# Oil and Gas News Briefs
# Compiled by Larry Persily
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## Opposition takes heavy toll on new gas pipeline projects

(Houston Chronicle; July 20) - A decade ago, when the shale boom was in its infancy, developers lined up to build long-distance gas pipelines to supply distant markets with low-cost energy to replace aging, dirty coal and oil-burning power plants.  But after years of legal fights with environmental groups trying to eradicate carbon-emitting fossil fuels, pipeline companies are backing off large-scale projects.  The decision earlier this month to cancel the 600-mile Atlantic Coast Pipeline is just the beginning, experts say.

“There’s so much uncertainty on the project timeline and the cost that you are unlikely to see another major natural gas pipeline built (that crosses state lines),” said Sam Andrus, executive director of North American gas at the consulting firm IHS Markit. “These environmental groups have made it their explicit goal to delay these projects and raise the costs.  And they’re getting better at it as time goes on.”

A lack of pipelines would limit markets for gas producers in states such as Texas, which produces more gas than any state.  A study by the American Petroleum Institute predicts that demand from oil and gas producers would support construction of more than 17,000 miles of pipelines in the next five years.  But between legal fights with environmentalists and state and local politicians moving to block pipelines to address climate change, it looks unlikely that anywhere close to that amount will be built.

That is likely to have a chilling effect on lenders and investors, which developers rely on for financing, said Stephen Brown, an energy consultant.  “You’re going to have to pick your targets a little more carefully, and investment capital is going to get scarce.”

## High-profile pipelines lose in court, but a lot of others succeed

(Politico; July 20) - Environmentalists are celebrating a string of wins that put the brakes on three major pipelines last week, but oil and gas industry insiders and even some green groups say those setbacks have barely made a dent in the sector's growing web of pipes.  Despite the high-profile courtroom losses for the Keystone XL and Dakota Access oil lines and cancellation of the Atlantic Coast gas line, the oil and gas industry has succeeded in putting tens of thousands of miles in the ground in recent years.

And while green groups appear to be winning the public relations battle for some of the biggest projects, they may be losing the smaller skirmishes that are locking in fossil fuel infrastructure for years to come, say industry analysts.  “One thing for sure is there is a lot going on in the pipeline world outside of the public attention on shiny objects like Keystone XL, Dakota Access or Atlantic Coast," said John Stoody, vice president of government and public relations at trade group Association of Oil Pipe Lines, pointing to government records showing about 10,000 miles of oil pipelines were built since 2015.

That leaves the Mountain Valley Pipeline, which developers plan to carry gas from West Virginia to Virginia, as the last major multistate gas or oil pipeline still moving ahead — and opponents are vowing to fight it as hard as they did the others. Trump administration officials and some in the gas and oil industry blame green groups for the recent high-profile setbacks. But others are instead chalking up the headwinds to low oil and gas prices and the weak financial condition of many energy companies, as well as inept permitting by the Army Corps of Engineers and deficient environmental reviews.

## Chevron takeover of Noble Energy could signal start of consolidation

(The New York Times; July 20) - Many experts consider Chevron's $5 billion takeover of Noble Energy as the beginning of a sweeping consolidation in the U.S. oil industry. The pandemic has caused a sharp decline in oil demand, putting intense pressure on oil companies with large debts. This includes Noble, which is based in Houston and has operations in Colorado, Texas, the eastern Mediterranean, and West Africa. But it has also created an opportunity for oil giants to gobble up smaller fish and extend their acreage in places like the Permian Basin, which straddles Texas and New Mexico.

Chevron already has a large presence in the basin and easy access to large pipeline networks, which should help it put Noble's assets to good use. "In a downturn like this, the strong get stronger and the weaker players try to survive as best they can, and some will be bought," said Duane Dickson, Deloitte's vice chairman and U.S. oil, gas, and chemicals leader. "There will be some bankruptcies and mergers and acquisitions like you saw today and I would expect that will continue and potentially pick up speed."

Like others, Noble has struggled to make a profit with oil at around $40 a barrel. Even before the pandemic, the shale boom produced so much oil that a growing number of wells were unprofitable. Over 20 North American producers have filed for bankruptcy this year. Industry executives said Chevron's move follows a pattern in which bigger, financially stable companies acquire smaller, less stable outfits during downturns. "You should see even more of these types of acquisitions happening as the crude price stays in this lower range," said Kirk Edwards, president of Latigo Petroleum in Texas.

