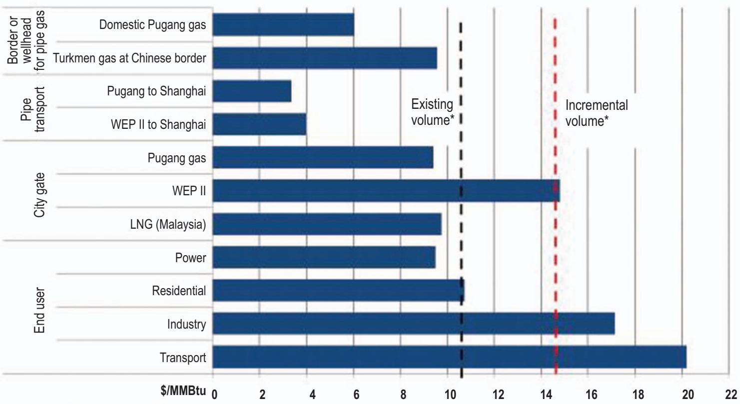
Keen to achieve higher gas penetration, China's State Council is targeting to reach a gas supply capacity of 400 to 420 Bcm by 2020. Last year's start of a gradual pricing reform has improved the economics of imports of LNG compared to pipeline gas, while strict environmental policies will enforce more gas use for power generation, writes Michael Chen, OIES visiting research fellow.

Despite the flurry of LNG regas terminals that have sprung up along China's coastline to meet peak gas demand, there is currently relatively low degree of medium and long term contracted LNG volumes. "Like other Asian LNG buyers, China will need to sign new LNG contracts for delivery in the early 2020s, if not sooner," Chen said, suggesting that like other Asian buyers it is eyeing to buy hub-indexed LNG from North America.

China's gas price reform has lifted average costs for baseline demand to $10.90/MMBtu, facilitating more LNG imports, but power producers see their profit margins squeezed as they have to continue selling electricity at low regulated prices. Under the new regime, prices of imported LNG will be fully liberalized, with prices for incremental volumes now hovering around $13/MMBtu, according to a FACTS Global Energy report.

OIES' Chen cautioned that "The speed at which the price of existing and incremental gas converge and tiered gas pricing is being introduced will have a strong impact on Chinese sectoral and regional gas demand, which is becoming increasingly sensitive to the economics of LNG and pipeline gas imports." Regions with strong economic growth and fewer fuel alternatives are more prepared to pay higher prices and pass through costs to end users.

Gas prices and tariffs along value chains to Shanghai, 2013



Note: The NDRC set the price ceilings for non-residential exisiting (2012 volume) and incremental gas (in excess of 2012 supply) for Shanghai on June 28, 2013.

Sources: China Customs Statistics, CEIC, NDRC.

Dilemma of one-sided reform

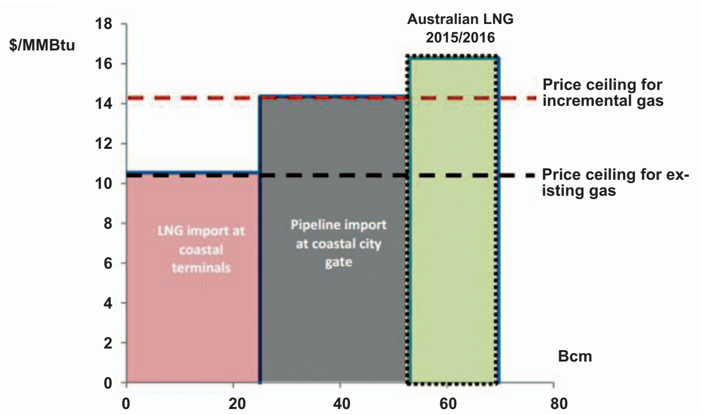
Some Chinese consumers, particularly power producers which account for 23% of total gas demand, consider the latest gas price hikes as 'too high'. They criticize the reform so far has only concentrated on lifting gas prices towards levels seen on global markets, while electricity prices remain unchanged to protect household customers.

