Oil and Gas News Briefs
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Low natural gas prices cut into Pennsylvania land owners' royalties

(Pittsburgh Post-Gazette; Sept. 9) - Stubbornly low natural gas prices are leaving Pennsylvania property owners with diminished royalty checks even as record amounts of gas are pulled from the commonwealth's shale formations. The deep price slump also has left shareholders angry and pushed companies to slow new development. Royalty owners — those who have leases with drilling companies and share a stake in the gas sold from their property — have few options but to hope for prices to rebound.

Lower gas prices, driven in large part by a supply that has outpaced demand, has put a dent in state and local budgets as well. The commonwealth is one of the largest royalty owners in Pennsylvania with more than 260,000 acres of state forests, parks, and waterways leased for oil and gas drilling. Statewide, from all public and private lands, drillers produced an average 18 billion cubic feet of gas per day — second in the nation to Texas. In 2014, gas from state land sold at an average of $4 per 1,000 cubic feet. In 2018, sales averaged $2.80. Now the sale price is even lower--around $2.25.

Pennsylvania's annual drilling impact fee — which funds environmental, infrastructure, and local government projects — is also influenced by the price of gas, and the slump threatens to drag down those payments, too. If the average gas price on the New York Mercantile Exchange drops below $3 per million Btu for 2019 — as it is on track to do — drillers will pay $5,000 less per horizontal well. That would reduce total impact fees to $201 million for the year — nearly $47 million less than state and local governments would receive if average prices remained above $3, according to state projections.

Platts' report says U.S. natural gas prices could stay low for 5 years

(Houston Chronicle; Sept. 9) - U.S. natural gas prices are expected to stay low over the next five years, as the possibility of recession looms over the global economy, research firm S&P Global Platts Analytics reported Sept. 9. U.S. benchmark prices at Henry Hub are projected to average $2.66 per million Btu through 2024, a decline of 8 percent from last quarter's forecast. Natural gas prices averaged $3.17 per million Btu last year.

"This is in response to softening global market conditions, increased associated gas production and muted domestic demand-side gains," the report read. Were the global economy to go into recession next year, demand from U.S. power and industrial sectors would likely decline a combined 2 billion cubic feet a day — 2 percent of total U.S.

demand — further knocking down prices, Platts said. "A global economic recession remains a distinct possibility next year," the report said.

Freeport LNG secures financing for expansion

(LNG Global; Sept. 9) - Freeport LNG and Australia-based private-equity firm Westbourne Capital on Sept. 9 announced agreements for Westbourne and its co-investors to provide up to $1.025 billion in a mezzanine loan for Freeport's expansion project. The loan, combined with bank financing, gives Freeport 100 percent of the capital required to add a fourth liquefaction train at its Texas export terminal, the company said. Freeport shipped the initial cargo from Train 1 earlier this month and is finishing construction on Trains 2 and 3.

Freeport has approval from the Federal Energy Regulatory Commission for the expansion, and has a contract with KBR for engineering, procurement, construction, commissioning, and start-up of Train 4. All four trains at Freeport are rated for 5 million tonnes annual production. The construction cost for the first three trains at the terminal on Quintana Island in Freeport, Texas, has been estimated at $15 billion. A mezzanine loan — generally at higher interest rates — is secondary to senior lenders and allows the holders to convert their debt to equity if payments are late or in default.

Founded in 2002 and headquartered in Houston, Freeport LNG built a liquefied natural gas import terminal on Quintana Island in 2008 and later decided to add liquefaction and export to the unused import operation.

Freeport looks to investment decision on LNG expansion

(S&P Global Platts; Sept. 9) - Freeport LNG expects to make a final investment decision in the next several months on a proposed fourth liquefaction train at its Texas export facility, after securing a loan of approximately $1 billion from an Australian independent investment manager, the operator said Sept. 9. The loan from Westbourne Capital and its investors, together with other bank financing being contemplated, would cover the full cost of building Train 4, at 5 million tonnes annual capacity, Freeport said.

The company has yet to announce any firm long-term offtake deals tied to the expansion. A year ago it announced a preliminary deal, or heads of agreement, with Japan's Sumitomo for 2.2 million tonnes per year of capacity from Train 4, though Freeport LNG has yet to say whether that deal has been finalized. In an emailed statement, CEO Michael Smith said Freeport LNG has "an eye toward FID in the next several months." He said Westbourne has been an investor in Freeport's past activities.

