MIDSTREAM Business

The Export Challenge

The midstream responds to surging sales abroad.

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The Export Challenge

On the cover: The Cyprus-flagged *Grand Aniva* and her LNG tanker sisters are making more calls at U.S. ports as the nation's exports of natural gas grow. *Source: Shutterstock/VladSV*

Editor's Note

The Sea-Change

By Paul Hart, Midstream Editor-At-Large

"Full fathom five thy father lies;
Of his bones are coral made;
Those are pearls that were his eyes:
Nothing of him that doth fade,
But doth suffer a sea-change
Into something rich and strange."

—Ariel in *The Tempest*, by William Shakespeare

I fell into the energy business midway between the two shortage-plagued oil shocks of the 1970s and I relish several high points during my career: visits to the North Sea and Prudhoe Bay; a tour of Henry Hub; time at Kenai, Alaska, within the nation's first LNG liquefaction plant; and an itinerary around Singapore's sprawling refining/petrochemical industry.

Alas, I endured some low points. One of the lowest was an energy investor conference in early 2005 in Boston. The keynote speaker was a world-famous economist, who expounded on the obvious truth of Hubbert's Peak. His extensive PowerPoint presentation backed up his argument that the days of oil and gas were numbered. The world was on the downhill side of the famed geophysicist's curve—and the nation in the worst shape of them all was the U.S.

Energy demand continued to surge while our gray-haired domestic oil fields were drying up. There was no more gas to be found either. We were a nation of growing energy imports as far as he could see into some sort of future lit by solar panels, windmills or, perhaps, improved nuclear reactors.

Applause at the end was sparse. The several hundred of us in the big hotel ballroom had deer-in-the-headlights expressions: We were telegraphers making buggy whips. We had no future.

Nearly 14 years later and things have not quite turned out that way. Thanks to the late George Mitchell and his crew, and later a rare positive gesture to the oil business by President Obama, we live in a world that's the opposite of that gloomy Boston forecast.

As surely as Shakespeare's characters, instead we have come "into something rich and strange."

The U.S. is today the world's largest crude oil producer, roughly one in every six barrels. It has more natural gas than it knows what to do with. This nation has emerged as a major exporter of both, as well as a major supplier of petroleum products.

We confront a major and unexpected challenge in the midstream. This nation has excellent midstream infrastructure, but much of it is in the wrong place. Much of the repurposing that could be done has been done. Now, we face the need for greenfield projects costing well into the billions of dollars.

Perhaps the greatest challenge of all is how to handle exports. Crude that once moved from, say, the Permian Basin to inland refiners must have access to Gulf Coast docks. And what of those docks? Most were built to unload tankers, not load them.

Perhaps the greatest challenge of all is how to handle exports. Crude that once moved from, say, the Permian Basin to inland refiners must have access to Gulf Coast docks. And what of those docks? Most were built to unload tankers, not load them.

It's a daunting proposition for the midstream and worthy of the big word Shakespeare created in his play: sea-change. An appropriate term, given that seaborne commerce is key to making it all work.

We pause here as 2018 ends and a new year begins to look at what has happened and what needs to occur. All of this seems bewildering and overpowering at times, but it's a nice problem to have. It certainly beats work as a telegrapher making buggy whips.

My best wishes to all of you for a wonderful holiday season. ■

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Take It Away, Midstream!

The sector is heeding producer pleas with a flurry of projects but bottlenecks will persist until late 2019.

By Joseph Markman

Two words have defined the North American oil and gas challenge in the last two years: takeaway constraints.

The midstream has responded with two words of its own: on it.

Construction activity—and plans for more—have gravitated toward the Permian Basin and Gulf Coast but the LNG Canada announcement—a $31 billion project—grabbed the most attention as the fourth quarter began.

Permian Basin

Production capacity in the Permian Basin will outpace takeaway capacity by 46,000 barrels per day (Mbbl/d) in fourth-quarter 2018, Stratas Advisors projected in September. Things will get worse before they get better. No major pipeline projects are expected to come online until fourth-quarter 2019, which will expand the gap between production and takeaway to an average of 371 Mbbl/d from first-quarter 2019 through the end of next year's third quarter.

Stratas expects producers to either ease up on adding rigs or turn to trucks and rail to move the crude to key markets.

"A third possibility could be the use of additional pumping and drag reducing agents (DRAs) on pipeline," the analysts wrote. "The use of DRAs reduces turbulence on the pipeline, thus increasing its capacity by as much as 100 Mbbl/d."

That sentiment is echoed by Marshall McCrea, chief commercial officer of Energy Transfer Partners LP, which plans to expand capacity of its Permian Express 3 Pipeline by 100 Mbbl/d. "Everywhere we possibly can use DRA across the country, we are," he said.

What works for Plains All American Pipeline LP is finishing projects ahead of schedule. Executives said in the third quarter that the Sunrise expansion project is expected to go into partial service in the fourth quarter and its Cactus II line will begin partial service from Wink, Texas, to McCamey, Texas, in third-quarter 2019.

The Sunrise extension will add about 500 Mbbl/d of capacity from Midland, Texas, to Colorado City and Wichita Falls, Texas, and provide connections to the Cushing, Okla., crude trading hub. The Cactus II Pipeline will provide 670 Mbbl/d of capacity from the Permian to Corpus Christi, Texas, when it runs at full service in April 2020.

The "sooner the better" mantra was shared by EPIC Midstream Holdings LP. In early October, the company announced its subsidiary had cleared the approval process to begin crude oil service on a portion of the EPIC NGL Pipeline when that project is completed in third-quarter 2019. Customers clamoring for crude transport out of the Permian convinced EPIC to utilize the third and final phase of its NGL line from Crane, Texas, to Corpus Christi for crude service while the EPIC Crude Oil Pipeline and EPIC NGL fractionator are being built. The NGL pipe will revert to NGL service when EPIC's crude line is completed by January 2020.

The portion of the NGL line to be placed into crude service will originate in Crane with an additional injection point in Wink and will have multiple terminal and refinery connections in Corpus Christi and Ingleside, Texas. It will have a capacity of 400 Mbbl/d for its interim crude service.

Also attending to NGL demand is ONEOK Inc., which plans to invest about $295 million in an expansion project for its 2,600-mile West Texas LPG pipeline system.

NGL expansion

The expansion involves construction of four new pump stations, two pump station upgrades and pipeline looping that will increase mainline capacity by 80 Mbbl/d. Additional infrastructure will connect the line with ONEOK's 530-mile Arbuckle II NGL pipeline project that moves Oklahoma supply to Mont Belvieu.

The proposed Whistler Pipeline Project, a joint venture with four partners, will transport 2 billion cubic feet per day (Bcf/d) of gas from the Midland and Delaware basins to Gulf Coast markets when it enters service in fourth-quarter 2020. Partners include Targa Resources Corp., NextEra Energy Pipeline Holdings LLC, WhiteWater Midstream LLC and MPLX LP.

It's an ambitious project incorporating about 450 miles of 42-inch pipeline from the Permian's Waha, Texas, gas hub to NextEra's Agua Dulce, Texas, market hub, with about 170 miles of 30-inch pipe continuing from Agua Dulce and terminating in Wharton County, Texas. Whistler would have access to

See TAKE IT AWAY *continued on page 70*

The Liberian-flagged very large crude carrier *FPMC C Melody* loads oil at Enterprise Products Partners' Texas City, Texas, marine terminal. The vessel was one of the first supertankers to visit a U.S. dock. Limited channel clearance at U.S. ports means the biggest tankers have to wait to be topped off at sea after weighing anchor. *All photos courtesy Enterprise Products Partners LP*

A Different World

Seismic shifts lie ahead as the U.S. continues to grow as a global energy export power.

By Frank Nieto

Thinking back to 2008, the world seemed like a very different place. Donald Trump was a businessman and host of a popular reality show, ExxonMobil Corp. was the largest company in the world based on market capital, and "American Idol" on Fox was the most popular show on television.

Today, Trump is, of course, the U.S. president, ExxonMobil has fallen behind tech heavyweights like Apple, and "American Idol" just returned to network television on ABC after being cancelled several years ago by Fox.

On the other hand, the world isn't that different: The New England Patriots lost the Super Bowl in 2008 and 2018, the most popular movies at the box office in both 2008 and 2018 featured superheroes, and the iPhone has been the most popular gadget every year in this 10-year span.

The renaissance

More importantly to the oil and gas industry in general and the midstream in particular, 2008 marked the beginning of the U.S. energy renaissance. Though West Texas Intermediate crude prices hit a record $147 per barrel (bbl) that summer, the U.S. ended the year as the largest producer of natural gas.

Shortly thereafter, producers began using similar unconventional production techniques and technologies to replicate the success they were having with shale gas to unlock crude and liquids plays.

Clearly this strategy has paid off, with the U.S. producing more crude oil than any other country for the past seven years—while breaking production records on a regular basis for the past four. This amount of production resulted in Congress lifting the domestic ban on crude exports at the end of 2015.

The U.S. is now on track to become the largest exporter of crude in 2019.

Currently, the U.S. exports about 2 million barrels per day (MMbbl/d) of crude and condensate combined, but these levels are just the start of where production and export levels are going. At its peak, the U.S. will be a Top-Five exporter competing with OPEC member nations, Russia and Canada for market share.

