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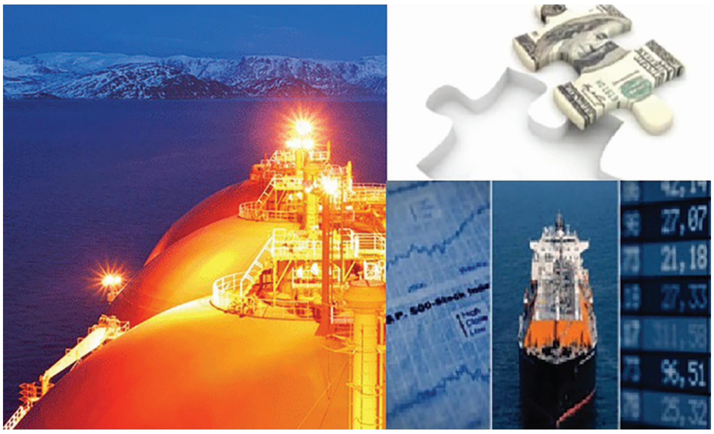
Offtake risk makes 2nd wave of US LNG projects slowly forthcoming

Challenges in securing long-term offtake agreements, as well as rising construction cost, have made the second wave of US LNG projects difficult to finance. Developers have to get creative, if not rather desperate, to raise financing and agree to shorter-term deals with smaller quantities on more flexible terms.



Short-term, flexible contracts come up for renewal more often which increases the risk contract cancellations, or buyers pushing for renegotiations. Smaller quantities of LNG offtake requires the owner of a liquefaction facility to handle and coordinate a plethora of such small, short-term contracts – exacerbating the risk of conflicting interests between multiple stakeholders.

Shorter contract length

Accelerating commoditization of global LNG market becomes apparent from the fact that the duration of supply contracts has nearly halved. For deals signed in 2017, the average contract lengths fell to 6.7 years – the lowest ever recorded – compared with 11.5 years in 2016, according to a report from New York-based energy consultants Poten & Partners. Buyers have signed dozens of short- and medium-term contracts rather than committing to offtake agreements that could underpin the construction of new liquefaction capacity needed to keep the market in balance by mid-2020s.

"This trend suited sellers who view the shorter contracts as a way to wait out the current soft market, and aggregators who have large volumes of LNG to sell over the next few years as US projects come online. But, with just two new LNG projects green-lighted over the past two years, concern is growing that the market may be undersupplied in the medium-term," analyst warn.

Financiers hesitate

With fever long-term offake deals agreed, much of the traditional ways of financing falters, which increases the risk that the construction of new capacity will lag demand growth and set the stage for tighter markets and higher prices in the future. "Pricing for short-term deals has come down as buyers have taken advantage of the abundantly supplied market and sellers have competed to secure outlets for their supplies," the report reads.

Financing, already hard to come by, is difficult to find for any new liquefaction project that seeks to add length to an already oversupplied global market. BNP Paribas, the French investment bank, has already pulled the plug on granting finance to companies that are primarily involved in oil and gas production from shale.

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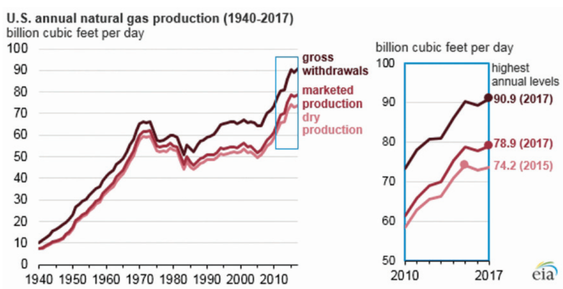
U.S. dry gas production goes from strength to strength

Dry natural gas production in the United States will keep growing over the next three decades, driven by demand from the industrial and electric power sectors. Beyond 2020, production is likely to grow faster than consumption, according to the EIA's Annual Energy Outlook 2018, with excess volumes to be exported to Mexico or sold on global LNG markets.



Overall US dry gas production is forecast rise from 73.6 billion cubic feet per day (Bcf/d) to reach 118 Bcf/d in 2050. In the High Oil and Gas Resource and Technology case, with lower production costs, gas production is seen to grow to 151 Bcf/d in 2050 – more than double the 2017 rate.

Most of the additional supply will come from the comes from the Marcellus and Utica shale plays in the Appalachian region, as well as supply of associated gas from the Permian region in Texas and New Mexico.

LNG exports quadruple

As a result of rising gas production the volume of exports, both via pipelines and as LNG, also increased. Total natural gas exports grew 36% in last year with LNG exports nearly quadrupling, which turned the United States into a net gas exporting in 2017 for the first time in nearly 60 years.