The first liquefaction unit is online at Freeport, with two more under construction. The carrier LNG Jurojin departed on Sept. 3 with the facility's first cargo. A second tanker was moored at Freeport on Sept. 9 for loading. Train 4 already has Federal Energy Regulatory Commission approval and authorizations from the Department of Energy, as well as a fixed-price engineering, procurement and construction contract with KBR to build the liquefaction unit. Freeport has previously targeted start-up of Train 4 for 2023.

Australian company wants to reduce stake in LNG project in Canada

(The Financial Post; Canada; Sept. 10) - Australian oil and gas giant Woodside Energy is looking to sell part of its stake in the proposed Kitimat LNG project on Canada's West Coast in a move that analysts are cheering as a sign the mega-project is progressing. Woodside CEO Peter Coleman told Reuters at a conference in Abu Dhabi on Sept. 10 that the company is interested in selling part of its interest in the Chevron-led Kitimat LNG project in northern British Columbia because it would not be the operator.

Woodside holds a 50 percent stake in the project alongside Chevron, the would-be operator, and Woodside is looking to reduce its exposure by adding another partner to the venture. Analysts believe state-owned oil giants from Kuwait and Malaysia would be the most likely buyers if Woodside reduces its stake. One possible buyer for Woodside's stake could be the Kuwait Foreign Petroleum Exploration Co., according to Raymond James analyst Jeremy McCrea, who notes that Chevron and the Kuwaiti company are already partners in an upstream gas project in the Duvernay shale formation in B.C.

Canadian energy executives and gas analysts said the move by Woodside to find a partner is encouraging as it likely indicates the companies are getting closer to allocating capital to the project and determining their exposure. Unlike other LNG proponents, Woodside does not own gas-producing assets in Canada. The companies have not announced a timeline for a final investment decision on the project, planned for as much as 18 million tonnes annual capacity. The development would be about 12 miles from the Shell-led, C$40 billion LNG Canada project that is under construction.

Papua New Guinea's Oil Search sees geographic diversity in Alaska

(Reuters; Sept. 9) - With a giant natural gas expansion effort in the tropical highlands of remote Papua New Guinea bogged down by politics, the country's biggest company, Oil Search, is turning for growth to the other side of the world in Alaska. Australia-listed but based in Port Moresby, the company has shaped the oil and gas industry in Papua New Guinea over the past 90 years, helping drive development in the impoverished nation.

But the scale of its projects there has left it dependent on decisions by giant international partners, while government demands for a bigger stake in resource projects may delay a planned two-pronged $13 billion liquefied natural gas expansion. The confusion has opened a window for Oil Search to push ahead with a promising field in Alaska's North Slope that it bought into in 2018 and where it is the project operator. Despite a steep learning curve, it plans to start producing as early as 2022.

"It's a perfect foil in terms of product diversity and geographic diversity. It's an excellent asset in the sense that we can control it a lot better," Oil Search Managing Director Peter Botten told Reuters in an interview. "You'd think they're likely to get there quicker on Alaska than they do on PNG at this stage," said Andy Forster, a portfolio manager at Argo Investments which more than doubled its holdings in Oil Search in the past year.

In Alaska, Oil Search paid $850 million for a 51 percent stake in the Pikka prospect with the belief it holds 500 million barrels of recoverable oil. With Repsol, it aims to produce 30,000 barrels a day by 2022 to start earning cash, then ramp up to 120,000 barrels in 2024. It's also hoping to prove up reserves closer to 750 million barrels by early 2020, find more oil near its Nanushuk field, and sell part of its holdings to help fund Pikka.

Nigeria LNG signs letter of intent to build seventh train

(Reuters; Sept. 11) - Nigeria LNG said Sept. 11 it had moved closer to an investment decision on the long-awaited Train 7 project to expand its liquefied natural gas plant on Bonny Island. The company said in a statement it had signed a letter of intent for the engineering, procurement and construction of Train 7, one of the key milestones toward a final investment decision (FID). The letter was signed with a consortium consisting of Italy's Saipem, Japan's Chiyoda, and South Korea's Daewoo.

Nigeria LNG said it had also submitted its evaluation of commercial bids for Train 7 to the government, another step in project approval. "The project will form part of the investment of over $10 billion including the upstream scope of the LNG value chain," the statement said. The company said construction after FID will last four to five years. The project, which would increase Nigeria's LNG production by 35 percent to 30 million tonnes per year, has been delayed for several years. Nigeria started exports in 1999.

Algeria brings on new gas production to offset older fields

(S&P Global Platts; Sep. 9) - The U.K.'s Neptune Energy and its partner Algeria's state-owned Sonatrach have finally begun exporting gas from Algeria's delayed Touat gas project, the companies said Sept. 8. The much-delayed Touat field complex — one of several new gas projects that have come online in Algeria to offset falling output at older fields — has been beset by operational delays and missed deadlines.