"Our forecast has U.S. crude exports peaking at 4.5 MMbbl/d (3.6 MMbbl/d of only crude, and 900,000 bbl/d of condensate) in 2032 with a slow decline from there. Exports will also peak at this time and have similarly slow decline," John Coleman, senior analyst, North American crude markets, Wood Mackenzie, told *Midstream Business*.

Mega-growth

Exports are set to more than double over the next 15 years, but the most significant gains will be in the next five years or so as the U.S. goes into "mega-growth mode," as one industry observer called it. A combination of high-quality inventory and a long runway of drilling locations are leading to this growth. The dominant barrel produced in the U.S. will be very light sweet crude, and according to Coleman, a great deal of this production will need to be placed into export markets.

"The light and ultra-light variety of crude that's being produced in the U.S. is increasingly becoming saturated in a very complex domestic refining system. So as production continues to grow, it's not a direct 1:1 relationship that every barrel produced has to be exported, but the majority of new production going forward is going to need to be exported," Coleman said.

"We don't have enough crude in the next 10 years to completely make Middle Eastern crude irrelevant for the whole world, but we have enough for the U.S. to not to care about it anymore," Dan Lippe, managing partner, Petral Consulting, told *Midstream Business*.

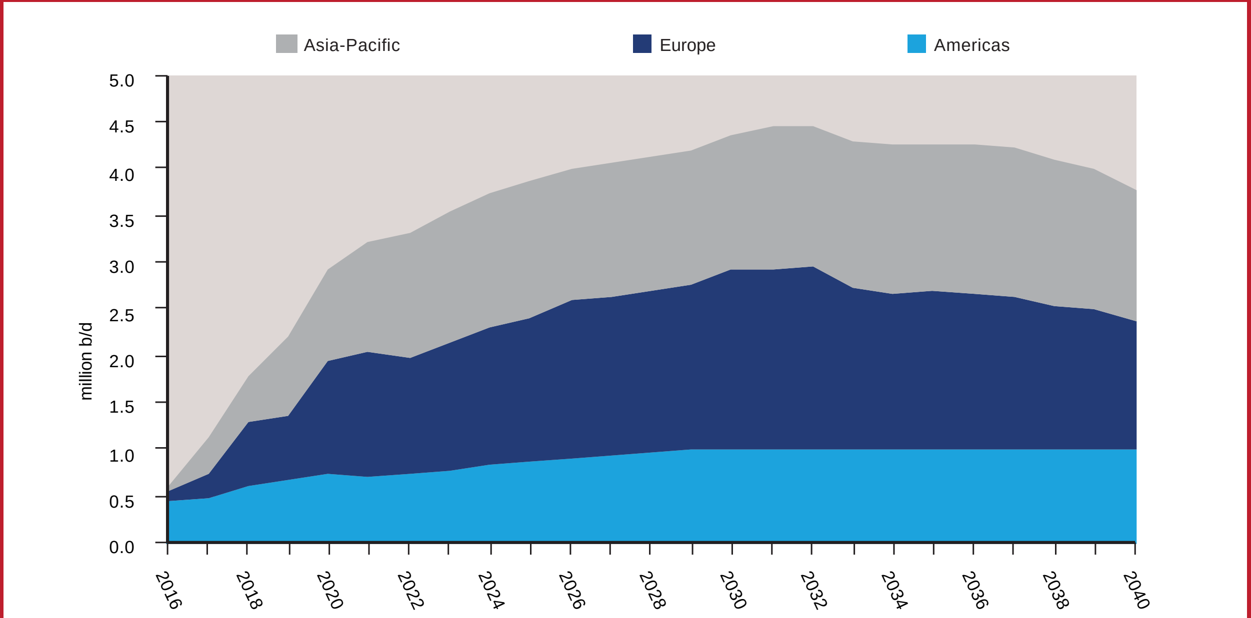
According to Petral Consulting, since the majority of U.S. production needs to be exported, it can take a great deal of the global crude market share from Middle Eastern producers within the next decade.

"We've already doubled capacity and we have the capability to double again. It's the inevitability of the situation that astounds me," Lippe said.

Key destinations

Some destinations that look favorable for U.S. crude, for different reasons,

Destinations of U.S. Light Crude and Condensate Exports



Source: Wood Mackenzie

"I realize this perspective is not the consensus view, but anyone who denies the threat of all-electric vehicles out of hand is whistling past the cemetery. The majority of global oil demand is from transportation fuel. We're talking the beginning of the end of oil as the dominant transportation fuel."

– **Dan Lippe**, *managing partner, Petral Consulting*

are the European and Asian markets, according to Wood Mackenzie. Ideally, both markets will see significant uptake in volumes in the coming years as the U.S. competes with existing light crudes in both markets. Refining capacity in China is ideally suited to take a great deal of these volumes, and the Chinese market makes up about 20% to 25% of total U.S. exports.

Asian markets will also be important in absorbing U.S. condensate exports due to the large number of condensate splitters and crude-to-chemicals facilities in the region.

"There's going to be a tightening in global condensate availability into the 2020s with the U.S. being one of the largest suppliers of condensate, as well as one of the few with growing volumes," Coleman said.

However, any long-term trade tariffs on U.S. crude will not have a material impact, he said. "Should any tariff scenario play out where the Chinese market gets shut off to U.S. crude exporters, we don't think it puts the overall export story at risk, but it can reshuffle and reshape global crude trade flows based on that."

In such a scenario, Wood Mackenzie anticipates that U.S. volumes flowing to China will be redirected to the next-best available market with China pulling volumes from other markets. Ultimately, the export story will remain intact, albeit in a slightly less efficient way.

"Today those barrels are largely flowing to where producers can get the highest prices possible. If that market is shut off, crude flows are going to have to redirect and producers will have to sell into the next-best available market. This means slightly worse price realizations going forward. Now what is the magnitude of that? It's probably not going to be hugely significant, but it would result in a wider discount in U.S. crude relative to international benchmarks," Coleman said.

Besides Asian markets, European markets are expected to be focal points for U.S. crude exports, specifically in northwestern Europe and the Mediterranean. The refineries in these regions are less complex than in other parts of the world, which makes U.S. light sweet crude attractive since it has less sulfur and requires less processing than other, heavier types of crude.

This isn't to say that OPEC's importance will cease in the coming decades. It may be on the decline as far as importance to domestic markets, but OPEC will remain the marginal swing producer for the foreseeable future, according to Wood Mackenzie.

"Going forward, we expect OPEC to retain this role by having the capacity available to add supply when needed and make informed market decisions if supply needs to be removed. The U.S. is going to be much more economically driven, so for the U.S. to remove supply or greatly ramp up supply, there would need to be a price response first to incentivize producers. OPEC makes decisions largely on its views of where the market is going," Coleman said.

Midstream infrastructure

Midstream operators have been key in helping U.S. crude producers make such remarkable gains in production and export market share in the past decade and will continue to play an important going forward.

"Mont Belvieu, Texas, will continue to be the focal point of midstream activity because of its proximity to West Texas and access to waterways. All of the pipeline interconnections point to this region with the largest liquids storage capacity in the country. Mont Belvieu will be the price-setting mechanism for NGL and petrochemical products," Lippe said.

Despite a consistent buildout and expansion of pipelines for much of this century, such is the size of U.S. production that more pipeline capacity is still

Changing Cycles

Market cycles for U.S. crude, liquids and gas will change in the coming years as the country becomes more involved in global markets.

The U.S. oil and gas industry is about to get even bigger in the next decade with the country continuing to grow in its role as a global energy superpower. Domestic producers have been exporting natural gas, NGL, crude oil and petrochemicals—and these volumes will keep growing.

What impact will this have on prices?

At first glance, it would be easy to predict they'll go up as the U.S. gains market share in various regions. However, other countries are also increasing their export volumes, demand dynamics are changing and there are important geopolitical considerations that will impact short-term and long-term pricing.

"We'll start to see shorter cycles in the crude oil market. So instead of 15-year cycles, we're going to see three- to four-year cycles," Dan Lippe, managing partner, Petral Consulting, told *Midstream Business.*

That may sound like the market will become less orderly, but that's far from the case. In many ways, the global crude market is about to become both more competitive and more efficient. And the biggest driver of this change will be production out of West Texas, according to Lippe.

"West Texas is the only place that matters. Production in the region has increased so much that all of the pipelines are full. Fortunately, we're building new pipeline like mad and should have at least an additional 1 million barrels per day (MMbbl/d) of additional crude pipeline capacity by the middle of next year. That will start to alleviate the current constraints, which have slowed down the growth rate in West Texas crude production," he said.

What's most impressive about West Texas is that even with this slowdown, the annualized growth rate in the second quarter of 2018 was still an impressive 1.5 MMbbl/d per year.

The Iran sanctions

While West Texas is the most important crude play in the world right now, the most important story in the short term is the restoration of economic sanctions against Iran in the coming months. These sanctions will effectively force countries that are currently buying Iranian crude to choose between doing business with Iran or the U.S.

"Very few buyers are going to choose Iran over the U.S. because we have the ability to make up the loss of Iranian crude [from the world market] by ourselves," Lippe said.