The United States became a net gas exporter in 2017 and the EIA expects both LNG and pipeline

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AGENDA

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S&P analysts warn this may impede other projects partner' ability to pay for construction, if more banks follow suit. "The repayment of project finance debt is from cash flow generated by long-term LNG offtake agreements with investment-grade companies; however, for a variety of reasons, these contracts are increasingly difficult to procure," the latest S&P Global Ratings report reads.

"The credit quality of new facilities could suffer if project finance structures are used but backed by shorter-term agreements (which introduce re-contracting risk) and/or merchant sales (and associated market risk) or include revenue counterparties that we rate below investment grade."

Sabine Pass, Cove Point LNG backed by long-term offtake deals

Cheniere Energy, in contrast, has financed its Sabine Pass terminal in Louisiana via 20-year take-or-pay contracts with credit-worthy buyers – setting a precedent for the industry.

Dominion Energy's Cove Point has similar long-term offtake agreements in place, and is on schedule to become the second US LNG project to start exports. In fact, all export projects that are actually progressing are based on long-term offtake, notably facilities being built in Freeport, Texas, and Corpus Christi, Texas.

Still, and seemingly against all odds, applications for new LNG export projects keep piling up on the table of U.S. regulators; but hardly any project sponsors managed to take a financial investment decision (FID) over the past 18 months.

Developers push back FIDs

Several developers delayed their decisions into 2019, or beyond, claiming they would soon sign up the necessary firm gas supply and purchase agreements to underpin their projects. But by when that may be, nobody can tell for sure.

In some cases, there is support from sovereign states: In the case of Alaska LNG, the state effectively took over the LNG project when the developers signaled a possible delay.

Remaining positive, S&P Global Ratings said the situation is no way not like liquefaction facilities will no longer be built in the United States. "It's just that the nature of these facilities could, or is likely to change. For example, we expect to see a greater number of smaller, more modular units," analysts said, "and potentially shorter-term contracts up to five years in length, with gas procurement arrangements changing as well."

Changes like these are expected to herald a host of new credit issues such as market and re-contracting risk, while possibly partly eliminating others – such as the counterparty risk. ■

Siemens' LNGo solution allows Altagas to monetize stranded gas

Dresser-Rand, part of Siemens Group, has commissioned an LNGo-HP (high-pressure) micro-scale natural gas liquefaction system for Altagas Ltd. in Dawson Creek, British Columbia, Canada. Producing approximately 30,000 gallons of LNG per day since January 25, 2018, the Dawson Creek facility allows Altagas to scale production in line with demand. The LNGo-HP system converts diesel and other fuels to natural gas, enabling users to monetize stranded gas deposits.

The micro-scale LNGo solution can be deployed in rough terrain or remote regions, eliminating the need to establish an expensive gas pipeline infrastructure or arrange for long-distance trucking of LNG from centralized plants to point of use. It can function as a decentralized solution where the requisite pipeline infrastructure is lacking, or as an onsite solution to reduce or eliminate flaring of petroleum gas at, for example, oil rigs or producing gas fields.

"We take pipeline natural gas and separate it into a feed gas stream and a waste gas stream. The waste gas is used to fuel the Siemens gas engine generator sets which power the LNGo-HP equipment. The feed gas is liquefied in the process to produce LNG," explained Michael Walhof, Sales Director for Distributed LNG Solutions for the Dresser-Rand business.

For the Altagas project in Dawson Creek, Siemens' scope of supply included one LNGo-HP system, site civil works, building construction, mechanical and electrical integration, commissioning, startup, and operator training. The LNGo system consists of modules which include two Siemens gas engines, two Dresser-Rand MOS reciprocating compressors, three Siemens MV motors, Siemens variable frequency drives, and associated auxiliaries. The plant, with a footprint of approximately 2,500 square meters, was deployed directly at the site. ■

LNGo system installed for Altagas in Dawson Creek, BC

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exports to Mexico will continue to increase, largely due to rising demand from Mexico's gas-fired power plants. After 2030, however, pipeline exports to Mexico are expected to gradually decrease as Mexican energy reforms take hold and production in the country reverses its current declines.

LNG exports are forecast to rise through the 2020s as more export terminals come online, following the opening of the Sabine Pass and Cove Point LNG export terminals. The EIA cautions, however, "U.S. LNG exports level off as U.S.-sourced LNG will become less price-competitive with increasing LNG supply from other global suppliers."

Henry Hub spot price seen below $6/MMBtu

Natural gas prices will stay largely unaffected by the continuous rise in supply. "Near-term production growth across all cases is supported by growing demand in an environment of low and stable natural gas prices in both domestic and international markets;" AEO2018 report states.

Looking at the forward curve, the EIA says it expects Henry Hub spot natural gas prices to remain lower than $6.00/million British thermal units (in 2017 dollars) through 2050.