The project is now flowing gas into Algeria's grid with full output projected at 450 million cubic feet per day. Over the past few years, several major new gas projects have started up in Algeria including the Timimoun tight-gas field and the Reggane Nord gas field complex, while the Tinrhert field is due online by the end of 2019.

Touat production will represent about 6 percent of Algeria's gas exports and will be in production for over 20 years. In 2018, Algeria exported 586 billion cubic feet of gas by pipeline to Spain, 575 bcf by pipeline to Italy, 510 bcf as liquefied natural gas, according to data from S&P Global Platts Analytics. Total exports in 2018 were down 4 percent from 2017. Algeria’s domestic consumption is now above 1.4 trillion cubic feet a year, up from 950 bcf in 2010, according to the Gas Exporting Countries Forum.

Dutch will stop production at Europe’s largest gas field by 2022

(Reuters; Sept. 10) - The Netherlands will halt production at Groningen, Europe’s largest onshore gas field, by 2022, eight years earlier than initially planned, the Dutch government said Sept. 10. Groningen produced 1.9 trillion cubic feet of gas in 2013 before tremors blamed on drilling damaged buildings and prompted a series of caps on output and protests by residents and campaigners. An unusually strong earthquake in January 2018 prompted the government last year to promise to end production by 2030.

But Economy Minister Eric Wiebes last month signaled the end could come a lot sooner, citing greater capacity to convert high-calorific imported gas to the low-calorific standard of Groningen gas and a switch by large industrial users to other sources of energy. These measures will enable production to fall to zero by mid-2022, assuming average weather conditions, Wiebes said Sept. 10.

After that, the field will be kept operational until 2026 at the latest, he said, to meet high demand for gas on exceptionally cold winter days. Discovered in 1959, the Groningen field — run by a Shell and ExxonMobil joint venture — was long one of Europe’s main gas suppliers. Output hit a peak of 3.1 tcf in 1976. A 3.4 magnitude earthquake in May increased the pressure to end production faster than planned, as the Dutch regulator called for an immediate 40 percent reduction to limit seismic risks.

That reduction in output will cost the Dutch state around 400 million euros ($441 million) over the next 12 months, Wiebes said, adding that he expects to reach an agreement with Shell and Exxon in the first half of 2020 on the cost of ending output at Groningen.

Qatar takes 100% of capacity to 2044 at Belgian LNG import terminal

(Gulf Times; Qatar; Sept. 8) – Qatar Petroleum, parent company of RasGas, has booked the full receiving capacity of Belgium’s Zeebrugge LNG import terminal for the next 25 years. QP and its affiliates and the Belgian gas transport company Fluxys Belgium recently signed the long-term deal that will reach the terminal's full capacity of 7.2 billion cubic feet of gas per day as other existing receiving contracts expire.

The Zeebrugge terminal was commissioned in 1987 and later expanded. It serves as a central point for the gas distribution network in Northwest Europe, with several gas pipelines providing the terminal with takeaway capacity. The terminal is operated by Fluxys LNG. Europe is a key market for Qatar's liquefied natural gas exports, Minister of State for Energy Affairs Saad bin Sherida al-Kaabi, also the president of Qatar Petroleum, said at the signing ceremony in Brussels.

Deal to send Israeli gas to Egypt runs into challenges

(Wall Street Journal; Sept. 7) - A landmark 2018 natural gas deal between Israel and Egypt faces legal challenges and concerns about security threats from Islamic State, casting uncertainty over a pact hailed as a sign of deepening ties between the two countries. Egypt was supposed to begin importing Israeli gas in March as a part of the $15 billion deal, providing an outlet for Israel's burgeoning gas production. The accord was also meant to mark a thaw in decades of cool relations between the two neighbors.

But the gas never started flowing as complications arose over the pipeline connecting the two countries and other aspects of the deal. Israeli officials blame bureaucratic setbacks at home for the delay and say the project could start by January. Egyptian officials didn't respond to requests for comment. The delays have hit Egypt's plans to become an export hub for vast gas reserves discovered in the eastern Mediterranean. Cairo aims to liquefy Israeli and other gas and re-export it to Europe or sell it domestically. There are two underused gas liquefaction and export terminals in Egypt.