While the U.S. will likely gain market share from Iran's departure, so will other countries like Russia, Iraq and Saudi Arabia. Domestic crude demand will not absorb U.S. production growth, which means most of these new volumes will have to be exported. This could have a negative impact on prices in the next 18 months with global production outpacing demand. The prices at which U.S. producers would be willing to sell before pulling back production levels will be very influential.. According to Lippe, this figure is likely between $52/bbl and $55/bbl.

The NGL cycle

The NGL market is also nearing the end of an upcycle, but this trend is a result of capacity restraints rather than geopolitical events. However, the NGL market will be just as focused on exports as crude.

"We have to build more raw-mix pipeline and fractionation capacity. We also need to start expanding NGL export terminals because there's nothing that the domestic markets can do to absorb all of the new liquids production," Lippe said.

Most of the raw-mix, or Y grade, pipeline capacity that has been built since 2010 is expandable, which will limit the number of newbuild requirements. However, a great deal of fractionation capacity will be needed to handle all of the liquids and about 300,000 barrels per day of NGL export capacity will be needed in the U.S. by 2022. Over the next three to five years, Lippe expects midstream operators in the NGL space to be as active as they were in the booming 2004 to 2014 period.

"Mont Belvieu [Texas] will be the focal point of much of this construction because of its proximity to West Texas. In 10 years, Mont Belvieu will encompass the entire Gulf Coast from Corpus Christi [Texas] to New Orleans. The liquids storage in the region is by far the largest in the country," Lippe said.

Cycles are shortening in the crude and NGL markets, but if anything, the natural gas cycle is lengthening. Unlike crude and liquids prices, the long-term outlook for gas prices is not positive, according to Lippe.

"Natural gas prices are either going sideways or down. There is almost no possibility of [benchmark] Henry Hub gas prices going above $3 per million British thermal units (MMBtu) for any significant period of time in the next 15 years," he said.

Indeed, the resource base is so large, and the gas exploration companies have made so many advancements in unconventional production, that it is virtually impossible that the U.S. will have gas supply problems for decades.

At the same time, the global LNG market is filled up, so there's not enough demand to support a price increase for any real length of time. One positive is that the market is fairly rigid. Lippe does not expect Henry Hub prices to trade between $2.50/MMBtu and $3/MMBtu and no lower than $2.25/MMBtu for any length of time.

"Natural gas has become hyperabundant and there is no upside on a global basis for natural gas unless there are several extremely cold winters in a row. Even then, that would only cause a price spike for a year or two," he said. ■

—Frank Nieto

needed. Not surprisingly, much of this is needed to transport production out of high-growth areas like the Permian Basin to the Gulf Coast for export.

"The big story over the next three to four years will be infrastructure really catching up to where production is going," Coleman said.

However, there are two concerns related to midstream and exports: short-term bottlenecks and long-term over-capacity. There is a mismatch between when new pipeline capacity comes online in the booming Permian Basin and when marine export terminals under construction come online.

"If these pipelines begin to deliver crude for export and there's not enough dock space, storage, or marine terminal capacity available, you could have a situation where crude is getting bottlenecked in coastal markets," Coleman said.

Building offshore

Many companies have been announcing new terminals with very large crude carrier (VLCC) capability in order to maximize efficiency by being able to carry far more volumes for export. Because inland waters aren't deep enough to handle these vessels, they need to build docks offshore. There is the potential for overbuild and over-capacity should too many move forward, however.

"You've seen a smattering of these large-scale offshore terminal projects in the past few months and they can get quite expensive. They need an underwater pipeline connecting onshore tankage to this offshore platform and that can get very costly very quickly. If you have a situation where there's going to be a substantial amount of competition in the area, you could see a lot of these projects fall by the wayside from the economics of a potential overbuild coming into play," Coleman said.

However, it's possible that integrated crude midstream companies would be able to repurpose or multipurpose some of these facilities and assets.

"You can interchange terminals to export other refined projects or NGL or other energy products. If there is an overbuild on the crude side, you can rationalize some of that capacity for other hydrocarbons to still put it to use," he added.

One of the companies that is planning a large offshore terminal capable of handling VLCC vessels is Enterprise Products Partners LP, which has been one of the most important midstream companies when it comes to adding capacity to increase various hydrocarbons, including crude and LPG. Enterprise is ranked No. 5 on the *Midstream Business* Midstream 50 list.

"The trend with exports has been to break new records almost monthly, with the biggest advances led by crude. … For at least the last three years, we have been very open about our long-term outlook for U.S. crude oil exports and we don't see these trends changing," Jim Teague, CEO of Enterprise Products, said during a conference call to discuss the firm's second-quarter earnings.

This new terminal would be capable of loading and exporting crude oil at about 85,000 barrels (Mbbl) per hour. "What makes this project a natural for Enterprise is the fact that our Houston area systems can aggregate more than 4 MMbbl/d of crude oil, a terminal without supply aggregation really isn't a terminal," Teague said.

Multiple tankers load and unload at the busy Enterprise Products' EHT Terminal along the Houston Ship Channel. This facility is set to be expanded on an adjacent 65-acre site that can handle Suezmax vessels. The Port of Houston is the nation's largest handler of energy and petrochemical shipments.

The company also recently announced it is further expanding its Enterprise Hydrocarbon Terminal (EHT) on the Houston Ship Channel by purchasing an additional 65 acres. This acreage is adjacent to the marine terminal and includes two existing docks and land that will help the company greatly expand its terminaling capabilities, which will include the construction of at least two deepwater docks that can accommodate Suezmax vessels.

Enterprise's network of Gulf Coast marine terminals includes 18 ship docks and eight barge docks. The company also has access to about 125 pipelines, 400 MMbbl of storage and every refinery in the region.

In order to maximize its returns, Enterprise started a vessel bunkering service along the Houston Ship Channel to refuel tanks, which not only adds to the company's bottom line but also helps save time by fueling and loading at one location.

Gasoline demand

Ironically, the crude oil production renaissance in the U.S. has occurred at a time when domestic gasoline demand is decreasing as automobiles become more fuel efficient, public transportation becomes more widespread, and workers shorten their daily commute by either moving closer to work or working remotely. Most importantly, the automotive industry is beginning to switch from the internal combustion engine to electric motors.

"We're in the early twilight of oil demand as global auto manufacturers turn to electric vehicles. The future of automobiles is all-electric, and the biggest single end-use market for crude oil is as a fuel for automobiles. I realize this perspective is not the consensus view, but anyone who denies the threat of all-electric vehicles out of hand is whistling past the cemetery. The majority of global oil demand is from transportation fuel. We're talking the beginning of the end of oil as the dominant transportation fuel," Lippe said.

At this time, the conversion to electric vehicles is primarily concentrated in developed nations including the U.S., Germany and England. However, global demand for crude oil is actually increasing as emerging markets grow and global demand isn't expected to decline for several decades.

"Most of the crude demand growth will be coming from developing markets over the next two decades. Developed markets are very much in a plateauing phase. In our view, the demand for gasoline in this country either peaked last year or will peak this year and will start to slowly decline. Similar stories are starting to play out in the developed European market," Coleman said.

Wood Mackenzie anticipates that the impact of electric vehicles won't truly be felt on a global basis until sometime in the 2030s. Most importantly, the trend to electric vehicles will occur when global crude oil demand is higher than it is today.

In 10 years when we look back at 2018, it's very likely that many things will be different in 2028. However, it's certain that the biggest industry story will revolve around the perpetual growth of U.S. energy exports.

LNG's growth

Although the U.S. energy renaissance began with gas, the year 2019 is poised to be perhaps the biggest yet for the LNG industry as domestic export capacity is set to nearly double to

Enterprise Products Partners' Marine West Terminal at Beaumont, Texas, is part of a complex that features five ship and six barge docks along the Neches River with import/export capabilities, 12.1 million barrels of storage capacity for crude oil, refined products and petrochemicals, and access to 12 refineries.

10 billion cubic feet per day (Bcf/d). However, there is the risk that a lack of new LNG facilities after this next expansion will result in a supply gap over the next decade.

Current LNG export capacity from the U.S. comes from Cheniere Energy Inc.'s Sabine Pass terminal in Cameron Parish, La., and Dominion Energy's Cove Point terminal in Calvert County, Md. Capacity is set to grow significantly next year as a result of several new facilities coming online along the Gulf Coast and Atlantic Coast. These facilities include Freeport LNG's terminal in Texas; Kinder Morgan Inc.'s Elba Island, Ga., terminal; Cheniere Energy Inc.'s Corpus Christi, Texas, terminal; and Sempra LNG's Cameron, La., terminal.

Despite this growth, forecasts anticipate far more export capacity will be required to handle increased domestic production and global LNG demand. Cheniere officials reported that nearly 16.5 billion cubic feet per day (Bcf/d) of additional LNG will be required by meet global demand by 2030.

Multiple companies have proposed new LNG plants and terminals, but they have not received enough support via long-term commitments from buyers necessary to justify the large expenses involved in building these facilities.

Should these projects be pushed back or canceled, it's likely that more midstream capacity will be added to help fill the supply gap, according to a recent Alerian report titled, "U.S. LNG Export Growth and the Benefits to Midstream."

"Without the ability to export natural gas on tankers as LNG and via pipelines to Mexico and Canada…the natural gas supply in the U.S. would overwhelm domestic demand. This would have negative implications for natural gas prices and limit production growth," the report said.

