Oil and Gas News Briefs
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Unsold LNG will hang over market to mid-2020s, analyst says

(Sydney Morning Herald; Dec. 7) – Though the oil market is in dire straits, the liquefied natural gas market is worse, experts say. Hanging over the market for the next several years are large volumes of U.S. LNG exports in search of end consumers. Consultancy Facts Global Energy says 25 million to 35 million metric tons of the 65 million tons a year of U.S. LNG export capacity under construction has been sold to middlemen, traders or portfolio players such as BG or Mitsubishi, which still need to sell the gas.

"Portfolio sellers and traders are not end users, they must find buyers," FGE founder Fereidun Fesharaki said. In addition, about one-third of Qatar's LNG export capacity is unsold, while the three big Chinese national oil companies and one Indian national oil company have switched from buying to selling as they seek to resell LNG they have committed to buying but no longer need, according to FGE.

That means about 70 million tons a year of LNG still needs a buyer, weighing on the oversupplied Asian market to the mid-2020s, the consultancy said. Fesharaki describes those holding the contracts as "desperate sellers" that will provide stiff competition for producers seeking customers for new LNG projects. Fesharaki names only three new projects that could move forward in the next few years: Anadarko's Mozambique venture; expansion in Papua New Guinea; and Petronas' project in Prince Rupert, B.C.

Lack of new projects in 2020s could drive LNG prices higher

(Forbes columnist; Dec. 5) – At first blush it’s easy to skim the news of Indian LNG buyer Petronet negotiating a lower price for deliveries from Qatar’s RasGas and miss its significance. But the news is profound and typifies the radical shift that LNG markets are going through after the period of limited supply and exorbitantly high prices (2011-2014) post the March 2011 Fukushima nuclear disaster and subsequent shutdown of all of Japan’s nuclear reactors and that country’s over-reliance on LNG.

During that period, the world’s largest LNG importers, particularly Japanese and South Korean utilities, were at the mercy of LNG producers. Spot prices for the fuel breached the $20 per million Btu mark in early 2014, while producers also locked in handsome long-term contact prices based on crude oil prices. The pendulum has now swung the other way and LNG producers are now at the mercy of buyers, hence the significance of the Petronet-RasGas contract negotiations.

However, buyers should not get too greedy in all of this, because after 2020 the pendulum will likely start to shift again in favor of producers. As natural gas prices bottom out, likely in 2016 and a few years after that, even plummeting to around $4, investment in new LNG projects will cease, which will halt new production. With new production tapering and demand increasing over the long term, markets will do what they do best, which is swing yet again in the other direction.

Anadarko says it will make Mozambique LNG decision in 2016

(Financial Times; London; Dec. 7) – Anadarko is planning to make a final decision next year on how it will develop vast gas discoveries the company has found off the east coast of Mozambique. There have been concerns that the collapse in oil prices could cause big delays in the commercialization of Mozambique's liquefied natural gas projects, but Al Walker, Anadarko's chief executive, said the company was on track to start producing LNG by late 2020.

Pressing ahead with Anadarko's gas development in the Rovuma Basin in the Indian Ocean hinges on the company taking a final investment decision, which had been expected this year. That decision is now due for the second half of 2016, Walker said, following important agreements with the Mozambique government governing gas for local demand and a joint development agreement with Eni, the Italian oil company that has also made large gas discoveries in the Rovuma Basin.

Anadarko has discovered more than 75 trillion cubic feet of gas in the basin, while Eni has found about 85 tcf. Mozambique would be Anadarko's first foray into LNG. The first phase of the project — expected to cost at least $15 billion — would include building two LNG trains, with output of 12 million metric tons per year. Anadarko is hopeful it can benefit from delays with other energy projects and industry-wide cutbacks in capital spending, allowing it to negotiate better prices with contractors and service providers.

Qatari LNG exec predicts strong demand growth

(Asian Oil and Gas; Dec. 6) - Despite recent turbulence, the global market for liquefied natural gas remains strong and continuous demand growth is expected for years to come, said Khalid Sultan R. Al Kuwari, chief marketing and shipping officer of Qatar's RasGas. Speaking at an LNG conference in Italy, Al Kuwari said a demand growth rate of approximately 5 percent per year from 2015-2025 is anticipated. "During this period, LNG demand is expected to outpace the overall growth in natural gas demand."