Demand in the power sector is forecast to rise by another 4% from current levels to reach 35% by 2050. Still, the U.S. industry keeps consuming more natural gas than any other sector, and demand growth outpaces that of all other sectors. Industrial gas demand (including fuel used for drilling operations as well as LNG feedgas) is forecast to rise by 34% in the AEO2018 Reference case – from 9.8 Bcf/d in 2017 to 13.2 Bcf/d in 2050. ■

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South Korea’s LNG demand to fall before growing again post 2025

Initial optimism of global LNG suppliers that South Korea’s new electricity policy might lead to higher demand growth has been replaced by the recognition that more needs to be done for natural gas to replace coal and nuclear in Korea's power generation mix. The 13th Long-term Natural Gas Supply Plan for 2018 to 2031, released by the Government on April 5, anticipates LNG demand to reach 40.5 million tons (Mt) by the end of the forecast period, up just 3 Mt from 2017-levels.

While the 8% growth over 14 years looks disappointing, the latest forecast is already a major upgrade over the 12th Natural Gas Supply Plan which had anticipated gas demand to reach 35 Mt by 2029. Indeed, analysts expect Korea’s gas demand is forecast to fall before growing again post 2025, mainly due to the additions of coal and nuclear capacities between now and 2023.

“Our analysis forecasts 4 GW and 5 GW net additions (new capacities minus retirements) for coal and nuclear respectively over the next five years. These new builds are already under construction and approved under the 8th Electricity Plan,” said Wood Mackenzie principal analyst Kiah Wei Giam. “With the electricity market facing oversupply over the next few years, it will be even harder for gas to displace coal or nuclear based on pure economics,” he commented but the Government's policies limiting coal or nuclear generation will help to alter the power mix.

In the 8th Plan, all coal units that are over 30 years of age are required to shut down in the spring period when electricity demand is low. Based on WoodMackenzie analysis, even with gas-friendly policies in place, gas demand will still decline to hit a trough of 34 Mt in the 2022/23 period.

Post 2014, however, gas demand will turn the corner as 4 GW of coal and 5 GW of nuclear are retired between 2024 and 2031. Moreover, as per the 8th Electricity Plan, electric utilities are not permitted to add any new power generating units based on coal nor nuclear beyond those that have been already approved.

The shortfall in renewables energy additions could prompt yet another upside to gas demand. Solar and wind generation was expected to grow by nine times between 2017 and 2031 but even if this increase will materialise it is still insufficient to meet electricity demand growth. The government of President Moon targets renewables to account for 20% of the electricity generation by 2030 while WoodMackenzie forecast the share will only reach 15%.

“As such, gas will be needed to make up for the shortfall; hence we expect gas demand to reach 42 Mt by 2031, around 2 Mt higher than the government's forecast,” Mr Giam commented. While the latest gas plan does not live up to early expectations, it is more positive for gas than the 12th Plan. The 13th Plan also confirms the increasing role of gas in the electricity generation mix as outlined in the 8th Electricity Plan.

Lowering of tax on LNG imports or introducing environmental dispatch which includes emission costs would increase the competitiveness of gas and, if implemented, will provide upside to gas demand, he recommended, concluding “President Moon may not have delivered on his electoral promise to substantially increase the share of gas in overall generation mix, but he has successfully laid the foundations for gas to take centre stage in South Korea's future energy mix.” ■

Pyeongtaek LNG import terminal

Mexico advances gas infrastructure build-out

Mexico is developing a series of privately-owned pipelines a floating LNG import facility, as part of a historic build-out of the nation’s gas infrastructure. State-owned Cenagas, operator of Mexico's main l gas transmission network, is overseeing the programme and the energy regulator CRE, is providing technical guidance.

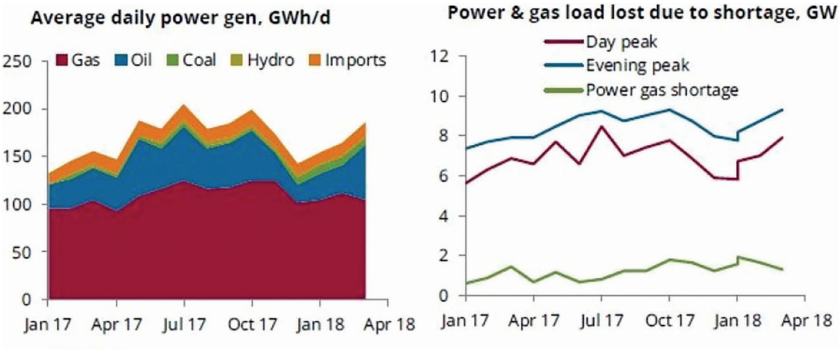
Five inter-connection projects would be linked to a planned floating storage and regasification unit (FSRU) and also to the national pipeline network. Two further interconnectors are being built by Cenagas and the CRE to ease natural gas shortages in the southeast, namely on the Mayakan pipeline serving consumers on the Yucatan Peninsula.