The lack of new LNG terminals will likely result in an increased need for new or expanded gathering pipelines and natural gas processing plants to move and process the increased production to existing export terminals. Expansion projects are cheaper and faster to complete than newbuild projects. The permitting process is easier and expansions aren't as dependent on long-term contracts to move forward.

"Production growth benefits midstream companies as volume-driven businesses. More natural gas means more volumes to gather, process and transport, and that requires more infrastructure," according to the Alerian report.

Though the bulk of U.S. LNG export facilities are located in Texas and Louisiana, they will utilize production from around the country. This will require both new and expanded pipelines to transport volumes from all of the major plays in the U.S., including basins as far apart as the Appalachian and the Permian.

Because there's such a high level of interconnectedness between natural gas pipelines in the U.S., facilities like the Sabine Pass terminal have access to every producing region in the Lower 48 states east of the Rockies, the report said.

Much of these supplies will be used to meet the still-growing demand for LNG in Asia. Japan is the largest importer of LNG, but China has been leading the way in terms of demand growth. In 2017, China was responsible for 44% of the global uptick in LNG imports.

A potential trade war with China would negatively impact the U.S. LNG industry and create another headwind for projects that have not yet secured a final investment decision (FID).

However, the Alerian report noted that China was one of 40 countries that imported LNG in 2017 and the U.S. exported it to 25 of those countries. A customer base without China wouldn't be ideal, but other customers could help bridge that loss. The use of spot markets and short-term contracts is a way to quickly develop new trade partners.

"While China is a major player in the LNG market, it's not the only customer. … Europe is clearly a market for U.S. LNG exports as countries look to diversify their gas supply from Russia," the report added.

Additionally, the Trump administration may be in the midst of a trade spat with China, but the administration is negotiating trade agreements with European countries that could benefit the U.S. LNG industry. Still, Europe's LNG demand is dwarfed by that of China's, and while the threat of a trade war is still imminent, it's likely that FIDs for new LNG terminals will remain tough to secure. ■

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Exports Fuel Market Uncertainty

The U.S. is primed for what many have called "energy independence," but at what cost?

By Michael Hinton

More than a century ago, the U.S. was the largest producer and exporter of hydrocarbons, and in the late 1950s and early 1960s, the country was considered a net energy exporter, producing and shipping more than it imported. However, as most know, extreme growth in U.S. domestic consumption and declining production eventually led to the U.S. becoming the world's largest importer of petroleum and also to the banning of crude oil exports.

Today, the U.S. is seeing a picture much like that of the '50s and '60s. Thanks to advances in horizontal drilling and technology improvements in hydraulic fracturing, the country is once again a major oil and gas exporter.

Based on production forecasts from the U.S. Energy Information Administration (EIA), the U.S. is on track to become the world's largest oil producer and will account for more than half of the worldwide growth in oil production capacity over the next five years. With global demand for NGL, LNG and petroleum increasing, the U.S. could become one of the world's largest exporters of these commodities.

To many, the U.S. seems to be poised to achieve "energy independence" once again as it rejoins the ranks of the world's largest energy producers and exporters. Nevertheless, today's global energy market looks vastly different than it did half a century ago, and energy businesses and consumers will both be impacted by the uncertainty this so-called energy independence brings.

Global demand outlook

In 2017, global energy demand rose by 2.1%—more than twice the previous year's rate—and more than 70% of this demand was met by oil, natural gas and coal. Due to strong economic growth, China and India accounted for more than 40% of the rise in demand. Over the next 25 years, these two countries will each roughly provide about one-quarter of the growth in energy demand, according to the "BP Energy Outlook" report.

Just this year, U.S. net gas exports more than doubled as gains were seen with the expansion of domestic LNG facilities, which averaged exports of

2.72 billion cubic feet per day (Bcf/d) in the first half of this year. The EIA reports that another four LNG facilities are under construction and slated to enter service by the end of 2019, ultimately increasing U.S. LNG export capacity to 9.6 Bcf/d.

Ethane returns

Ethane prices recently hit a four-year high as global demand has increased. The U.S. is producing so much ethane, thanks to the shale revolution, that some of it is being "rejected," or mixed into the methane natural gas stream. With a surplus in liquids, the race is on for U.S. energy companies to expand NGL infrastructure while providing global markets with ethane and propane. For instance, earlier this year, Energy Transfer Partners LP and Satellite Petrochemical USA Corp. entered into an agreement to construct a new export terminal on the U.S. Gulf Coast to provide ethane to Satellite for consumption at its ethane cracking facilities in China.

As far as oil supply and demand goes, industry experts are optimistic that global oil demand will continue growing over the next 20 years as growth in petrochemicals and air travel will continue supporting long-term oil demand. As the U.S. shale revolution continues, the country's energy businesses will have to find near-term solutions to handle challenges such as uncertainties around the takeaway capacity out of the Permian, the impact of steel tariffs on U.S. shale development and pending sanctions on global oil flows.

As the global demand for energy expands and the U.S. continues ramping up its exports, energy companies must be prepared for the risks associated with inevitable domestic supply and demand imbalances.

Domestic price volatility

With U.S. natural gas production up and the country becoming focused on gas, many industry experts are concerned that global demand is shifting needed supply from the U.S. In fact, the country's average deficit in natural gas storage over the past five years has energy businesses and consumers concerned that the winter months of 2018-2019 will once again contribute to price disruptions.

Even if the U.S. were to slow exports in an attempt to meet demand, energy companies would still struggle with the country's current pipelines and infrastructure—especially in heavily populated areas during extreme hot or cold temperatures. Just last winter, the Northeast experienced extreme winter conditions that resulted in power outages and natural gas prices increasing by 60x to 70x their typical rates.

Because of insufficient pipeline capacity in the region to meet higher demand, the Northeast found itself looking to alternative sources—including importing LNG from Russia.

Natural gas is not only the fuel of choice for many U.S. residential areas—it is also being included in a large segment of new power plant proposals. What's more, many coal, oil and nuclear power plants, which have fuel stored on site and are essential for reliability when natural gas is in short supply, are retiring under increasing economic and environmental pressures.

Midstream lag

The expansion and building of new gathering systems, pipelines, terminals and stations to handle new production is lagging far behind the growth in production. That said, the timely availability of fuel is critical, highlighting the importance of fuel delivery logistics. In order to navigate an infrastructure that oftentimes does not transport enough supply to meet demand, energy businesses must have complete, real-time portfolio and market visibility, coupled with advanced analytics. These capabilities can help businesses determine hedging and risk strategies as the market continues evolving.

There's no denying that the global export market presents vast opportunities for U.S.-based energy companies, but it also presents new challenges that expose U.S. businesses and consumers to unparalleled risk that must be properly mitigated to ensure future success.

As the U.S. continues integrating into the world energy market, industry participants must be equipped with the latest capabilities in forecasting, purchasing and hedging strategies and fuel supply management capabilities in order to navigate market uncertainty.

Improved forecasting

Forecasting of energy prices should consider more than just production rates and weather. Export markets, especially LNG, must also now be considered. As more energy is exported from the U.S., integration with the world's gas markets will also increase, which means worldwide benchmarks for natural gas are more likely to impact U.S. prices. LNG may only end up consuming 15% of the U.S. gas supply, but because commodity prices swing widely with marginal impacts upon supply and demand, the impact on prices of LNG exports and the other factors described above can be significant.

In the past, domestic production points were linked directly to refineries. Now that the U.S. has further integrated into the world energy market, businesses now have the option to export LNG, NGL and crude oil to other markets where prices exceed domestic prices by more than the additional transportation costs. That said, with more rewards come more complexity and risk.

Today, exports present a more complex value chain that is global in nature with more options on what to do with assets and commodities.

For a U.S.-based energy company to remain successful, it must have real-time portfolio visibility coupled with advanced analytic capabilities to understand the real options embedded within various contracts and assets and the ability to properly value and hedge them—from production to storage to liquefaction to regasification.

Hedging strategies

Forward-looking energy companies are reconsidering their strategies on purchasing and hedging supplies. Aside from the volatility of prices that could occur due to LNG exports, the U.S. will be more integrated with world markets.

U.S. power producers will be competing with export markets, as well as domestic chemical plants and U.S. consumers, for natural gas supplies. This might lead to a general rise in prices over time and to even more price volatility as uncontrollable factors such as weather events impact residential and business consumers of natural gas. A strategy that simply looks at natural gas production growth and adjusts for weather is unlikely to reliably predict prices or help determine hedging strategies.

Fuel supplies will need to be managed more actively, especially going into seasons of extreme weather. For example, a disruption in supply to a LNG facility may cause the LNG operator to source supply from somewhere else, resulting in fuel disruptions for fleets. Supply interruptions and price volatility will also make storage even more important for generators than it currently is, as it can be utilized for more than just mitigating demand changes due to weather.

In situations such as a pipeline outage, active management with pre-planned mitigation activities can save a business millions of dollars in a very short period of time.

Ensuring success

As the U.S. continues to integrate into the world energy market, supply chain and logistics management will become more complex, meaning businesses must be equipped with real-time portfolio visibility and advanced analytics. Forecasting and analyzing prices, determining the impact of those prices, planning and executing effective hedging strategies, and active management of supply logistics and imbalances are all critical when supply and demand are mismatched.