## Chevron paid $5 per barrel for Noble's proven reserves

(Reuters; July 21) - Chevron's surprise $5 billion all-stock deal for oil producer Noble Energy should spell the end of this year's deal drought, setting a price benchmark that will trigger more buys, according to mergers and acquisition bankers, lawyers and analysts. The COVID-19 pandemic destroyed fuel demand and left dozens of energy companies without the prospect of drilling their way out of debt. They may now be more willing to entertain deals, with the Chevron offer as a standard.

"Sometimes you need the one significant deal to reset the comps and manage price expectations," said Andrew Dittmar, a mergers and acquisition analyst at researcher Enverus. Chevron agreed to pay $5 a barrel for Noble's proved reserves, a price that could reset expectations for sellers weighing deals, analysts said. The bid also values Noble's unproved reserves, those yet to be shown to be economically recoverable, at half of what Chevron offered for similar reserves at Anadarko last year, Chevron said.

Other oil companies that have hinted at interest in cheap reserves and have the wherewithal to buy include ConocoPhillips, ExxonMobil, and Total. "I do not think this marks the end of large deals for the oil and gas sector," said Jon Clark, an oil and gas transactions executive at consultancy EY. "We see this strategic trend continuing."

## Union reports cracks in propane unit at Chevron's Gorgon LNG

(Australian Associated Press; July 22) - Australia's largest liquefied natural gas project, the Gorgon development off the West Australian coast, is at risk of being shut down for months after workers raised serious safety concerns. The LNG plant on Barrow Island, about 37 miles off the Pilbara coast, is operated by Chevron, and the US$54 billion venture is under threat of a temporary shutdown after reports by a workers union of "massive" cracks in pressurized propane kettles on one of three liquefaction trains.

Cracks up to three feet long and more than one inch deep were found on between eight to 11 kettles on Train 2, the Australian Manufacturing Workers' Union said July 22. The units carry pressurized propane. Train 2 has been in a scheduled maintenance period since May, which had been due to end July 11, according to a Chevron activity notice. The union is concerned there could be similar cracks in the other two trains, which remain in production. It wants Chevron to shut down Gorgon for an immediate safety inspection.

In a statement, Chevron said investigations were ongoing and regulatory authorities had been informed. "Maintenance turnarounds are a regular part of safely operating natural gas plants and provide an opportunity to undertake various inspections, repairs and equipment change-outs to ensure safe and reliable operations," a spokesman said. The three-train plant, at 15.6 million tonnes annual capacity, started operations in 2016.

## U.S. could be short pressure pumpers when oil industry recovers

(Bloomberg Businessweek; July 21) - Twenty years ago, before the U.S. oil industry became a global energy power that strikes fear into Saudi Arabia, brothers Dan and Farris Wilks started Frac Tech Services in tiny Cisco, Texas. The company provided equipment for hydraulic fracturing. Frac Tech grew into one of the most successful pressure pumpers as the U.S. experienced a boom first in shale gas and then in shale oil. The Wilks brothers became billionaires when they sold Frac Tech in 2011, just as shale oil was transforming the U.S. into one of the world's biggest producers of crude.

The U.S. oil renaissance has ridden heavily on the backs of little-known pressure pumpers that figured out how to extract oil from the stubborn shale of Colorado, New Mexico, North Dakota, Texas, and Wyoming. Today the Wilks' former company, now publicly traded and named FTS International, is fighting to stay alive. Since March, FTS has slashed executive pay, idled most of its pumping gear, and laid off two-thirds of its employees. It has more debt than cash. Its stock fell to about 30 cents a share in May.

Other pumpers are suffering, too, with thousands of workers laid off. Research firm IHS Markit recently pondered whether conditions could "create a scenario in which a wave of bankruptcies in service companies leaves North American shale without enough pumpers to do the work." As oil historian Daniel Yergin has observed, companies go bankrupt, rocks don't. Assuming prices recover, producers will begin to turn wells back on — a process that's never been tried at this large a scale — and maybe drill new ones. Whether they start paying pumpers better remains to be seen.