The other key project is a 390 MMcf/d link to the planned Pajaritos FSRU venture led by state energy company Pemex at Coatzacoalcos in the state of Veracruz.

A tender is being conducted for the charter for three to five years of an FSRU LNG vessel and the construction of a 14-kilometres pipeline connected to the national network. According to Cenagas, “any new capacity will be made available to the market through an open season.” ■

Bangladesh started importing LNG in mid-April

Crippling gas supply shortages have become a thing of the past in Bangladesh as the country started importing LNG. The maiden cargo arrived on April 23. Going forward, Petrobangla seeks to secure attractive short-term deliveries and snap up spot LNG cargoes – some of them might well carry liquefied shale gas from U.S.



Source: BPDM, Energy Aspects

Reacting to crippling fuel shortages, Bangladesh has been active to expand its LNG import capability: Two FSRUs with more than 3 mtpa capacity will be in place by February 2019, and another three 1.5 mtpa LNG import barges by March 2019.

Five new FSRUs under construction

Moheshkhali FSRU (3.5mtpa) will be the country's first LNG import facility, scheduled to dock on 23 April, laden with a Qatari cargo. Summit Power is developing a 3.75 mtpa FSRU also offshore Moheshkhali which is due operational in February 2019. Furthermore, two small-scale FSRUs of 1.5 mtpa each were agreed to be developed at the port of Chittagong in September 2017, backed by the trading houses Gunvor and Trafigura.

Given the timings for start-up of those various FSRUs and combined-cycle gas turbine (CCGT) power plant projects, Energy Aspects forecast LNG imports of 2.7 mtpa in 2018 and 7.0 mtpa in 2019.

"With this expected level of LNG imports, gas shortages at current levels will be resolved," Sikorski commented, pointing out Bangladesh has all but secured contracts to import around 7 Mtpa and is in advanced negotiations for another 1.25 mtpa.

LNG imports designated for power sector

The power sector currently is Bangladesh's biggest single gas user, responsible for around 1.1 bcf/d (41%) of annual consumption for grid power companies and another 0.44 bcf/d (16%) used by industry for onsite gas-fired generators.

Through to 2020, electricity demand is forecast to grow by around 8 TWh/y each year, taking it 22 TWh/y higher than in 2017. Of that incremental demand growth, coal will add 9.1 TWh/y of electricity supply, meaning that gas-fired plants will have to supply 12.6 TWh/y more power than in 2017. According to Energy Aspects calculations, this will result in additional gas demand of 2.4 bcm in 2020, compared with 2017-levels, if all of the new gas-fired plants are operating baseload.

Though LNG imports will bring some relief, increases in gas-fired power generation capacity are likely to be limited to 1.0 GW in 2018, and 1.4 GW in 2019.

Alleviation of prevailing gas shortages in power generation could add some 0.2 bcf/d to gas demand, says lead analyst Trevor Sikorski. "The biggest impact," he says, "would be felt in a significant reduction in oil-fired generation, which is the second-biggest fuel source in Bangladesh."

In its latest country report, Energy Aspects has identified 11.5-GW of projected gas-fired capacity of which 2.7 GW is under construction, plus 14 GW of projected coal-fired capacity and a 2.4 GW nuclear power project in Rooppur. Assuming all projected new gas generation capacity will be built this would herald an annualized 2 mtpa of LNG import demand.

Further incremental rise in demand is possible, but would require either a decline in domestic production, expansions in industrial gas demand or further expansions of gas-fired power. "All three of these are likely," he said but cautioned "the main headwind to growth in gas demand is the addition of coal-fired power, although only 1.3 GW is expected online in the next two years." ■

India's LNG imports surge despite soaring costs

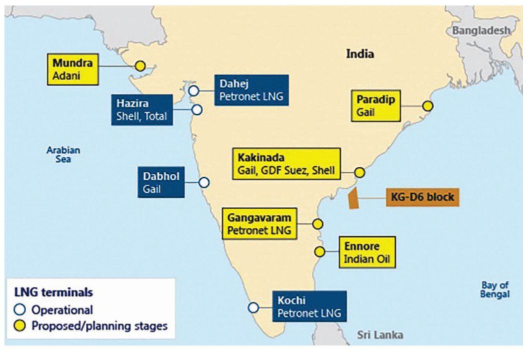
Regardless of soaring costs, LNG imports by India increased 16.8% in March compared with the year-ago period. Supply from Qatar and Nigeria was complemented by the first shipment of US LNG on March 30 – the start of a 20-year supply contract between Cheniere Energy and Gas Authority of India (GAIL).