With the integration of domestic gas into the world market and the impact of commodities such as crude oil, NGL and LNG on natural gas prices, power generators need to make sure they have a comprehensive system that can handle analysis for multiple commodities, a variety of modes of transportation and international trading and logistics.

Enterprise commodity trading and risk management software, such as Allegro Horizon, provides companies with total control and complete visibility across marketing, trading, logistics, inventory, accounting and settlement for both domestic and international operations. This commodity trade risk management software can help mitigate risk and capitalize on growth opportunities as supply and demand patterns shift. ■

***Michael Hinton** is chief strategy and customer officer for Allegro Development.*

The 4 Challenges

Important trends could buffet the growing U.S. export market.

By Jeff Lee

Since the shale gale kicked into high gear in the last decade, North America's energy landscape was fundamentally transformed. Encouraged by recent high prices, full-throttle development from shale producers had led to record exports. Crude exports (excluding Canada) have risen from zero in 2015 to about 1.5 million barrels per day (MMbbl/d), natural gas net trade has swung in the same time period from a deficit of 3 billion cubic feet per day (Bcf/d) to a surplus of 1 Bcf/d, largely through pipelines to Mexico and LNG via the Gulf Coast.

A tugboat inches a tanker toward its dock at Corpus Christi, Texas, to take on a load of American crude oil. *Source: Port of Corpus Christi*

But can it last?

American oil and gas created its own ecosystem but it is not isolated from the world. In particular:

- Prices affect worldwide production and consumption;
- Infrastructure development is complex and slow;
- Trade wars and politics disrupt logistics and purchasing patterns; and
- Economic health determines demand and investment.

The challenges for exporters mostly arise from these four areas.

$100 again?

Since hitting bottom at $42 per barrel (bbl), West Texas Intermediate (WTI) has staged a massive comeback to $60-$70. Natural gas at Henry Hub has also rallied above $3 per million British thermal units (MMBtu) on the back of depleted inventory and strong summer demand. Speculation abounds for oil to hit $100/bbl and natural gas to spike again.

We considered nine factors to watch in the oil market supporting the upward trajectory. Global supply and demand are finely balanced, but the new Iranian sanctions could disrupt up to 2 MMbbl/d of supply and Saudi Arabia's spare capacity has dwindled down to less than 2% of global demand.

With low breakeven costs and plentiful capital, shale production has outpaced infrastructure, resulting in an export bottleneck and a widening Brent-WTI price spread. The Saudis are inclined to manage the $70/bbl to $80/bbl Brent crude range as it stabilizes their budget. Market sentiment remains very strong, and pricing backwardation is persistent. All signs point to a continued uptrend in the near term.

The woes of gas

Natural gas, on the other hand, is still mired in a decade-long struggle of overcapacity. Slowly but surely, demands have been created in power, transportation and chemical sectors domestically. A massive LNG export industry has sprung up since 2016 to arbitrage the overseas market. Prices in Asia and Europe have recovered as the commodity enjoys widespread adoption for power generation.

The Japanese spot price has sustained above $10/MMBtu, providing a respectable margin for American exporters. But with underutilized LNG facilities globally, any new large-scale projects are unlikely to produce decent rates of return.

During the 2014-2016 downturn, producers and service providers alike made brutal cost adjustments and turned the U.S. into a major oil and gas exporter. To accommodate surging exports, companies have been rushing to build docks, terminals, LNG plants, vessels and pipelines. Natural gas production and pipeline infrastructure have historically been near the Gulf Coast where exporting takes place.

Connectivity is therefore straightforward after initial LNG plant conversion from gasification to liquefaction. In South Texas, a few major pipelines were quickly constructed after the 2013 Mexican energy reform and Mexican exports promptly doubled to 4 Bcf/d. Here again, infrastructure is relatively simple.

The growth driver

Ever since the 40-year crude oil export ban was lifted in 2015, crude and petroleum liquids exports have surged along with gasoline and distillate. The growth driver, the Permian Basin, has been wrangling with sand, water, labor, trucks—and now limited pipeline space similar to the Bakken and Marcellus shales in their heydays. Production is at a record high but will likely flatten out next year as producers, exhausted of options, leave drilled wells uncompleted.

A few new takeaway pipelines are slated to come online by the end of 2019, which is reflected in the wide but narrowing (toward 2020) Midland-Gulf Coast spread. Ideally, excess supply would be absorbed by additional local refining. However, the challenges of building new refineries and reconfiguring existing heavy crude refineries on the Gulf Coast proved to be insurmountable.

Elsewhere, ports and midstream operators from Houston to Freeport to Corpus Christi in Texas are scrambling to expand tank terminals and improve access to vessels, especially the most efficient very large crude carriers, which currently can only be accommodated at Louisiana's LOOP terminal. With speed and capital behind all these export projects, time is the only obstacle. In fact, analysts say that the eventual sustained export level is 4 MMbbl/d but by the time all facilities on the books are completed there may be 1.5 MMbbl/d to 2 MMbbl/d of excess export capacity.

Trades, sanctions, reforms

On the trade and politics front, President Trump's imposition of "America First" policies looms large. In September, China slapped a retaliatory 10% tariff on U.S. LNG imports while leaving crude oil trade alone. It is noteworthy that Chinese crude imports from the U.S. rose from next-to-nothing in 2016 to 377,000 barrels per day in July and then dropped to zero in August. U.S.-to-China LNG shipment has also dropped sharply to near zero recently.

While alternative buyers are readily available for now, it is a long-term threat to lose a large, stable customer in a well-supplied market.

As for the sanctions on Iran that began in November, the hardline approach of the Trump administration has chilled European and Asian buyers of Iranian crude. Since the sanction announcement in May, Iranian oil shipment dropped by about 1.5 MMbbl/d as some of the biggest customers in India and Europe drastically cut back. China is expected to circumvent it due to its relative insularity to the dollar and U.S. banking system, especially while it is cutting American imports.

Iran's loss, along with Venezuela's spiraling production, is a boon to all other oil exporters as they make up the shortfall.

The conclusion of NAFTA negotiations left energy flow across Canada and Mexico largely untouched.

However, Mexico's new president won on a populist platform that favors Pemex. Although recent, successful foreign oil and gas investments and access to cheap U.S. gasoline and natural gas have softened his nationalistic stance, that country's energy reform remains highly vulnerable to public sentiment. The upside potential for Mexican export growth is thus limited.

Crisis watch

Despite their lone strength in the commodity space, oil and gas ultimately rely on economic use. Signs of trade wars hurting commerce and capital investments have surfaced since this summer. China is deleveraging and trying to contain the damage from slowing growth and trade spats with the U.S. Emerging markets had a cascade of currency collapse and inflation spikes, with Turkey and Argentina leading the pack.

If a 1998-style currency and debt crisis develops, it will likely wash ashore here. Europe's outlook is gloomy amid the ending of monetary stimulus, the Brexit quagmire and the Italian political standoff. Italy has an outsize government bond market with fast-rising yields; investors are nervous about the potential unraveling of the EU yet again.

The U.S. economy has become somewhat insulated from high energy prices. Yet central bank policy divergence from Europe and others resulted in rising yields and interest rates and a strong dollar. An ill-timed, late-cycle fiscal stimulus in the form of corporate tax cuts also increased the systemic fragility and reduced the political tools to react to an eventual slowdown. Unbalanced economic growth detached from the rest of the world is unlikely to be sustainable. In fact, the International Monetary Fund recently reduced its 2019 global growth forecast from 3.9% to 3.7%, pointing to trade wars and high oil prices as culprits.

Dominance continues

Given the robust economic growth with no sign of recession and muted geopolitical risk, sentiment is remarkably positive with few catalysts to dislodge oil from the uptrend for the foreseeable future.

The worldwide movement away from coal and nuclear to renewables or cleaner energy also adds to the impetus for natural gas. Apart from a general economic recession, the few bearish factors are mildly threatening to U.S. energy dominance. Challenges remain, but the country's structurally low-cost basis and newfound agility should allow it to maintain and even capture greater market shares in the coming decades. ■

***Jeff Lee** is the principal of Vancouver-based Kronos Management LLC.*

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The LNG Shortfall

A supply gap of up to 200 million tonnes per year in 2030 is the prize for U.S. liquefaction projects as gas exports take center stage.

By Scott Weeden

The U.S. has been at the forefront of international LNG trade since its inception. The first shipload of LNG was delivered by the *Methane Pioneer* in 1959 from Lake Charles, La., to Canvey Island, U.K.

Ten years later in 1969, the Kenai LNG plant in Alaska, owned by Phillips Petroleum Co. and Marathon Inc., shipped the first LNG cargo to Japan, opening up the LNG trade to Asia. The Kenai plant, small by today's standards at only 1.5 million metric tons per year (mt/y) [equal to 210 million cubic feet per day (MMcf/d)], was the largest LNG plant at that time and continued operation until the final cargo was sent in 2015.

Those were much simpler times in the LNG business. Today, the U.S. is setting sail on its latest excursion into the global LNG export business, where there are much more complex negotiations and contracts, financing and fierce competition as natural gas demand is spurring growth in LNG supply.

"We tend to view things based on our supply and demand here, and what we can do as far as moving our gas outward. But I think that we have to look at and understand that there are other folks out there that have resources competing with the U.S.," Bob Broxson, managing director in BDO's energy disputes practice, told *Midstream Business*. "I think we have a great story to tell from a pricing and supply perspective, but we do need to be aware of what the competition is," he said.