## Dakota oil line shutdown could send 200,000 barrels a day to rail

(Bismarck Tribune; ND; July 20) - While lawyers fight over a judge's order to temporarily shut down the Dakota Access Pipeline, the oil industry is grappling with uncertainty as it ponders how to keep shipping Bakken crude to market. The questions on everyone's mind: Will the pipeline actually be forced to halt operations and when? "It's a very chicken-and-egg situation," said Elliot Apland, a managing member of MarbleRock Advisors, which handles supply and logistics for the rail and energy industries.

Many observers anticipate a shutdown could result in a resurgence of trains carrying Bakken crude, a prospect that has rail safety advocates and farmers concerned. Whether more oil trains hit the tracks depends on the outcome of the latest legal maneuvering over the pipeline. At the moment, the order to shut down the line is on an administrative hold as the case moves to a panel of federal appeals court judges.

The shutdown order came July 6 from U.S. District Judge James Boasberg, who for four years has overseen a lawsuit launched by the Standing Rock Sioux Tribe. Tribal members worry a spill could devastate their water supply. Boasberg ordered developer

Energy Transfer to idle the line for the duration of a lengthy environmental review expected to last at least 13 months, and for the company to drain the line by Aug. 5.

The line has been operating for three years and can transport up to 570,000 barrels per day of oil from North Dakota to Illinois. Several experts anticipate that a shutdown would eventually prompt oil companies to ship an additional 200,000 barrels a day of Bakken crude by rail, the equivalent of about three more oil trains leaving the region each day.

## Higher costs make North Dakota vulnerable to oil cutbacks

(Forbes contributor; July 21) - North Dakota produces more crude oil per capita than other any large oil-producing state in the country, including nearly 10 times more than Texas. Regardless, the state’s production has fallen further during the pandemic-driven oil rout than that of any other major oil producer. Between January and May, North Dakota’s oil production plummeted 40%, according to data released last week by the state, outpacing the 10% overall decline in U.S. production over the same period.

The size of the drop in the state's production — from 1.4 million barrels per day at the start of the year to 860,000 in May — could exceed the oil production decline in Texas in both percentage terms and outright, even though Texas produces four times more oil. Fueled by the prolific Bakken shale basin in the state’s northwest corner, North Dakota has ranked second only to Texas in production since 2012. But it may have sunk back into third place behind New Mexico beginning in May.

Experts have warned before that North Dakota is vulnerable to an oil bust. Located far from the refining hub along the coast of the Gulf of Mexico, producers here rely on costly networks of pipelines, rail and trucks to transport their output. Oil companies plumbing Bakken shale require a break-even oil price of around $45 per barrel to cover their operating expenses, more than the roughly $40 average per barrel that producers in the Permian Basin in Texas and New Mexico need, analysts estimate.

## State reverses local permit approval for Oregon LNG project

(Herald and News; Klamath Falls, OR; July 22) - The Jordan Cove Energy Project hit another roadblock July 17 after an Oregon state agency reversed local approval for part of the construction plan. The city of North Bend had approved a local land-use permit last year for Jordan Cove to operate a dredging project in the Coos Bay estuary to deepen the water for access to the LNG export terminal. The company wants to construct a temporary pipe to transport the dredged material to two disposal sites.

The pipe and other dredging infrastructure would run through several zones of the estuary. Each zone's designation involves a specific set of management practices that development projects must follow. The Oregon Shores Conservation Coalition and a Coos Bay organization, Citizens for Renewables, appealed the city council decision to the Oregon Land Use Board of Appeals, raising objections to the city's approval on the grounds that the $10 billion project would not satisfy those management goals.

The state board agreed with several of the points, two of which were significant enough to reverse the decision and require Jordan Cove to reapply for the permits. Calgary-based Pembina Pipeline has been working several years to obtain permits, customers and financing for the LNG plant at Coos Bay and a 229-mile cross-state gas pipeline to feed the plant. Pembina this spring obtained Federal Energy Regulatory Commission approval for the project but has lost several key permits at the state level.

## Stock sale will keep U.S. LNG hopeful alive until next year

(Reuters; July 22) – Houston-based Tellurian is considering changes to its proposed Driftwood LNG export project in Louisiana that could significantly reduce the overall Phase 1 costs, the company said July 22. The company also disclosed plans to issue 35 million shares at $1 each, a 37% discount to the July 21 closing price, sending its stock plunging 27%. The stock sale comes four months after Tellurian laid off over 40% of its employees, reshuffled executives and cut expenses in a bid to save its project.