The gas is supposed to flow over the existing pipeline between Israel and Egypt across part of the Sinai Peninsula, where Islamic State's Egyptian branch has reasserted itself in recent months. The group claims to have killed more than 300 people in Egypt during the first half of 2019. "If they can't protect themselves and their own infrastructure, it will be a struggle for them to protect this gas line infrastructure," said Zack Gold, an expert on the Sinai insurgency at CNA, a security consulting firm.

New gas line will help boost price earned by Permian producers

(U.S. Energy Information Administration; Sept. 6) - The Gulf Coast Express Pipeline, at 2 billion cubic feet per day, will provide much-needed additional natural gas pipeline capacity for the Permian region of Western Texas and Southeast New Mexico. Coinciding with start-up of the new pipeline, gas spot prices at the Waha hub in western

Texas, located near Permian Basin production, settled at $1.55 per million Btu on Aug. 15, the highest since March.

Limited takeaway capacity from the region has kept prices very low, or even negative, in recent months. During the first eight months of 2019 (through Aug. 19), the Waha spot price averaged just 65 cents per million Btu. Deliveries into the new pipeline began on Aug. 8, with full start-up expected in September. The line will deliver gas to a connection point near the Texas Gulf Coast.

As the Gulf Coast Express Pipeline enters service, several other new lines also are planned to move Permian output to the Gulf Coast for export as liquefied natural gas or as feedstock for petrochemical plants. Of seven additional pipelines, two have reached a final investment decision and are scheduled to enter service in 2020 and 2021.

New Permian gas pipelines could help reduce flaring

(Forbes columnist; Sept. 9) - Start-up this month of the Gulf Coast Express gas pipeline and several more gas and gas liquids pipelines during 2020 is expected to help reduce flaring in the Permian Basin. Rystad Energy reported in June that flaring in the Permian hit a record in the first quarter, burning as much as 661 million cubic feet day from wells unconnected to a gas line or that would cost producers more to move the gas to market than it was worth. The Gulf Coast line will be able to move 2 billion cubic feet per day.

However, Rystad notes that a disproportionate share of the flaring is coming from the Midland North part of the Permian, almost 100 miles away from the Gulf Coast Express origination point near Pecos, Texas. The Gulf Coast Express system has a lateral up to the Midland area, so it should have some positive impact, but how much is uncertain.

Another big question is: When all the additional gas starts to come onto the market from the new pipelines, with a total capacity of about 6 bcf per day, how will all that new supply affect the price of natural gas? With supply already substantially out-stripping demand in the U.S., the hope is that most of this added gas will be able to find a home in international markets as liquefied natural gas exports or pipeline exports to Mexico.

Natural gas-powered buses gain popularity with cheap, cleaner fuel

(Houston Chronicle; Sept. 6) - Houston, San Antonio, Las Vegas and the bustling border town of Ciudad Juarez, Mexico, have one thing in common — buses that run on compressed natural gas, liquefied natural gas or propane. Quieter and cleaner-burning than their diesel-powered peers, natural gas-powered buses are also touted as money savers. With record production in the Permian Basin and other shale plays, natural gas prices are fallen to around $2.45 per million Btu — their lowest in nearly three years.

There's so much gas and not enough pipelines to move it that much of it is burned off at drilling sites in a practice known as flaring. Supporters of CNG, LNG and propane believe that flared gas can be sold and put to more useful purposes. CNG is made from compressing natural gas. LNG is made from super-cooling the gas until it becomes a liquid. Propane is a byproduct of gas processing and petroleum refining. In most U.S. markets, a gallon of all the fuels can be sold for less than a gallon of diesel or gasoline.

San Antonio's transit agency boasts the largest CNG fueling station in North America. The agency has some electric buses but is in the middle of switching the rest of its nearly 450 buses to CNG, a move expected to save millions of dollars in fuel per year and improve air quality. Public transit agencies in Fort Worth and El Paso exclusively use CNG-powered buses. Visitors to Las Vegas go to and from the airport or up and down the Strip in CNG-powered buses. All Las Vegas garbage trucks also run on CNG.

Florida leads nation in moving to gas-fired power generation

(U.S. Energy Information Administration; Sept. 9) - Florida added nearly 16 gigawatts of utility-scale natural gas-fired electric generation between 2008 and 2018, about one-quarter of all U.S. natural gas power capacity during those 10 years and the most of any state. During the same period, the share of gas-fired electric generation capacity in Florida's energy mix grew from 47 percent to 72 percent.

The U.S. Energy Information Administration expects gas-fired generation capacity to continue to grow, displacing more emissions-intensive and less cost-competitive generation fuel sources such as coal and petroleum liquids. About 40 percent of Florida's gas generation capacity was built between 2008 and 2018. Florida was the third-largest state for electricity retail sales during 2017, and growth in its electricity sector has been among the fastest in the United States since 2007.