Challenges to the traditional LNG pricing mechanism in Asia, "combined with the recent drop in crude prices and the resurgence of nuclear and coal for power generation has changed the familiar landscape for LNG in Asia and brought into question economics for some new and some planned LNG projects," he said. "However, new customers and new markets for LNG are also increasing at an ever faster pace. LNG is still a business requiring significant capital investments in production, liquefaction and transportation."

In October, the CEO of RasGas, Hamad Mubarak Al Muhannadi, told delegates at Gastech in Singapore that the decline in LNG prices and introduction of new suppliers will require a collaborative effort from LNG suppliers and buyers to adopt a sustainable market. "However, if LNG suppliers fail to develop resources required to meet forecasted longer-term demand growth at the right time and place, there will be a supply and demand imbalance with longer-term implications for LNG prices."

Europe's move away from coal-fired power plants will benefit gas

(Bloomberg; Dec. 8) - Lawmakers from Germany to the U.K. want to legislate coal out of existence. And as their profit margins slump, power producers too are giving the fuel the cold shoulder in favor of cleaner natural gas. The switch to the less polluting fuel is so far most prominent in the U.K. market. After natural gas prices dropped 26 percent this year, the fuel last month was more profitable than coal in power generation for the first time since 2011, according to data compiled by Bloomberg.

Gas has also started to displace older coal plants in Germany at times of peak power demand, according to Pira Energy Group, a consultant to the industry. As European nations phase out coal, utilities are so bullish on the future of gas that they are bringing back mothballed plants. "This is a turning point in European power," said Bruno Brunetti, a senior director of electricity at Pira, who has tracked Europe's energy markets for 20 years. "This is a structural recovery in gas-plant profitability, not just a random uptick."

The tide against coal extends beyond power-plant economics. Norway's $900 billion wealth fund and insurer Allianz SE this year joined investors snubbing the fuel. While it is currently used to generate 41 percent of the world's electricity, almost twice that of gas, coal's share will drop to 30 percent by 2040, according to the International Energy Agency in Paris. Britain will phase out its dirtiest coal-fired power plants by 2025 and plans to spur new gas and nuclear stations as replacements.

Low prices help gas overtake coal for U.S. power generation

(EnergyWire; Dec. 9) - Gas-fired power generation is increasingly overtaking coal-fired generation as sustained low prices give the cleaner fuel an edge, federal statistics show. April of this year marked the first month ever in which natural gas outpaced coal in U.S. power generation. But the trend has gathered momentum as July, August and September brought the same dynamic, according to the U.S. Energy Information Administration's latest short-term energy outlook.

EIA expects that the two fuels will vie for top billing in the nation's electric generation portfolio over the near term, with coal contributing 34 percent to 32 percent for gas on a yearly basis in 2015 and 2016. EIA points to low gas prices as the main driver behind the shift, which saw a 4 percent lead for natural gas over coal in electric generation for September. The agency is predicting the Henry Hub natural gas spot price to average $2.47 per million Btu this winter, down from $3.35 last year.

The combination of lower gas prices and predictions of a generally warmer winter this year than last are expected to bring significant savings for U.S. households that heat with natural gas — an average 13 percent reduction in heating expenses. Nationally, natural gas storage is at an all-time high; inventories touched a record 4.01 trillion cubic feet last month before starting their seasonal decline, EIA data show. Taken together, the trends point to a near term of continued low natural gas prices.

U.S gas production to set new record in 2015

(Reuters; Dec. 8) - The U.S. Energy Information Administration on Dec. 8 said domestic natural gas production in 2015 was expected to reach 79.58 billion cubic feet per day, topping 2014's record 74.89 bcf. It would be the fifth consecutive record year for U.S. gas production. For 2016, the EIA forecasts more records with production rising to 81.05 bcf and consumption to 76.66 bcf. The surplus mostly will go out as pipeline gas to Mexico and LNG from the first Gulf Coast export plant, starting up in January.

The EIA said power sector consumption drove demand growth in 2015, while industrial consumption was flat in 2015 but is expected to increase by 3.9 percent in 2016 with new industrial projects, particularly fertilizer and chemical plants. The agency expects production will increase due to rising drilling efficiency despite low gas prices and fewer drill rigs at work. Most of the production growth is expected to come from the Marcellus Shale as drillers reduce the backlog of uncompleted wells and new pipelines go online.