Tellurian announced July 22 it had reached a deal with institutional investors to buy the $35 million of stock as LNG developers worldwide have delayed numerous projects as the COVID-19 pandemic has sapped overall fuel demand and hammered gas prices. Tellurian has said the Driftwood project, designed to produce 27.6 million tonnes per year of LNG, is expected to cost $27.5 billion, including feeder pipelines. About $15.4 billion of the estimate is for a contract with Bechtel to build the liquefaction plant.

Scotiabank analysts estimated the cash infusion could provide the company "sufficient runway until July 2021" based on a $6 million monthly cash burn. The offering "provides some needed capital to extend discussions with potential customers", the analysts said. Tellurian holds federal authorization for construction and exports but lacks enough off-take contracts and financing to reach a final investment decision.

## Qatari LNG could benefit if competitors delay or cancel plans

(Gulf Times; Qatar; July 19) - The long-term outlook for Qatar's second natural gas boom does not fundamentally change regardless of the eventual economic impact of COVID-19 on the global energy market, a new report says. According to consultants at

PwC, the current crisis may even work to Qatar's advantage as potential competitors, particularly in the U.S., delay or cancel major LNG export projects.

"The most important economic development in many years was the surprise announcement by Qatar Petroleum in November that new appraisals had extended estimates of both the geographic scope and volume of the North Field," PwC said in the Qatar Economy Watch. The field, which was previously thought to be only offshore, has been found to extend at least 10 miles onshore and the reserves had been increased to 1,760 trillion cubic feet of gas and 70 billion barrels of condensates.

That's a doubling of gas reserves and more than a tripling in oil, compared with Qatar's most recently published estimates. With the larger reserves, Qatar upsized its plans for the North Field expansion by 50%, to six new gas liquefaction trains, which will add 49 million tonnes per year of capacity, about a 64% increase over current capacity of 77 million tonnes a year. The additional capacity is expected to start coming online in 2025.

## Insurance company wants out of Canadian oil line coverage

(Reuters; July 22) - Insurer Zurich has decided not to renew coverage for the Canadian government's Trans Mountain oil pipeline, said a spokeswoman for the project, which is opposed by environmental campaigners and some indigenous groups. Financial services companies are under pressure from environmental campaigners to cease doing business with the fossil fuel industry.

A planned expansion of the pipeline, which ships oil to a British Columbia terminal from Canada's main oil-producing province of Alberta, also has drawn opposition from some First Nations leaders anxious about the environmental risk to their communities. A spokesman for Zurich said the insurer did not comment on customer relationships. Trans Mountain said it has the insurance it needs for its existing operations and the expansion project, which is under construction.

The pipeline's annual liability insurance contract, dated August 2019, had shown Zurich as the lead insurer. The insurance, which provides $508 million of coverage, runs to August 2020, the filing showed. Other insurers are part of the coverage, including Lloyd's of London syndicates, Chubb, Liberty Mutual, and Munich Re unit Temple. The Canadian government bought the pipeline and expansion project in 2018 when the owner, Kinder Morgan, wanted out, frustrated at permitting and litigation delays.

## [Southeast Asia nations focused more on pandemic than clean energy]

(S&P Global Platts; July 21) - Japan's vocal renunciation of support for coal-fired power generation within the country and overseas addresses much of the criticism recently leveled at its industrial conglomerates for backing fossil fuels, but its repercussions are complicated and could take years to play out. That's because the government decision is more structural than individual corporate policy and is likely to percolate through channels like state financing rather than curbs on technology exports.

The policy's impact on alternative fuels like liquefied natural gas and renewables in the Asia-Pacific also needs to be viewed against the backdrop of coal-backing by China, the status of the energy mix in the end-user nations of Southeast Asia and South Asia, and its timing in the midst of the pandemic. The coronavirus has shifted most governments into disaster-management mode and for the time being few countries will be bothered by whether Japanese conglomerates can finance their next coal-fired power plant.

"In Southeast Asia, the trouble is life is complicated by the virus; governments are short of money and they've got other things to worry about," said Philip Andrews-Speed, of the Energy Studies Institute of the National University of Singapore. "The virus has made decision-making by governments on clean energy more difficult because they've got less money in the short term and maybe in the longer term too," he said. "The minister of clean energy isn't necessarily the most important person in the Cabinet."