As long as the electricity price remains tightly regulated by the Chinese government, many operators of gas-fired power plants are operating at a loss in light of the rising fuel costs. In many extreme cases, plants only operate during seasonal peak shaving periods and are left idle for the rest of the year.

"Moving forward, the Chinese government is facing a dilemma. On the supply side, producers and importers are eager to push to hike prices in order to compensate for higher exploration cost on domestic gas and reduce losses on expensive gas imports. On the demand side, Chinese consumers may increasingly have difficulties to afford higher prices. Following the increase on average price by some 15% in 2013, the rise in the average baseline demand price by 18% in 2014 made natural gas more and more expensive in China for non-residential users," the report reads.

Imports of LNG have become a reliable and flexible supply which contribute to peak shaving of power plants in the coastal provinces. The tide may, however, well turn against costly LNG once China can draw more on domestic shale gas supplies from the Sichuan and Ordos basis and if it proves economical to distribute Central Asian and Russian imports as far as Shanghai and Guangdong. ■

Gas import cost curve, 2013



Note: Price ceilings for incremental/existing gas are at Shanghai city gate. Price for new Australian LNG that China sources is estimated for its delivery at Shanghai city gate which takes into account the delivered price (assumed to have slope of 14-15 percent range), transport costs, regasification (and storage) charges and transmission cost to city gate (Stern, 2012).

Source: China Customs Statistics, CEIC, NDRC, stern (2012), author's calculation

Bear Head on track to have all permits by mid-2015

Canadian regulators have told stakeholders in Nova Scotia's Bear Head project, owned by LNG Ltd., that the project will not face major hold-ups and was on schedule to receive all permits by mid-2015.

LNG Ltd. has already applied to Canada's National Energy Board for a 25-year export licence for up to 12 mtpa. The Australian firm acquired the Bear Head venture as a partly developed import terminal.

Canadian Environment Assessment Agency had reviewed the project and concluded that the design for the proposed project would be substantially the same as that which was previously submitted and approved.

"Since some construction of the LNG facility has already taken place, the Canadian Environmental Assessment Act of 2012 does not apply to the LNG component of the project, and the proposed installed gas-fired power generation is not considered to trigger the 2012 Act since the project will not use natural gas to generate electricity," the agency stated.

To be located on the Strait of Canso in Point Tupper, Richmond County, Nova Scotia's first LNG export project will have roughly half the shipping distance to major European markets compared with US Gulf Coast ports.

LNG Ltd. intends to use feed-gas from the Marcellus Shale for liquefaction and export in addition to possible gas supplies from eastern Canada. To that end, it has asked the US Department of Energy for multi-contract authorization to export up to 503 billion standard cubic feet per year (bcf/y) by pipeline to Canada for use at the Bear Head plant.

The Bear Head parent company LNG Ltd is also developing the Magnolia project in Lake Charles, Louisiana.

Mind the Pieridae and H-Energy ventures

Though Bear Head might well be Nova Scotia's first project to export LNG, two competitors are keen to follow suit.

Pieridae Energy, meanwhile, is trying to set up a second Nova Scotia LNG export project in the town of Goldboro and has already signed a sales contract to deliver cargoes to the German utility E.on. Under the supply accord, Pieridae will deliver about 5 mtpa of LNG to E.on for 20 years into a number of locations in Western Europe.

Pieridae has planned an initial 10 mtpa of production and 690,000 cbm of storage in three 230,000 cbm tanks. The LNG project proposal also includes the development of a 180 MWs on-site gas-fired power plant.

Feed-gas for Goldboro LNG is slated to be delivered via the existing Maritimes & Northeast Pipeline, situated adjacent to the proposed liquefaction plant.

A third Nova Scotia LNG venture is planned by H-Energy, an Indian company operated by businessman Darshan Hiranandani. The town of Melford will be the likely location of this project, and Hiranandani said that his venture would be similar in size to the competing LNG project of Pieridae. ■

FSRU for Puerto Rico gets 'conditional nod'

The Aguirre floating LNG import facility to be located offshore the US territory of Puerto Rico has received a 'conditional go-ahed' from FERC's. In the final environmental impact statement, the regulator said any short-term impact could be minimized if recommended measures will be taken.