Costs for LNG cargoes delivered to India's three main import terminals – Dahej, Hazira and Dhabol – have jumped 50% to around $900 million, compared with $600 million in March 2017. Supplies amounted to 1.86 million tonnes of LNG, compared with 1.59MT brought in the same month last year, according to the figures from the Indian Ministry of Petroleum and Natural Gas.

"LNG import for the financial year 2017-18 was the highest ever import figure for the fuel," the ministry stated, adding that costs for LNG purchases from April 2017 to March 2018 were $7.8 billion, significantly more than the $6.1 billion spent in FY2016-17.

India's gross domestic production of natural gas, however, did not grow with the same pace as costs. For the month of March this figure was 2.78 Bcm, a rise of 1.18% compared with 2.75 Bcm in the same month of 2017. The cumulative domestic natural gas output for fiscal 2017-2018 was 2.35% higher at 32.64 Bcm vs. 31.89 Bcm in the previous fiscal year, the ministry reported.

Looking ahead, the ministry suggested that LNG imports could have been higher if more destinations on India's east coast were available. The government is backing the development of a more comprehensive natural gas pipeline network as a precondition to shift India's energy mix from coal to cleaner-burning natural gas, and renewables. ■



India's operational and proposed LNG terminals

Tellurian sets aside $280m for executive bonuses

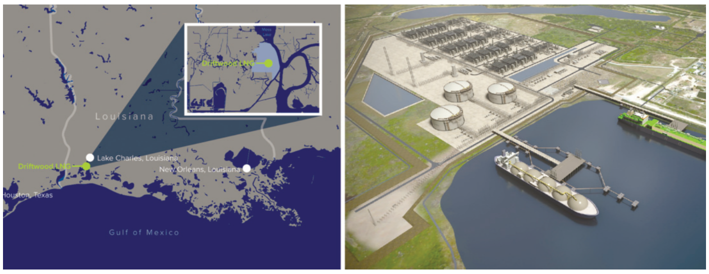
Tellurian Inc., the developer of the Driftwood LNG project, has set aside a pool of around $280 million for executive bonuses, including up to $35 million for CEO Meg Gentle as the construction work proceeds near Lake Charles in Louisiana.

Gentle, a former employee of Cheniere Energy just as Tellurian chairman Charif Souki, would receive $14M after the first phase of the Driftwood project is completed, followed by three other bonuses, each of $7M, for the next three phases of development.

"The aggregate bonus pool of cash incentive awards for employees and consultants of Tellurian or its subsidiaries is up to $280 million in connection with the development of Phases 1 through 4 of the Driftwood facility pursuant to the four EPC contracts," Tellurian in a filing to the Nasdaq stock exchange.

Lined up for big a pay-out is also Chief Operating Officer (COO) Keith Teague, whose four-installment bones payments will amount to a total of $8 million. Two other senior executives - Daniel A. Belhumeur, General Counsel and Antoine J. Lafargue, Chief Financial Officer (CFO) - could receive up to $6 million each under the bonus plans. Khaled Sharafeldin, Chief Accounting Officer, is in line for a phased smaller payment of $1.8 million.

Cash incentive awards to the company's named executive officers are set forth in connection with the development of Phases 1 through 4 of the Driftwood LNG facility. 25% of the award allocated to any Phase of the Driftwood facility will vest and become payable on each of the first, second, third and fourth anniversaries of the date on which a notice to proceed is issued.



Map of Driftwood LNG

FID targeted for H1-2019

A FERC authorization deadline is set for January 2019, allowing Tellurian to make a final investment decision (FID) and begin construction of the Driftwood plant in the first half of 2019.

The Driftwood LNG facility will consist of six Trains and around 27 million tonnes per annum (mtpa) of output – exactly same capacity as Cheniere's Sabine Pass plant, which was developed by Tellurian Chairman Souki when he was Cheniere CEO.

Bechtel, the engineering, procurement and construction contractor for Driftwood LNG, has also made a $50 million investment in the company. ■

Chart Industries back to profits in Q1-18, aims for $1bn sales

Chart Industries, the US LNG and energy equipment maker, has returned to a first-quarter profit following internal restructuring and amid a rise in its order-book. Order activity has risen 53%, or $111.4 million ($74.4 million excluding Hudson Products) above the first quarter of 2017," said Chart with reference to its acquisition of rival Hudson.