China’s cut in natural gas prices could deepen losses for importers

(Radio Free Asia; Dec. 7) - China has slashed natural gas prices to boost consumption of the cleaner-burning fuel, but the move may come as a shock to producers that have been struggling with low demand growth this year and importers that lose money on gas sales. China's top planning agency cut wholesale gas prices for non-residential users Nov. 20 by an average of 28 percent, reducing the charge by $3 per 1,000 cubic feet. The agency has been under pressure for months to revise its policies as high natural gas prices have discouraged demand and efforts to curb reliance on high-polluting coal.

Lower prices could speed fuel switching by power producers and industry, easing smog and carbon emissions. The government's goal is to boost the gas share of China's primary energy mix to 10 percent by 2020 from 5.7 percent last year. The target is seen as critical to meeting China's pledges to fight climate change. But the huge price cut, coming after a smaller adjustment in April, will leave some segments of the gas market reeling, raising doubts about whether the policy can be sustained.

"Domestic producers and importers of gas will certainly be hit with losses of billions of U.S. dollars," said Philip Andrews-Speed, principal fellow at the National University of Singapore's Energy Studies Institute. PetroChina, an arm of state-owned China National Petroleum Corp., lost $1.68 billion on gas imports in the first half of this year. The lower prices could have far-reaching consequences, particularly if consumption does not respond to the price cut, leaving producers with high development costs and low sales.

Canadian city council votes for repeal of LNG terminal tax break

(CBC News; Dec. 8) - The City of Saint John will ask the New Brunswick provincial government to repeal a special property tax deal for the Canaport LNG terminal. Council member Shirley McAlary started the debate by introducing a motion to ask the provincial government to repeal the controversial tax deal for Canaport — an LNG import terminal, which its owners are thinking of expanding to export liquefied natural gas. "We've got to start where we have to start," McAlary said. "And that's with the province."

The deal, approved by the provincial legislature in 2005, chopped municipal property taxes on the terminal by more than 90 percent. It fixed the rate at $500,000 per year until 2030. In 2005, the provincial government created special legislation to facilitate the tax deal after an endorsement by the city council. Norm McFarlane, the former Saint John mayor, told council members he had been assured construction of the import terminal could not proceed without the 2005 arrangement.

A report to city council Dec. 7 by John Nugent, the city solicitor, said the terms of the lease arrangement were likely not known at the time of the previous council vote. Already under budget pressure to cut services and lay off staff, city councillors lined up Dec. 7 to support McAlary's motion. "There's a time for giving and there's a time when you can't give any more," said council member John MacKenzie. "And we're at a time when where we need every nickel we can get." The motion passed on a 7-2 vote.

B.C. First Nations have not settled sharing of gas pipeline payments

(Terrace Standard; Terrace, BC; Dec. 9) - Seventeen First Nations spread over more than 600 miles across northern B.C. are struggling to divide as much as $30 million in annual payments from the provincial government should three pipelines carrying natural gas from the northeast to proposed liquefied natural gas export plants on the West Coast ever be built. None of the LNG project developers have committed to start construction, though the province remains hopeful.

An original deadline of June 30 has been extended to Dec. 31 as the First Nations consider a series of detailed options over how much money each should receive. Each of the pipelines — Coastal GasLink to Kitimat for the planned LNG Canada plant, Prince Rupert Gas Transmission to the Prince Rupert area for the Pacific NorthWest LNG plant and the Westcoast Connector to another planned LNG plant at Prince Rupert — would provide the affected First Nations with $10 million a year in provincial payments.

The province originally said it would step in and make decisions on how to divide the money should the First Nations not reach agreements by June 30, but is now giving them more time to come up with their own formula. Allocation issues are the number of miles each line would stretch through each First Nation's territory, while some question whether they want pipelines constructed at all and some neighboring First Nations have overlapping territorial claims. And some question if any of the pipelines will ever be built.