Excelerate Energy will provide a Floating Storage and Regasification Unit (FSRU) to serve as a gasport off the southern coast of the island in the northeast Caribbean. The Houston-based company is working on the FSRU project with the Puerto Rico Electric Power.

The FSRU would be deployed offshore the towns of Salinas and Guayama and would also have a 4-mile pipeline to provide regasified LNG supplies to the existing Aguirre power station in Salinas and would be Puerto Rico's second LNG import facility.

The existing EcoElectrica onshore LNG regasification facility is located about 35 miles east of the Aguirre plant. Excelerate has previously said it was aiming to have the Aguirre facility in service by the fourth quarter of 2015. ■

Repsol files for LNG export permit from Canaport

Spanish energy company Repsol has applied to the Canadian National Energy Board (NEB) for authorization to export LNG from its Canaport facility at Saint John. It intends to import 271 bcf of feed-gas from the US Northeast, process it into 5 mtpa of LNG, and export it from its project on the Atlantic coast of New Brunswick.

Three other LNG export ventures further north in Nova Scotia, also plan to use part of the surplus US shale gas production, combined with Canadian supplies.

Repsol specifically held on to the Canaport terminal when it completed the sale in January 2014 of its LNG liquefaction assets in Peru and Trinidad to Royal Dutch Shell for over $4 billion. In addition to retaining Canaport, the Spanish company also kept its North American Marketing and Trading business and has now formally decided to transform its regasification plant into a liquefaction facility.

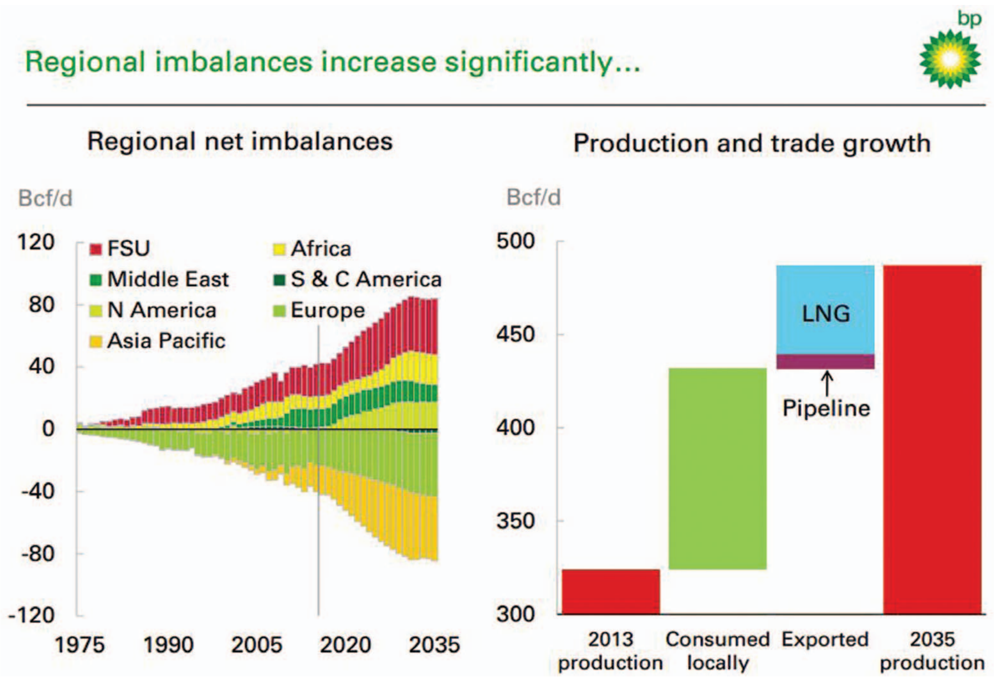
Canaport was developed by Canada's Irving Oil and Repsol as an import terminal when North America was short of gas before the shale boom. It opened in 2009 and Repsol in 2011 still managed to import 2.7 million tonnes of LNG, mostly cargoes from Trinidad and Qatar, into the glutted North American natural gas market.