## [Medicine Hat wants to sell off aging wells to avoid liabilities]

(Calgary Herald; July 20) - The City of Medicine Hat, Alberta, is in talks to sell more of its municipally owned oil and gas assets, as the province's historic natural gas boomtown tries to manage aging wells with ballooning environmental clean-up costs and well remediation liabilities. "The City of Medicine Hat has reached out to the province to arrange a meeting to discuss their abandonment and reclamation obligations," said a spokeswoman for Alberta Energy Minister Sonya Savage.

Medicine Hat is the only municipality in Alberta to own, drill and produce gas from its own reserves. In recent years, however, the city's financial reports show environmental remediation liabilities relating to its gas assets have more than doubled. In 2016, the city sold off some assets to reduce its liabilities for plugging and reclaiming old wells. Financial analysts and legal experts say the city is facing the same types of fiscal pressures as embattled oil and gas operators in southern Alberta's mature gas fields.

Many private-sector operators have struggled as gas prices collapsed in Alberta, turning many of their wells uneconomic. The total of inactive and orphan wells has ballooned in the province, leading to the federal and provincial governments allocating money to remediate tens of thousands of wells. Medicine Hat has not pushed any of its wells to the province's Orphan Well Fund. The city has owned its own production arm for more

100 years.  It was producing about 6,500 barrels of oil equivalent per day when it said last fall it will abandon more than 2,000 of its 2,600 wells in the next three years.

## Gas flaring totaled 5.3 tcf worldwide in 2019

(Reuters; July 21) - Gas flaring worldwide increased to 5.3 trillion cubic feet in 2019, the highest level in more than a decade, primarily due to increases in the United States, Venezuela, and Russia, the World Bank said July 21.  In particular, flaring — the burning of gas associated with oil production — in fragile or conflict-affected countries climbed from 2018 to 2019, in Syria by 35% and in Venezuela by 16%, the World Bank report said.  Flaring was up 23% in the United Sates and 9% in Russia.

The top four gas-flaring countries by volume — Russia, Iraq, the United States, and Iran — continue to account for 45% of all global flaring for three years running (2017-2019), the World Bank said.  However, flaring overall fell by 10% in the first quarter of 2020, with declines across most of the top 30 gas-flaring countries, it added, likely due to pandemic-induced cutbacks in oil and gas production.  Producers will flare gas when they cannot economically move it to market due to lack of processing and/or pipeline capacity or when prices are too low to cover transportation costs.

## Europe accelerates its exit from coal-fired power plants

(Reuters; July 22) - Europe’s long goodbye to coal is speeding up in a transition smoothed by the rise of wind and solar power and energy policy that has priced the fossil fuel out of many markets, according to data released on July 22.  Centuries after powering Europe’s industrial revolution, coal cannot compete with less polluting fuels to generate electricity, prompting governments and companies to close mines and plants.

Renewable sources of power have taken over for the first time in 2020, generating 40% of European Union electricity, while fossil fuels generated 34%, independent think-tank Ember said in a half-yearly report.  In Spain, coal generation fell 58% in the first six months of the year, even before half its remaining plants closed in June as they no longer complied with EU emissions rules.

In addition, the COVID-19 outbreak has depressed power demand, further reducing coal consumption, the analysts said.  In Portugal, coal generation fell 95% in the first half of 2020, Ember said.  The Netherlands, Austria, and France all saw reductions of more than 50%.  Sweden and Austria closed their last coal plants in March.  In Germany coal generation fell 39%, taking it for the first time below Poland, which now generates as much electricity from coal as the EU’s remaining 25 countries put together.

## [Canada’s oil patch starts to bring back shut-in production]

(CBC News Canada; July 20) - After the brutal price crash in March and April, the mood in Canada’s oil patch is noticeably improved as prices stabilize around US$40 per barrel. Still, that price means different things to different companies with some beginning to turn on the taps to produce more oil, some barely able to break even, and others still struggling mightily. At Calgary-based Bonterra Energy, the price is high enough to turn a modest profit, but still too low to start drilling for oil again.

For now, Bonterra executives are holding tight. They don't want to be caught committing big dollars and have oil prices collapse again, especially after they fell into negative territory in April. "We're sitting on it and watching it almost on a day-by-day basis," said George Fink, the company's chief executive. "We're all set up to go back to drilling, but right now we're still just a little bit being shy."