Greg Haas, director of integrated oil and gas for Stratas Advisors, agreed with the pricing perspective.

"For the LNG markets, we think it is a long-term trend that North American gas, including gas from Canada, will be at a significant discount and can be liquefied and delivered to consuming nations at lower costs than many competitors around the globe," he told *Midstream Business*.

Shift in dynamics

The recent McKinsey Energy Insights buyers survey shows the purchase dynamic has shifted considerably. Commenting on the findings of the survey conducted across about 60 LNG buyers worldwide that

LNG storage tanks at Shanghai, China, stand ready to receive LNG from the U.S. and other suppliers. Expanding worldwide infrastructure supports growing trade in the valuable commodity. *Source: Shutterstock/Chuyuss* account for about 85% of the global LNG, Dumitru Dediu, associate partner in the Amsterdam office said, "We see there is a stronger preference for shorter term contracts, more innovative pricing formulas and a high demand for flexibility. "This demand is driven by a lot of non-traditional buyers, especially in Southeast Asia, which will amount to as much as 50% of the LNG demand growth."

To meet that LNG demand, a new round of construction worldwide is underway, with new final investment decisions (FIDs) being announced and new construction underway primarily in the U.S. Sorting out the complexities on the global stage of today's LNG market will be the major task of producers, midstream pipelines, LNG plant developers, shippers and LNG buyers.

Price drives demand

A majority of contracts for LNG in Asia have oil-linked prices. Security was the main driver for countries like Japan and South Korea, which have little or no oil and gas resources. By paying a higher price, the countries wanted to assure energy security. However, that scenario is changing as seen by the preferences for shorter-term contracts and flexibility.

The U.S. is re-entering the world LNG export stage at a key moment in pricing history.

"There is an enormous resource base within the Lower 48, and U.S. Henry Hub operations are going to remain low for some time, we think," said Neil Beveridge, senior analyst in AB Bernstein's Hong Kong office.

With Henry Hub prices at $2 per million British thermal units (MMBtu) to $3/MMBtu, "you can get LNG delivered to the Pacific Basin for $8/MMBtu to $9/MMBtu," he continued. "The biggest incremental buyer over the next decade is going to be China. China is going to account for over 40% of global demand growth."

It is not only the price that will drive U.S. exports, but also current lower capital costs for construction. "For a period of three years, there was no North American LNG capacity that took an FID. The global LNG market was oversupplied and prices were low. There was a big tranche of liquefaction capacity under construction. It wasn't clear how much LNG the market was going to need and when," noted Amber McCullagh, associate with RBN Energy.

"What has happened over the last one to one and a half years is that construction costs have started to come down. The cost of delivering LNG is lower. We've seen a renewed interest globally in environmental goals. We're seeing both an increased appetite for LNG globally as well as increased competition with other fuels. It could be coal displacing oil in power generation, or it could be backstopping renewables serving loads that previously came from coal or crude oil," she added.

Haas pointed out that Stratas Advisors' 2018 long-term price forecast for Henry Hub showed that it will take until 2031 for prices to double to about $6/MMBtu, which means a compound annual growth rate of 4.7% in prices from 2017 levels.

"In 2017 the gas price was $2.96/MMBtu. We get to $5.95/MMBtu in 2031. In 2040, we're at $7.12/MMBtu," he added.

54 possibilities

In June, the U.S. Department of Energy (DOE) released a study on "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports," which was prepared by NERA

Economic Consulting. Combining three U.S. supply cases, three U.S. demand cases, three international demand cases, and two international supply cases in all possible combinations yielded a total of 54 different scenarios for LNG exports.

"Under reference case supply assumptions, prices are much lower and in a narrower range when international LNG demand varies. These central cases have a combined probability of 47% and prices range from \$5/MMBtu to about \$6.50/MMBtu in 2040," according to the report.

"About 80% of the increase in LNG exports is satisfied by increased U.S. production of natural gas with positive effects on labor income, output and profits in the natural gas production sector," the report added.

"LNG exports affect the U.S. economy in multiple ways. Their direct impacts are increases in natural gas production, LNG export revenues, wealth transfers in the form of tolling charges on LNG exports and domestic natural gas prices. Higher LNG export demand that leads to an increase in natural gas production to meet the demand puts upward pressure on the domestic wellhead and Henry Hub prices," the report continued.

Chasing the prize

Almost every forecast of supply and demand for LNG through 2030 is the same—a gap of 100 MMmtpy to 120 MMmtpy.

"Next year there is a lot of supply coming on the market principally from a lot of U.S. projects starting up," said Bernstein's Beveridge. "The longer-term picture is that the industry is not investing enough in new LNG capacity. We've been calling for the start of a new cycle since the start of 2018.

"We've gone through this period over the last few years worried about a gas glut. Now I think people are starting to worry about a gas deficit," he emphasized. "There is a lot of capacity coming in 2018 or 2019, and 2020 looks OK as well. As we come into 2021, 2022 and 2023, there's just not enough liquefying capacity being built. It takes five years to build a project. It is pretty clear there is going to be a supply deficit through the early 2020s."

Beveridge added, "Over the next two to three years, assuming the global economy holds, which is looking like a greater risk, there will be a large number of projects moving forward into construction."

McKinsey's Dediu noted that McKinsey's Global Gas Outlook "shows there will be a gap of around 100 MMmtpy to 120 MMmtpy by 2030. It is a supply gap that we will need to fill with new projects. A large part will be built by Qatar, who announced an additional 33 MMmtpy with additional North Field expansion.

"About half of the supply gap will be filled mainly with projects that already should be competitive or taken up by buyers. The remainder of that will be filled with competition from other conventional projects and U.S. projects," he continued.

Growth support

In its August investor presentation, Cheniere Energy Inc. stated, "Supply/demand fundamentals support continued LNG demand growth worldwide with forecast global LNG trade growth of more than 200 MMmtpy by 2030.

China remains the prize for LNG demand.

"We've got to deal with and understand who is competing with us. You've got the Russians building a pipeline that will go to China. When we look at the number of customers out there that are actually buying LNG, we tend to focus on places like China obviously, but we have some hindrances to that right now," Broxson said.

"But there are a lot of other places like Europe that are looking to have more competitive advantage as opposed to being tied to one supply out of Russia," he added.

"Will we see China sign up for a material volume of U.S. LNG? It is going to be a very political question. If relations between the U.S. and China continue to deteriorate, then it is difficult to see Chinese companies signing up U.S. LNG," noted Beveridge.

"On the other hand, if you think about the \$300 billion to \$350 billion

The Elba Island, Ga., liquefaction project consists of 10 small-scale modular units. The first will begin production in first-quarter 2019. *Source: Kinder Morgan Inc.*