Canada's pipeline natural gas exports to the US are set to hit their lowest level for 20 years, with NEB announcing another 5% drop in exports due to the shale gas glut across the border.

Some highly productive shale-gas plays in the US – such as Marcellus Shale that spans much of Pennsylvania, West Virginia and New York State – are located close to markets "traditionally served in part by Canadian pipeline exports," the energy board said. ■

LNG to become dominant in global gas trade

The overwhelming majority of the rise in traded gas volumes will be met through LNG, with supply growing almost 8% a year through the period to 2020. BP's latest Energy Outlook suggests that by 2035 LNG will have overtaken pipelines as the dominant form of traded gas.



The boost in LNG trade will over time lead to more integrated gas markets and prices across the world. It will also enhance diversity in gas supplies to consuming regions such as Europe and China. Improved energy efficiency and lower growth in Europe stands in sharp contrast to continuing economic growth in Asia, which accelerates the "shift in energy flows from west to east."

Inter-regional supply/demand imbalances are seen to double by 2035 – a key driver for global gas trade. According to BP, the expansion of trade is driven by Asia Pacific, where net imports nearly triple and account for almost 50% of global gas net imports by 2035.

A vast majority, namely 87%, of increased gas trade in Asia is done by shifting around LNG cargoes – on paper and in actual fact. Asia Pacific is forecast to overtake Europe as the largest net gas importing region in early 2020s.

Spurred by continuing shale gas growth, the U.S will become a net exporter of energy this year – adding to global LNG trade which over time will have fundamental impacts on global energy flows.

Natural gas is set to emerge as the fastest growing single source of power, as economic growth in Asia will drive global energy demand at an annual rate of 1.9% over the next decade, BP stated in its Energy Outlook 2035. Chief executive Bob Dudley forecast "gas will meet as much of the increase in demand as coal and oil combined."

Critics cautioned that global gas demand is rising less pronounced than before the slowdown of the Chinese economy. BP figures suggest that as China's level of productivity catches up with the OECD, its rate of growth is expected to slow from 7% per annum in this decade to 4% p.a.; India's growth moderation is more gradual: slowing an average 6% in the years to 2025, followed by 5% p.a. in the decade to 2035.

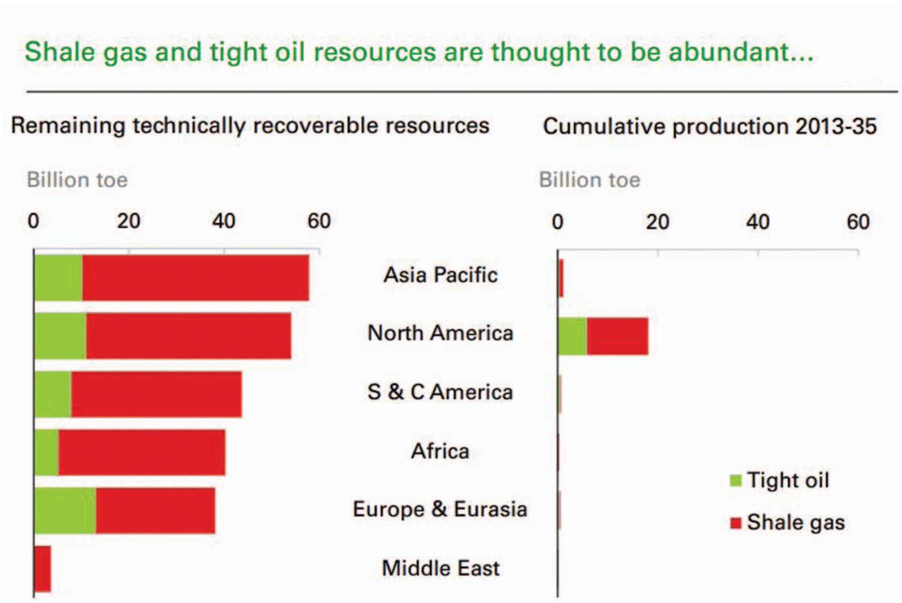
Shale gas, renewables to alter global energy mix

The world will still consume up to 1.9% more gas per year, according to BP analysts, with demand met by supply from the Middle East and Russia – as well as half from shale gas.