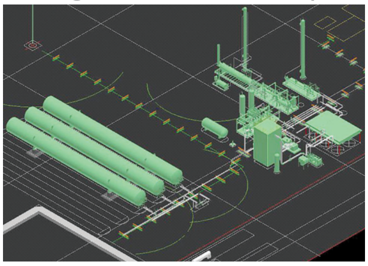
First quarter 2018 orders in Energy & Chemicals (E&C) segment were $93.7 million, inclusive of $37.0 million from Hudson Products, and sequentially an increase of 24.6% compared to the fourth quarter of 2017. This is the fourth quarter in a row with E&C order levels above $60 million. The natural gas and petrochemical markets continue to be strong, and LNG FEED and engineering activities continue to strengthen.

"The first quarter of 2018 continued to reflect the strong demand seen in 2017 for natural gas projects in both petrochemical and LNG export, with equipment orders received primarily for the West Texas Permian Basin," Chart said in a statement.

Bill Johnson, Chart's President and CEO, commenting on the results, said: "We are pleased with the start to 2018, both from a market and order perspective as well as the productivity results reflected in the margin in each of the segments.

"The strategic review of our oxygen-related product lines further supports our continued focus on analyzing our capital allocation and executing on our organic and inorganic key growth areas in core cryogenic equipment," he added.

Orders in the company's E&C segment came in 24.6% higher over the fourth quarter of 2017 and included four orders greater than $2 million each. E&C segment sales of $89.9 million ($46.6 million excluding Hudson) were down 1.5% compared to the fourth quarter of 2017 and up 16.7% versus the first quarter of 2017. "The year-over-year sales increase is driven by gas demand, in particular in the air-cooled heat exchanger product line," Chart said.



Scheme of Chart's nitrogen cycle liquefaction technology

First quarter 2018 orders in D&S of $170.4 million reflected an 11.2% order growth over previous quarter, driven by continued strength in packaged gas and LNG vehicle tanks. D&S sales decreased $14.1 million to $136.1 million compared to the fourth quarter of 2017, and increased $22.9 million compared to the first quarter of 2017.

"Year-over-year increases are driven by strength in United States packaged gas, China LNG trailers and vaporization stations, and European standard tanks," Chart said. ■

Works on Lake Charles LNG pushed back to Nov-2019

Lake Charles LNG, the liquefaction project owned by the U.S. pipeline company Energy Transfer, has asked regulators to extend the deadline for the start of construction to November 2019.

"Most of the regulatory prework and notifications to complete filings have now expired," Energy Transfer noted in its letter to FERC. A draft environmental impact statement was in September 2015 for the Lake Charles export venture to produce 16.5 mtpa of LNG.

Project owner of Lake Charles LNG is the US pipeline company Energy Transfer which, in addition to entering an export venture with Shell also signed an accord with Korea Gas to study the feasibility of joint participation in the Louisiana venture. Shell had gained a stake in Lake Charles's reserved liquefaction capacity from its takeover of BG Group. ■

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BHP Billiton pulls out of US southwest shale basins

Australian commodities company BHP Billiton is continuing to exit its onshore assets in the southwest of the United States, and is awaiting bids. "We expect to receive bids by June 2018 and proceed with negotiations to potentially announce one or several transactions in the first half of the 2019 financial year," BHP said.

In its nine-month operational review to March 2018, BHP Billion disclosed data rooms for all fields and mid-stream assets are now open and in parallel. "We continue to explore potential asset swap opportunities and exit via demerger or an Initial Public Offering," it said. In total, BHP Billiton's the US shale assets are estimated be worth at least US$10 billion.

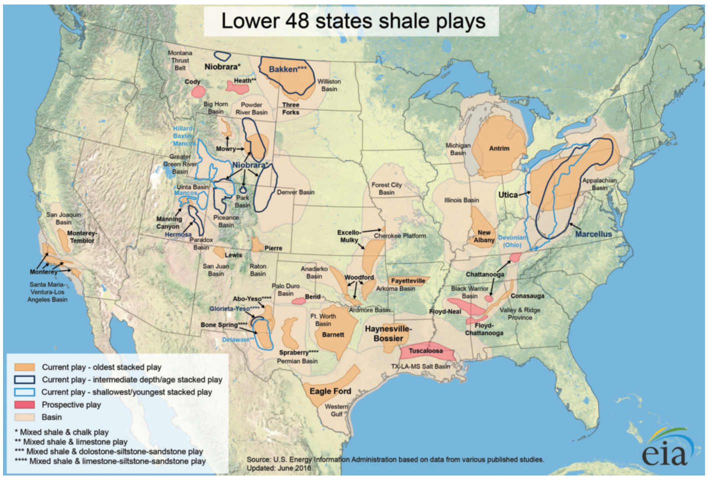
BHP holds around 838,000 net acres in the Eagle Ford, Permian, Haynesville and Fayetteville, and also holds assets in the Haynesville and Fayetteville shale plays. Moreover, the Australian company has drilled wells in liquids-rich areas of the Eagle Ford and Permian basins.