Schedules for LNG Export Plants

Company	Project	Location	Capacity	DEIS*	FEIS*	FERC Certificate Decision	Final Investment Decision	Construction Start	Commercial Operation	SPA/HOA/MOU*
Pending Applications										
Freeport LNG Development	Freeport LNG Train 4	Freeport, Texas	1 train, 5.1 MMmtpy		Nov. 2, 2018	Jan. 31, 2019	2019	2019	2023	Sumitomo Corp. of Americas, HOA, 2.2 MMmtpy
Sempra Energy	Port Arthur LNG	Port Arthur, Texas	2 trains, 13.5 MMmtpy	September 2018	Jan. 31, 2019	May 1, 2019		2018	2022	PGNiG, SPA, 2 MMmtpy; Korea Gas Corp., MOU
Driftwood LNG LLC	Driftwood LNG	Calcasieu Parish, La.	5 trains, 27.6 MMmtpy	Sept. 14, 2018						
Cheniere Energy	Corpus Christi LNG Stage 3 Project	Corpus Christi, Texas	7 trains, 11.45 MMmtpy		Jan. 18, 2019	April 18, 2019				
Texas LNG Brownsville LLC	Texas LNG	Brownsville, Texas	2 trains, 4 MMmtpy	October 2018	March 15, 2019	June 13, 2019				
Gulf LNG Liquefaction Co.	Gulf LNG	Pascagoula, Miss.	11 MMmtpy	November 2018	April 17, 2019	July 16, 2019				
NextDecade Corp.	Rio Grande LNG	Brownsville, Texas	6 trains, 27 MMmtpy	October 2018	April 26, 2019	July 25, 2019	Third Quarter 2019	2019	2022	
Eagle LNG Partners Jacksonville LLC	Jacksonville Eagle LNG	Jacksonville, Fla.	3 trains, 1.5 MMmtpy		April 12, 2019	July 11, 2019		First Quarter 2018	Third Quarter 2019	
Exelon Generation	Annova LNG	Brownsville, Texas	6 trains, 6 MMmtpy	December 2018	April 19, 2019	July 18, 2019	Fourth Quarter 2019	First Quarter 2020	2024	
Venture Global LNG	Calcasieu Pass LNG	Cameron Parish, La.	9 trains, 10.8 MMmtpy			Jan. 22, 2019	Early 2019	Early 2019	2022	Repsol, SPA, 1 MMmtpy; BP, SPA, 2 MMmtpy; PGNiG, SPA, 1 MMmtpy; Galp, SPA, 1 Mmmtpy; Shell NA LNG LLC, SPA, 2 MMmtpy; Edison SpA, SPA, 1 MMmtpy
Venture Global LNG	Plaquemines LNG	Plaquemines Parish, La.	18 trains, 20 MMmtpy	November 2018	May 3, 2019	Aug. 1, 2019	Late 2019		2023	PGNiG, SPA, 1 MMmtpy
Pembina Pipeline Corp.	Jordan Cove LNG	Coos Bay, Oregon	5 trains, 7.8 Mmmtpy	February 2019	Aug. 30, 2019	Nov. 29, 2019				
Alaska Gasline Development Corp.	Alaska LNG	Nikiski, Alaska	20 MMmtpy							
Projects in Pre-filing										
Commonwealth Projects LLC	Commonwealth LNG	Cameron Parish, La.	8 trains, 8 MMmtpy			First Quarter 2019	Third Quarter 2020	Fourth Quarter 2020	First Quarter 2024	
Energy World USA	Port Fourchon LNG	LaFourche Parish, La.	10 trains, 5 MMmtpy							
Pointe LNG LLC	Pointe LNG	Plaquemines Parish, La.	3 trains, 6 MMmtpy					First Quarter 2021	2025	
Projects Approved but Not Under Construction										
Energy Transfer	Lake Charles LNG	Lake Charles, La.	3 trains, 15 MMmtpy		2015	2016			2025	
LNG Ltd.	Magnolia LNG	Lake Charles, La.	4 trains, 8 MMmtpy			April 15, 2016	December 2018	Mid-2019	Late 2022	Meridian HLNG Holding Corp., binding agreement, 2 MMmtpy
ExxonMobil	Golden Pass LNG	Sabine Pass, Texas	3 trains, 15.6 MMmtpy	March 2016	July 2016	December 2016				
Sempra Energy	Cameron LNG Trains 4 and 5	Hackberry, La.	2 trains, 9.97 MMmtpy							
Sempra Energy, Total SA	Cameron LNG Phase 2	Hackberry, La.								
Projects Proposed to U.S. Coast Guard/MARAD										
Company	**Project**	**Location**	**Capacity**	**DEIS**	**FEIS**	**MARAD* Decision**	**Final Investment Decision**	**Construction Start**	**Commercial Operation**	**SPA/HOA/MOU**
Delfin Midstream	Delfin LNG	Gulf of Mexico	4 Floating LNG plants, 13 MMmtpy			March 13, 2017	2018		2022	China Gas Holding, MOU, 3 MMmtpy

Abbreviations: MMmtpy-million metric tons per year; DEIS-Draft environmental impact statement; FEIS-Final environmental impact statement; SPA-Sales and purchase agreement; HOA-Heads of agreement; MOU-Memrandum of understanding; MARAD-U.S. Maritime Administration.

Source: Federal Energy Regulatory Commission trade deficit that the U.S. has with China, LNG could be a key part of that solution. If 20% of China's gas needs by 2030 were supplied by the U.S., which would be around 10 Bcf/d to 12 Bcf/d, it could narrow that trade deficit by $50 billion over several years," he explained.

Skirting the tariff

Much of the demand for LNG in China comes from the country's effort to reduce air pollution in its major cities. China has expanded its Blue Sky policy, which will require additional LNG to replace coal.

One advantage that the major oil companies have over domestic producers is being able to source LNG from multiple countries. According to an October article, ExxonMobil is actively pursuing business in China while expanding output in places like Papua New Guinea and Mozambique, an anonymous ExxonMobil manager told *Reuters*.

Exxon plans to participate in building an import terminal in Huizhou, China. While U.S. companies face a 10% tariff for LNG exports to China, ExxonMobil can deliver LNG to China from Qatar, Australia and Papua New Guinea with no tariff.

The *Reuters* article stated that ExxonMobil is among top-ranked companies in many industries that are focusing on China, regardless of the trade dispute.

Filling the gap

As of Feb. 26, 2018, DOE had received applications for a total of 55.04 Bcf/d of LNG exports to non-Free Trade Agreement countries. Again, there is virtually no chance that this level of LNG exports could be reached before 2040 and only a 2% chance that this level could be reached or exceeded by 2040, according to the DOE report.

At this time there are two U.S. LNG plants actively exporting LNG:

- Sabine Pass in Louisiana; and
- Cove Point in Maryland.

Four other facilities are under construction:

- Freeport LNG and Corpus Christi LNG in Texas;
- Cameron LNG in Louisiana; and
- Elba Island in Georgia.

Cheniere's Sabine Pass Trains 1 through 4 (18 MMmtpy) in the Cameron Parish, La., plant are in operation. Commissioning activities are underway on Sabine Pass Train 5 (4.5 MMmtpy). The company is progressing Sabine Pass Train 6 (4.5 MMmtpy).

Corpus Christi LNG Train 1 has an in-service date of the first half 2019 and Train 2, the second half. Train 3 is 30.1% complete with an in-service target of second-half 2021. The total for these three trains is 13.5 MMmtpy.

A Federal Energy Regulatory Commission (FERC) application was also filed for Corpus Christi Stage 3, a capacity expansion of about 9.5 MMmtpy adjacent to the Corpus Christi LNG plant.

"It is well understood that China needs more LNG over the long term. We view U.S. LNG as an important variable to help resolve trade issues as U.S. LNG into China is beneficial to both nations," Jack Fusco, Cheniere's president and CEO, said during the second quarter earnings call in August. "China is an important growth market for Cheniere, and we continue to build and solidify relationships with key Chinese counterparties."

In the first half of 2018, U.S. LNG exports increased 65% to more than 10.3 MMmt. The U.S. is now the fifth-largest LNG supplier. Australian exports were up 20% in the first half to more than 32 MMmt, Anatol Feygin, Cheniere EVP and chief commercial officer, said during the call.

"Despite more than 11 million tons of new supply added to the market in the first half of 2018, we're seeing extremely strong demand mostly in Asia keeping the market tight. These price signals provide further evidence the market is calling for additional investment in liquefaction infrastructure," he said.

BDO's Broxson pointed out, "What Cheniere is doing is building some of their own pipeline facilities, basically to insure they can get gas to their facilities so they can remain competitive and have supply available. I think you're going to see a lot of companies take on new pipeline positions."

Storm delays

Work is progressing on Freeport LNG's inaugural train.

"After all of our delays we are looking at startup for Train 1 in the third quarter 2019. Trains 2 and 3 are scheduled for startup in the first quarter 2020 and the second quarter 2020, respectively," said Sig Cornelius, Freeport LNG president and COO. Each train has a capacity of 5 MMmtpy.

"We are progressing on our fourth train. We need to sell between 70% and 80% of the capacity to reach FID on that project," he added.

Freeport LNG announced on Sept. 5 a binding heads of agreement (HOA) with Sumitomo Corp. of Americas to negotiate a liquefaction tolling agreement (LTA) for 2.2 MMmtpy for 20 years, which represents about 50% of capacity.

"We are planning to close on our commercial offtake agreements and get all of the regulatory approvals by early 2019. We are out for bids on the engineering, procurement and construction contract. We are targeting an FID on this project by mid-2019. If all that comes together, we would have commercial operations start up in mid-2023," Cornelius continued.

Freeport has a tolling business model as a liquefaction facility.

"The tollers are responsible for arranging to bring gas to our facility so we take custody at the inlet of our pretreatment facility, and then we are responsible for loading it on the ships," he explained. "We are very much aware of what the price for LNG is around the world and netbacks to the various markets, including shipping costs, gas costs and liquefaction costs. We have to understand the entire market."

Cove Point

In April, Cove Point LNG became the second active U.S. LNG export facility. It has nameplate capacity of 5.25 MMmtpy. Thomas F. Farrell II, chairman, president and CEO for Dominion Energy, said in the company's second-quarter report in August, "The Cove Point liquefaction project achieved commercial in-service early during the second quarter and since then has delivered 19 commercial cargoes representing over 60 Bcf of LNG."

Farrell told *Reuters* in June that "You'll see a very significant increase in U.S. natural gas coming to Asia and in particular Japan."

Dominion signed 20-year agreements for the plant's capacity to GAIL (India) for 2.3 MMmtpy and ST Cove Point, a joint venture between Sumitomo Corp. and Tokyo Gas, for 2.3 MMmtpy.

Kinder Morgan Inc. said in its third-quarter 2018 earnings report in October that the first of 10 small-scale, modular liquefaction units is expected to be placed in service in first-quarter 2019 with the remaining nine units coming online throughout 2019. The total liquefaction capacity of the plant is about 2.5 MMmtpy at a cost of about $2 billion.