By 2035, North America, which currently accounts for almost all global shale gas supply, will still produce around three quarters of the total, BP analysts suggested. Shale oil and gas along with renewables will gain a larger share of the energy mix as an increasingly global gas market leads "to greater congruence in global price movements [for LNG]," the report reads.

However, growth in shale gas outside North America accelerates and by the 2030s overtakes North American growth in volume terms. China is the most promising country outside North America, accounting for 13% of the increase in global shale gas. By the end of BP's forecasting period, China and North America account for around 85% of global shale gas production.

"Fossil fuels are projected to provide the majority of the world's energy needs, meeting two-thirds of the increase in energy demand out to 2035. However, the mix will shift. Renewables and unconventional fossil fuels will take a larger share along with gas, which is set to be the fastest-growing fossil fuel," Dudley forecast. ■



Source: Resources data © OECD/IEA 2014

Total on the lookout for 'orphan LNG'

Buying LNG spot cargoes 'on spec' and selling it to 'opportunistic buyers', notably in India , is one of Total's strategies, according to senior advisor Guy Broggi.

Sources to snap up spot cargoes are plenty fold: LNG reloads at regas terminals, surplus LNG production from liquefaction plants, flexible volumes that can be bought on spec without fixed end-user, or divertible cargoes that are headed to whereever the price is highest.

"India is opportunistic as to LNG imports," Broggi said, but in contrast to that, Japan, South Korea and China used to prefer stable long-term supplies.

Japan long-term LNG proxy is 14.85% x JCC (n-3) - a, he disclosed, suggesting Korean buyers have renegotiated their Yemen LNG contract and are now paying around the same as Japan. "In Asia, it's all about not having to pay more than your neighbour," he suggested.

China pays less - they are "the best negotiator of all of them", according to Broggi. However, this is not surprising given the multitude of gas sources that Chinese NOCs can choose from: Pipeline gas from Russia or Turkmenistan and Kazakhstan, domestic shale gas or LNG imports either from Australia, the Middle East or the United States or eventually even from East Africa.

As for Canada, things look less promising. "It's getting a bit late. Canadian projects have lost their clients to the US," he commented. Project partners in British Columbia are hesitant to take FID and reconsider selling LNG on an oil-indexed basis. In Australia, meanwhile, developers rush to curb costs in the face for sustained low oil prices.

Alaskan LNG is still a bit of wild card, but Broggi stressed Exxon, Conoco and the Alaska government have signed a memorandum with Japan "and this LNG supply will come by 2020/22."

Alaska is set to eventually produce 20 mtpa, while Russia's ambitious Yamal LNG project has a nameplate capacity of 16.5 mtpa.

"In the northern Atlantic, there's a race and a bit of a battle for of tapping the artic - one of the last gas frontiers." ■

> "India is opportunistic as to LNG imports but in contrast to that, Japan, South Korea and China used to prefer stable long-term supplies."
>
> *Guy Broggi, senior advisor, Total*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Alaska: LNG export project competes with larger pipeline

Bill Walker, the Governor of Alaska, is considering construction of a stand-alone pipeline to transport larger amounts of North Slope gas in case the 20 mtpa Alaska LNG project failsto take final investment decision. "Whichever project is first to produce a solid plan, and conditions acceptable to the state, will get full support," he said.

His latest stance shows a more aggressive approach to oil and gas development and exports, which funds 90% of the state's discretionary spending. With oil prices half of what they were last summer, Alaska's hydrocarbon tax take has plunged by 80%.

Walker now calls for consideration to expand the Alaska Stand Alone Pipeline (ASAP), initially designed to supply gas to in-state residents, in order create a pipeline link to a small-scale liquefaction plant and export terminal. Crucially, he wants the state to take ownership of the project, suggesting this could boost state revenues.