Heavy oil producers in Alberta, which include many oil sands players, are receiving a price in the low US$30s per barrel, high enough for several to begin restoring some production. Cenovus Energy had cut output by 60,000 barrels per day and already has brought back 50% of it. Husky Energy has revived half of the 80,000 barrels per day it had taken offline. "This could be a little bit of a tough slog for at least the next six to 12 months," said Martin Pelletier, a Calgary-based analyst with Wellington-Altus Private Counsel, an investment and wealth management firm. "Beyond that is anyone's guess."

## [Pickup in U.S. gasoline demand helps Canadian oil producers]

(The Wall Street Journal; July 21) - Aggressive cuts by Canadian oil producers in the spring are starting to pay off in the summer. After coronavirus-related shutdowns stalled business, U.S. oil refiners have started making more gasoline for drivers who are returning to the road. That has increased demand for Canadian oil, which is the largest source of crude for Midwest refineries. Though the recovery is still nascent and remains fragile, it is an improvement from March.

In March, amid a global supply glut and pandemic-related slowdowns, oil prices plunged and companies decided to shut down wells because they had few places to sell their oil profitably. Canada’s oil industry, the world’s fourth-largest producer, was hard hit because it is almost entirely dependent on the U.S. as an export market. As the U.S. economy froze, many Canadian producers curtailed output, cut spending, stopped share buybacks or shaved dividends. Now they’re sounding a more optimistic tone.

“They’re coming out of the other side of this in decent shape,” said Matt Murphy, an analyst with Tudor Pickering Holt in Calgary. “I think in hindsight it will have been a fairly smart decision to cut production.” Canadian producers in May cut average production by 1.3 million barrels a day from February levels, according to the U.S. Energy Information Administration. It was the lowest since mid-2016.

## Saudis will burn more oil to power air conditioners this summer

(Bloomberg; July 22) - As the Middle East enters the hottest days of summer, Saudi Arabia is set to burn potentially record amounts of crude oil to run its power plants and keep its citizens comfortably air-conditioned. Electricity consumption always soars around July and August, when temperatures in the kingdom can rise above 122 degrees Fahrenheit. That compels the government to use crude or fuel oil in addition to the much cleaner natural gas that normally fires the plants.

This year the urge to drain oil is even stronger because of higher demand with the coronavirus pandemic forcing many Saudis to cancel their summer holidays abroad. Another difference is that record cuts to Saudi Arabia's oil production since April — part of a push by OPEC members to prop up prices in the face of the virus — have reduced its supplies of natural gas, most of which come from the same wells as crude.

The extra oil going toward power generation may limit the impact of OPEC's plan to taper oil output restrictions from next month. The kingdom, the cartel's biggest producer, pumped 7.5 million barrels a day in June, the fewest since 2002, according to data compiled by Bloomberg. Of those, it exported 5.7 million barrels daily, keeping the rest for domestic refineries or power. Each August, Saudi Arabia uses 726,000 barrels of crude daily for power generation, according to average numbers over the past decade.

## Putin orders Russia to consider hedging against future oil-price drops

(Bloomberg; July 22) - Russian President Vladimir Putin ordered his government to consider hedging Russia's massive oil and gas export revenues to protect the country from drops in prices, Interfax reported July 22. Mexico has used a similar system for the past two decades via put options that the government buys from a small group of oil companies and investment banks. The country banks only some of the gains when oil rallies but enjoys the security of a minimum floor when prices dip below the hedge price.

Russia's finances took a big hit this year when prices collapsed amid global coronavirus lockdowns and a price war with Saudi Arabia. The budget deficit will mostly be filled by extra borrowing to avoid eroding currency reserves that may be needed in future oil price slumps. Under the proposal to be considered in Russia, the government would use money from its wealth fund to buy put options, which would generate profits if oil prices fell. Officials are to produce a more detailed plan by the end of this month.

Russia has considered hedging in the past but never adopted the plan. Mexico's oil hedge cost the government about $1 billion annually in recent years, but it meant that the country earned profits in every oil-price downturn the past 20 years. The Mexican government estimates it may make roughly $6 billion in 2020. Despite that success, no other major oil-producing country has followed suit with a similarly large hedge.  The risk is that if prices rise, a country could lose out on much of the extra revenue.