Renewed U.S. Gulf oil production adding to oversupply

(Wall Street Journal; Dec. 6) - The standoff between major global energy producers that has created an oil glut is set to continue next year in full force, as much because of the U.S. as of OPEC. American shale drillers have only trimmed their pumping a little, and rising oil flows from the Gulf of Mexico are propping up U.S. production. The overall output of U.S. crude is down less than 3 percent, to 9.3 million barrels a day, from the peak in April. Some analysts even see potential for U.S. output to rise next year.

The situation has surprised even seasoned oil traders. "It was anticipated that U.S. shale producers, the source of the explosive growth in supply in recent years, would be the first to fold," Andrew Hall, chief executive of the commodities hedge fund Astenbeck Capital Management, wrote in a Dec. 1 letter to investors. But the companies slashed costs and developed better techniques to produce more crude and natural gas per well.

Meanwhile, production is growing in the Gulf, where companies spent billions of dollars developing megaprojects that are now starting to produce oil. Just five years after the worst offshore spill in U.S. history shut down drilling in the Gulf, companies are on track to pump about 10 percent more oil than they did in 2014. In September, they produced almost 1.7 million barrels a day. Since most of the money was spent before crude prices cratered, and since pipelines and other infrastructure are already in place, it makes economic sense for the companies to go ahead with the projects despite the glut.

Further spending cuts possible as oil falls below $40

(Wall Street Journal; Dec. 8) - Brent, the global oil benchmark, fell below $40 a barrel for the first time in six years Dec. 8, dipping below what traders say is a key level for the marker used by the world's oil producers to price their crude. The development is further proof that the oil-price malaise could continue far longer than first forecast by analysts and observers. The psychological impact of sub-$40 Brent could prompt speculators, traders and money managers to start scaling back on investments in the oil sector.

The U.S. West Texas Intermediate benchmark fell below $40 back in August, but many analysts were predicting Brent to stay above $45 as recently as last week. Brent's dip below $40 for the first time since February 2009 is another marker in the steep decline in crude that followed the Organization of the Petroleum Exporting Countries' decision Dec. 4 to keep supply unchanged. The decision sent prices into heavy falls, with shares of energy companies tumbling and analysts scrambling to recalculate their predictions.

Brent is a blend of crudes from several North Sea fields and is the primary reference point for pricing of about two-thirds of the world's oil. The benchmark typically trades above WTI, which has a lower density. Though producers have scrambled to lessen the impact of falling prices on their businesses, few have prepared for a prolonged period in which oil remains below $40. Such an eventuality will mean the extension of deep spending cuts, project delays and cost-reduction programs.

U.S. shale oil production down 600,000 barrels a day from peak

(Reuters; Dec. 7) - U.S. shale oil production is expected to fall by more than 600,000 barrels per day in January from the March peak, according to a U.S. government forecast Dec. 7, on the back of a global glut that's slashed oil prices to a near seven-year low. Total U.S. output — shale, tight oil and conventional oil — is set to decline by just over 115,000 barrels in January compared with December, according to the U.S. Energy Information Administration.

Bakken Shale oil production from North Dakota is set to fall 27,000 barrels, while production from the Eagle Ford is expected to fall by 77,000 barrels a day. Low oil and gas prices have pushed companies to cut back on drilling and production.

About 5% of oil wells in North Dakota are up for sale

(EnergyWire; Dec. 10) – North Dakota's oil production slide paused in October, but state regulators said production could fall more if the price continues to slide, and some companies have begun selling their oil wells in a last-ditch effort to fund their operations. Companies pumped 1.17 million barrels a day in October — about 7,000 a day more than in September but still about 5 percent below the all-time production number set in December 2014, according to data released by the state Dec. 9.

The number of drilling rigs in the state has fallen to 65 this month, down 70 percent from its high in 2012, and another 10 rigs could be shut down if prices continue to drop, Department of Mineral Resources Director Lynn Helms said during a conference call with reporters. "We're looking at a lot of belt-tightening, and we're looking at it continuing through the entire first half of 2016," Helms said.

Nationwide, oil prices have fallen almost two-thirds since the summer of 2014 to about $38 a barrel this week. In North Dakota, oil traded for $27 a barrel, largely because of the state's distance from refining centers. About 710 oil wells are up for sale, Helms said, citing records of bond transfers. That's about 5 percent of the wells in the state. About 300 are being sold by Occidental Petroleum, which announced in October it will sell its Bakken Shale operations to concentrate on other fields, Helms said.