In the Permian Basin, spanning West Texas and the southeast of the US state of New Mexico, BHP said it continued to see strong results from larger completions. "We expect rig count to remain unchanged through the June 2018 quarter as we focus on meeting hold by production obligations and progressing sub-surface trials," said BHP.

In the Eagle Ford shale in South Texas, early trial results from wells with longer laterals in the Hawkville have exceeded expectations and early results in the Austin Chalk horizon have been positive. "During April 2018, we reduced our rig count from three to two and this is expected to remain unchanged during the June 2018 quarter," BHP added.

In the Haynesville Shale, the incorporation of larger choke settings in all new wells has significantly increased volumes, and longer laterals and larger completions have also outperformed expectations. In the Fayetteville shale area, the Australian company said it continues to assess the potential of the Moorefield horizon based on data from the new non- operated wells.

Looking ahead, BHP said its petroleum capital expenditure plans remained unchanged at around US$1.9 billion for the 2018 financial year. This includes conventional spending of US$800 million, focused on high-return infill drilling opportunities in the Gulf of Mexico, the LNG life extension project at North West Shelf and investment in the Mad Dog Phase 2 project in the Gulf of Mexico. Onshore US capital expenditure of US$1.1 billion will be on the drilling and completion activities to support value in the exit process and meet hold by production obligations. ■



Dominion on acquisition spree to become major US utility player

Dominion Energy, owner of the Cove Point LNG facility in Maryland, is pulling out all the stops to acquire Scana Corp and its South Carolina natural gas and power assets. Regulatory approval for the merger is still pending. Now Dominion put forward a study, saying the merger would bring a $18.7 billion boost to the economy of South Carolina.

Dominion three months ago put forward a $14.6 billion takeover bid for Scana in an all-stock transaction just when it was about to become the second US LNG exporter with its Cove Point plant, now in commercial operation. For Scana, the Dominion bid helps to absorb some of the costs of a failed South Carolina nuclear project.

Now Dominion put forward a study, carried out by economists at the Darla Moore School of Business, that elaborates on plans to provide direct cash payments and lower electric rates to SCE&G customers. These measures, as well as the additional benefits from cash payments, are estimated to boost the economy of South Carolina with more than $18.7 billion.

Render of Cove Point LNG terminal in Maryland

Merger expected to boost local economy

The estimated rise in economic output is based on an economic multiplier, or ripple effect, of approximately 1.49, according to the report. Five South Carolina counties are estimated to benefit more than $1 billion each, with the city of Charleston likely to see the greatest benefit, at $4.9 billion.

"The benefits of the Dominion Energy proposal go well beyond the immediate value of the $1.3 billion in cash payments to SCE&G electric customers," said Thomas F. Farrell, II, Dominion Energy Chairman, President and CEO.

"The payments and the extra money in customers' pockets from the lower rates will flow into the local economy in the form of billions of dollars in increased retail sales, new jobs, added wages and business investment," he added.

Cash payment to SCE&G customers

On top of the cash payments, equal to about $1,000 for the average SCE&G electric customer, Dominion proposes to reduce electric rates by about 7 percent after the merger closing.It also would absorb $1.7 billion in costs for the abandoned V.C. Summer nuclear project and purchase a natural gas-fired power station at no cost to customers.

Both players are in the process of obtaining regulatory approvals for the merger.

Green light has already been given from the Georgia Public Service Commission, while Federal Trade Commission granted early termination of the 30-day waiting period under the federal antitrust laws.

The merger is also contingent upon approval of Scana's shareholders, review and approval from the Public Service Commissions of South Carolina and North Carolina and authorization of the Nuclear Regulatory Commission and the Federal Energy Regulatory Commission (FERC). ■

Trend to decentralized power in Asia spurs LNG demand

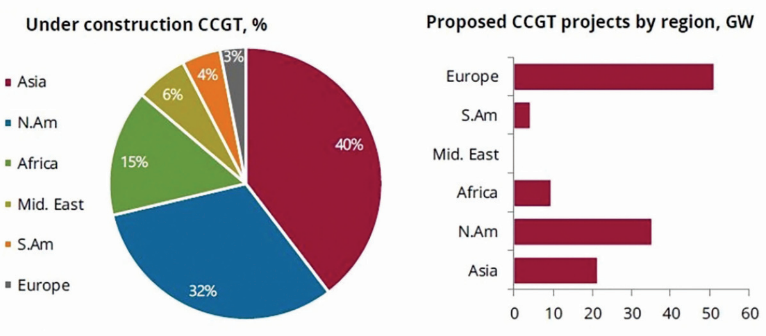
Gauging incremental gas demand, derived from new gas-fired power plant projects worldwide, Energy Aspects pointed out that most of Asia's new capacity is "supportive of additional LNG demand," while North American projects are "all likely to be fed by local shale gas. Most new CCGTs, however, are being built in gas-rich countries.