Additions to gas pipeline capacity have kept pace with new gas-fired electricity generation in Florida, the EIA reported. Gas pipeline delivery capacity to Florida increased from 4.1 billion cubic feet per day in 2008 to 6.2 bcf per day in 2018.

Cheniere asks Texas Supreme Court to settle property tax dispute

(Corpus Christi Caller Times; Texas; Sept. 9) - Cheniere Energy is asking the Texas Supreme Court to intervene in what it claims is an ongoing double-taxation issue between Nueces and San Patricio counties. The issue is similar to one in which the Supreme Court ruled in favor of Occidental Chemical in October 2018. Occidental had argued that it was being double taxed by Nueces and San Patricio counties for the same commercial piers jutting into Corpus Christi Bay.

The Supreme Court ruled in October that Occidental should pay property taxes only to San Patricio. The justices agreed with a lower court ruling that "past and future natural and artificial modifications to the shoreline of San Patricio County shall form a part of San Patricio County." The Supreme Court called the situation "blatant double taxation." Cheniere Energy is arguing the same point. The piers at its Corpus Christi LNG facility are in water in Nueces County, which assesses tax on the property, but attached to land in San Patricio County, which also sends the company a tax bill.

In 2014, before it began building Corpus Christi LNG facility in San Patricio County, Cheniere began receiving notices of appraised value from both counties. The notices were for the same property, mostly submerged land at the time. "Although the double taxation was improper, the values were, at the time, not material, so … (Cheniere) remitted payment to both counties without protest," the company told the Supreme Court. By 2017 the assessments on the submerged land and improvements led to tax bills of more than $100,000 from each county, Cheniere said. By 2018 the company received a notice for a combined tax liability of more than $3 million.

Exxon in talks to sell Gulf of Mexico assets to Repsol

(Reuters; Sept. 9) - Spanish oil giant Repsol is in advanced talks to acquire some deepwater assets in the U.S. Gulf of Mexico from ExxonMobil for about $1 billion, three people familiar with the matter said Sept. 9. The deal would be a boon to Exxon's plans to accelerate asset sales, as it seeks to raise cash to return to shareholders and focus on promising acreage in offshore areas such as Guyana and Brazil, and onshore in the Permian Basin of Texas and New Mexico.

There is no certainty a deal will be agreed, the sources said. The transaction would require approval from partners in the assets, who may have preferential rights to buy them, said two of the sources.   The sources asked not to be identified because the matter is confidential. Representatives for Exxon and Repsol declined to comment. Exxon began the process to jettison Gulf of Mexico assets last year with advice from JPMorgan Chase & Co., Reuters reported last October.

According to a document seen by Reuters dated Fall/Winter 2018, Exxon was marketing nine assets. These included its 50 percent stake in the large Julia oil field, which it operates, as well a 9.4 percent piece of the Heidelberg field and 23 percent of the Lucius oil and gas field, both of which are now operated by Occidental Petroleum. The exact number of assets that Exxon would sell to Repsol could not be learned.

Expectations of sustained low oil prices lead to spending cutbacks

(Reuters; Sept. 6) - Oil producers and their suppliers are cutting budgets, staffs, and production goals amid a growing consensus of forecasts that oil and gas prices will stay low for several years. The U.S. has 904 working rigs, down 14 percent from a year ago, and even that is probably too many, estimated Harold Hamm, chief executive of shale producer Continental Resources, which has reduced the number of rigs at work.

Bankruptcy filings by U.S. energy producers through mid-August have nearly matched the total for all of 2018. A stock index of oil and gas producers hit an all-time low in August, a sign investors are expecting more trouble ahead. Investment bank Cowen & Co. estimated last month that total spending this year will fall 11 percent over last year, based on proposed budgets. The slowdown in drilling also is spurring cost-cutting in oil field services, including staff cuts and restructurings.

U.S. oil prices are likely to remain below $55 a barrel for the next three years, said Scott Sheffield, CEO of Pioneer Natural Resources, one of the largest oil producers in the Permian Basin. Even as small and mid-sized firms dial back, the majors — ExxonMobil, Chevron, and Shell — continue to pour billions of dollars into years-long shale drilling plans. They have argued their integrated well-to-refinery networks allow them to control costs enough to withstand a sustained period of low prices. Exxon has estimated it can earn a double-digit return in the Permian Basin even if oil falls to $35 a barrel.