"What it comes down to is this: We will work with the producers to continue to developing the AK LNG project," he said, suggesting the stand-alone pipeline can help gas buyers to "secure the opportunities the market offers."

Creating a fall-back option

Expanding the Alaska Stand Alone Pipeline is seen as a fall-back position should a proposed Public Private Partnership (PPP) with five oil majors for the large-scale Alaska LNG project not move forward.

Though partners in the 20 mtpa liquefaction project have filed a detailed daft of resources report to FERC, there are still questions over gas supply and environmental concerns.

Should Alaska LNG fail to advance, the Governor would have a fall-back position in the form of the large-scale standalone pipeline to bring natural gas 800 miles southward from the Point Thomson and Prudhoe Bay gas fields on the North Slope.

Walker recently appointed three new members to the Alaska Gasline Development Corp. Board to support his plans for an enlarged ASAP interconnector. The new board members are Rick Halford, Joe Paskvan and Hugh Short.

Alaska LNG – a PPP backed by Big Oil

The mammoth Alaska LNG project is backed by six parties, namely ExxonMobil Corp., ConocoPhillips, British Petroleum (BP), TranSCanada Corp. and Alaska Gasline Development Corp. and the state of Alaska itself.

The liquefaction facility, including three Trains and three storage tanks, is planned to be constructed on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula. Alaska LNG outlined that "the liquefaction facility will be capable of accommodating two LNG carriers." The size range of the tankers will be determined through further engineering study and consultation with the US Coast Guard.

The report filed to FERC cautioned that "due to the amount of wetlands, navigable waters, and open water present within the project area, it [Alaska LNG] will require coordination, and in certain instances regulatory permit filings with multiple federal agencies." It also specified potential mitigation measures.

> **"We will work with the producers to continue to developing the AK LNG project to secure the opportunities the market offers."**
> *Bill Walker, Governor of Alaska*

In addition to the liquefaction plant, the Alaska LNG venture will include the interdependent facilities, including a new large-diameter natural gas pipeline of around 800 miles in length extending from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production natural gas fields on the Alaska North Slope to Cook Inlet.

Drawing from 'at least 5' gas links

For the purpose of the resource reports a 42-inch diameter pipeline is assumed, it said. The mainline will include compressor stations, heater stations, meter stations, and various mainline block valves and associated ancillary facilities.

"Along the Mainline route, there will be at least five off-take interconnection points to allow the opportunity for future in-state deliveries of natural gas. The size and location of such interconnection points are unknown at this time," the report reads.

"None of the potential third-party facilities used to condition, if required, or move natural gas away from these off-take points will be part of the project."

Ancillary and auxiliary facilities will include access roads, helipads, construction camps, pipe storage areas, contractor yards, material extraction sites, and material disposal sites.

"Outside the scope of the project, but in support of, or related to it, additional facilities or expansions or modifications of existing facilities will be needed or may be constructed," it said. These other projects may be located at Point Thomson, Prudhoe Bay and the Kenai Peninsula. ■

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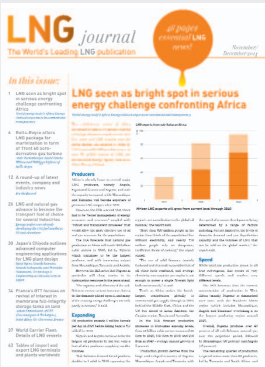

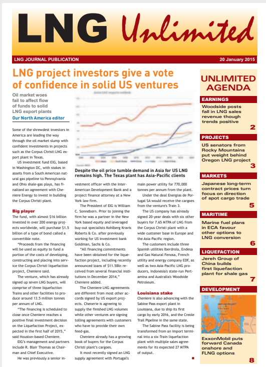

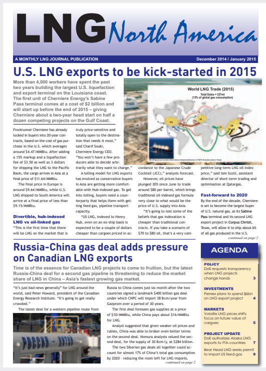

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