A big chunk of the new gas capacity is going into countries where gas is a local resource. Shale gas across North America or new developments of conventional gas fields in countries like Egypt have sparked new developments of combined-cycle gas turbine power plants. Moreover, persistently low gas prices in the U.S. are pushing coal out of the power generation mix.

It is only in some isolated regions in countries like Brazil, and for decentralized power project in Asia, where gas demand from the power sector is likely to be met by LNG.

Worldwide, Energy Aspects has verified some 85 MW of gas-fired power plant projects (with >100MW capacity) – predominately CCGTs – that are currently under construction. The lion's share of these projects, or 34 GW, is being realized in Asia, followed by North America where both the United States with 20 GW and Mexico with 6 GW have "healthy build-out programmes.".

Identifying plants with a direct impact on global LNG markets, around 37 GW of gas power projects is under development in countries that are currently net LNG importers. ■



Source: Various, Energy Aspects

Shell to supply LNG for Hong Kong power plant

CLP Power, developer of a new unit at Black Point Power Station (2,500 MW) in Hong Kong, has selected Shell to supply LNG to fuel the mega plant. The new 600 MW unit is scheduled to start operations by 2020, according to CLP Power's latest annual report, with LNG to be imported via a floating storage and regasification unit (FSRU) moored just south of Hong Kong.

CLP Power's new unit at Black Power Station comes at an estimated cost of HK$5.5 billion ($701.4 million), according to the company's 2017 annual report. To advance this regas part of the venture, CLP is currently undertaking an environmental impact assessment of the Hong Kong Offshore LNG Terminal project.

The integrated LNG-to-power project is part of a government initiative to shift Hong Kong's energy mix away from coal towards natural gas. Turning to LNG, rather than pipeline gas, is a relatively new move for state-owned CLP Power which used to rely nearly entirely on supply of pipeline gas from China.

Back in 2008, CLP scrapped plans for a $1-billion LNG import plant after China offered an attractive deal to renew a gas supply contract for another 20 years. But things started to change when LNG prices in Asia started to fall with the growing influx of supply from Australia, Qatar and flexible cargoes from the United States.

Black Point Power Station (2,500 MW) is owned by Castle Peak Power (CAPCO), which is 70% held by CLP Power and 30% by CSG – one of China's state-owned energy companies with connections to mainland gas importers.

CSG had initially envisaged building a pipeline that would allow Black Point Power Station to source fuel through the Second West to East Gas Pipeline (WEPII). The operators were first looking for new supply sources following the depletion of reserves at the Yacheng 13-1 gas field offshore Hainan Island, which used to be the only source of gas supply for Hong Kong's mega gas power station. ■

U.S. May cargo deliveries

The 155,900 cubic metres capacity "Clean Planet", operated by Dynagas, will deliver a cargo on May 1 to the Argentine Bahai Blanca import terminal in the southwest of the province of Buenos Aires from the US Sabine Pass export facility in Louisiana, owned by Cheniere Energy. The 176,300 cubic metres capacity vessel "Rioja Knutsen" will deliver a shipment on May 13 to China's Dalian terminal, operated by PetroChina in the northern Liaoning Province, from the US Sabine Pass plant.

US LNG exports rise

US LNG exports increased in the week from the Sabine Pass liquefaction plant in Louisiana, owned by Cheniere Energy, with six vessels carrying a combined 21.6 Bcf of natural gas departing the facility through April 18 and a seventh vessel with 3.8 Bcf lifting a cargo, according EIA data. The second US export plant now on stream, Dominion Energy's Cove Point plant in Maryland exported its first contractual cargo on the carrier "Adam LNG" with carrying capacity 3.5 Bcf. The EIA said the vessel left the Chesapeake Bay facility on April 16. It is scheduled to be in the East Mediterranean at the start of May, according to shipping data.

Sempra Mexican plans

Sempra Energy, the California-based utility transforming its Cameron LNG terminal in Louisiana and Costa Azul facility on the Pacific coast of Mexico into export plants, said it was scaling back its Mexican liquefaction plans. The Sempra Mexican subsidiary, IEnova is now looking at a small-scale plant with 2.5 mtpa of output by around 2023 instead of a larger plant constructed later with up to 12 mtpa of capacity and closer to the size of Cameron LNG. Sempra is also planning to build another export plant along the Sabine-Neches Waterway at Port Arthur, Texas.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Zhang Jia-Hua
Operations Team Leader
Baotou Lu Ding Natural Gas Co. Ltd.
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