LNG Shipping Distances and Costs (Round Trip) from U.S. Gulf Coast to Shanghai, China

Route	Distance (One Way) Nautical Miles	$55,000/day Charter Cost ($/MMBtu)	Fuel Cost - LNG Boil Off at $8/ MMBtu	Canal Costs ($/MMBtu)	Other Costs ($/MMBtu)	Total Costs ($/MMBtu)
Sabine Pass to Shanghai via Panama Canal	10,081	0.78	0.39	0.2	0.14	1.52
Sabine Pass to Shanghai via Cape of Good Hope	15,098	1.18	0.6	N/A	0.17	1.95
Sabine Pass to Shanghai via Suez Canal	13,854	1.08	0.16	0.25	0.16	2.04
Route	**Distance (One Way) Nautical Miles**	**$75,000/day Charter Cost ($/MMBtu)**	**Fuel Cost - LNG Boil Off at $8/ MMBtu**	**Canal Costs ($/MMBtu)**	**Other Costs ($/MMBtu)**	**Total Costs ($/MMBtu)**
Sabine Pass to Shanghai via Panama Canal	10,081	1.07	0.39	0.2	0.15	1.81
Sabine Pass to Shanghai via Cape of Good Hope	15,098	$1.60	$0.60	N/A	$0.18	$2.39
Sabine Pass to Shanghai via Suez Canal	13,854	$1.47	$0.55	$0.25	$0.17	$2.43

Source: Howard Rogers, Oxford Energy Insight, April 2018, "Panama Canal and LNG: Congestion Ahead?

The project is supported by a 20-year contract with Shell. Elba Liquefaction Co. LLC is a joint venture between Kinder Morgan (51%) and EIG Global Energy Partners (49%).

Kinder Morgan has a second LNG project—Gulf LNG—near Pascagoula, Miss. In August, Gulf LNG Liquefaction Co. LLC, Gulf LNG Energy LLC and Gulf LNG Pipeline LLC received a FERC notice of schedule for environmental review. The final environmental impact statement will be completed in April 2019 and the final decision for issuance of the FERC certificate will be in July 2019.

Phase 1 of Gulf LNG will have a single train with a capacity of 5 MMmtpy. Phase II will add a second 5-MMmtpy train.

Lining up reserves

There are two basic business models for U.S. LNG projects. The first, as described by Freeport LNG, is a tolling model. The second is the Cheniere model of a full-service LNG operation offering that includes gas procurement, transportation, liquefaction and shipping.

Qatar Petroleum and Tellurian Inc. are taking a different tack on the gas procurement portion. The Qatari company plans to spend about $4 billion per year for five years in U.S. oil and gas fields, according to *QatarLiving.com*. Some of that gas would likely supply the Golden Pass LNG export project.

Golden Pass Products, a joint venture of Qatar Petroleum and ExxonMobil, will operate the liquefaction facility. Golden Pass is fully permitted for LNG exports and is awaiting an FID. The project involves three trains, each with a capacity of 5.2 MMmtpy.

Tellurian is developing the Driftwood LNG project near Lake Charles, La. In a November 2017 press release announcing the closure of the acquisition of 9,200 acres in the Haynesville shale for $85.1 million, Meg Gentle, Tellurian president and CEO, said, "Acquisition of natural gas producing acreage in the core of the Haynesville provides the foundation for a growing portfolio of assets that we expect can produce LNG for a cost of $3/MMBtu, free on board U.S. Gulf Coast.

While U.S. companies continue to position themselves in the market, competition in the rest of the world is doing the same.

Canada enters the fray

The newest FID was taken by Shell Canada Energy and its joint venture participants for LNG Canada in Kitimat, British Columbia. The facility will consist of two trains with a total capacity of 14 MMmtpy with the potential to add two trains, according to an October Shell press release. Construction will begin immediately with JGC/Fluor as the EPC contractor.

With access to abundant, low-cost Canadian gas, the project has an additional benefit in that it is 50% shorter than the route from the Gulf of Mexico. TransCanada will build, own and operate the 402-mile Coastal GasLink Pipeline from the British Columbia fields to the plant. The project has a 40-year export license.

Dominion Energy's Cove Point, Md., facility is the second plant in the U.S. to be exporting LNG. It entered service in April of this year. *Source: Dominion Energy Cove Point*

LNG Canada is expected to deliver Shell an integrated internal rate of return of some 13% with a significant cash flow at a gas price of $8.50/MMBtu delivered in Tokyo Bay. Total Western Canada gas resource has an estimated 300 Tcf at a cost below $3/MMBtu. Shell's working interest in British Columbia's Groundbirch production project is assessed to hold over 9 Tcf of recoverable resources with a cost of supply of around $2/MMBtu, explained Martin Wetselaar, integrated gas and new energies director for Royal Dutch Shell, in an October webcast.

"When compared to a typical greenfield development on the Gulf Coast, we expect LNG Canada to benefit, on average, from lower shipping costs of $1/MMBtu. In terms of the gas supply—including the cost of the pipeline—we expect to see on average a $0.50/MMBtu advantage," said Jessica Uhl, Royal Dutch Shell CFO.

Swimming with sharks

Cheniere is leading the charge into international LNG markets with its Sabine Pass and Corpus Christi liquefaction plants. However, they are not the only sharks in the LNG ocean. The competition is reading the same price forecasts and supply demand curves.

Currently, Qatar is the leading LNG producer worldwide with 77 MMmtpy of capacity. With the addition of the Prelude and Ichthys LNG plants offshore Australia, that country will be new world leader with nameplate capacity of about 85 MMmtpy.

The U.S. is vying to be in the top three of LNG producers.

However, Qatar doesn't want to relinquish its title as the world's leading producer. The country announced it would build four new 8-MMmtpy LNG trains, which would increase its production to over 110 MMmtpy and return it to the No. 1 spot.

The company has been positioning itself for the coming competition for customers. As of last January, all of the ventures previously operated by Qatargas and RasGas are now operated by the "new" Qatargas, according to a Qatar Petroleum press release.

Qatargas announced in September, a 22-year sale and purchase agreement (SPA) was signed with PetroChina International Co. Ltd. for 3.4 MMmtpy. LNG delivery was set to begin in September 2018. The SPA will be supplied from Qatargas 2, a joint venture between Qatar Petroleum, ExxonMobil and Total.

This is part of a concerted effort by ExxonMobil to tap into the rapidly increasing Chinese LNG market. In addition to its Qatari project, the company has a 20% interest in Gorgon LNG in Australia as well as interests in a three-train (8-MMmtpy) expansion of Papua New Guinea LNG, and 3.4-MMmtpy Coral Floating LNG offshore and the 7.6-MMmtpy Rovuma LNG onshore Mozambique. Asia and Europe are the targets for all of those projects.

Anadarko's plans

Anadarko Petroleum Corp. is working on signing SPAs to secure financing for its initial Mozambique two-train, 12 MMmtpy facility. In June, Anadarko announced signing an HOA with Tokyo Gas and Centrica LNG Co. Ltd. for 2.6 MMmtpy from startup to the early 2040s. In March, an SPA was signed with Électricité de France SA for 1.2 MMmtpy for 15 years.

"For example, in Mozambique and other countries in the region, there is a significant LNG development that could be in very close proximity to a lot of customers that U.S gas would be vying for," said BDO's Broxson.

Shell and Equinor recommitted to the 10-MMtpy Tanzania LNG project.

Australia hasn't given up either. Woodside and BHP are developing the Scarborough Field to supply gas for the 4 MMmtpy to 5 MMmtpy Pluto Train 2 with an FID expected in 2020.

Nigeria LNG is seeking $7 billion for the 8-MMmtpy addition of Train 7 to its LNG plant, bringing that facility to a total of 30 MMmtpy. An FID is expected this year.

Cross-border natural gas sales are expected to keep some LNG plants at full capacity. For example in August, the government of Trinidad and Tobago signed an agreement to purchase 150 MMcf/d of natural gas from Venezuela's nearby offshore Dragon Field, providing much needed additional feedstock for the Atlantic LNG plant in Point Fortin, Trinidad, noted the U.S. Energy Information Administration.

Egypt has two LNG plants—Damietta LNG and Egyptian LNG—where production was curtailed due to domestic demand for gas. With gas feedstock from ENI's Zohr and Nooros fields offshore Egypt, for example, the country could end imports sooner than first expected and increase the prospects of becoming a net exporter again.

In September, Noble Energy announced it had executed multiple agreements to support delivery of natural gas from the Leviathan and Tamar fields offshore Israel, which could also supply the LNG facilities. Production from Leviathan is scheduled to begin by the end of 2019.

Other projects and resources, such as Sempra Energy's Energia Costa Azul LNG project in Baja California, the Russian Arctic 2 project, the Shtokman Field in the Russian Barents Sea with 130 trillion cubic feet of gas and offshore Africa, are still in the mix for meeting the expected LNG gap.

LNG heads East

Shipping costs from the U.S. Gulf Coast to Asia are among the highest in the world, costing about $2.20/MMBtu. With the opening of the new, expanded Panama Canal about two years ago, the distance to Asia was shortened and shipping costs were lowered to about $1.80/MMBtu, which is the cheapest route to Asia, said McKinsey's Dediu.

"At the moment there is one slot per day for LNG. The projection is that by the end of the next decade there will be a need for about three or four slots per day," he continued. "Generally what we see is the Atlantic Basin being a net exporter into the Pacific Basin. A lot of the cargoes will come from the U.S. Gulf of Mexico."

The Panama Canal Authority introduced new rules in October, allowing two LNG carriers on Gatun Lake at the same time, although moving in opposite directions, and letting carriers travel at night. The number of slots was increased to two and will likely be bumped up to three slots in 2022.

Conventional LNG carriers can transit the canal. Only Qatar's Q-Max and Q-Flex carriers cannot transit.

According to an April report from the Oxford Institute for Energy Studies, "The prospect of the Panama Canal becoming a bottleneck for LNG supply from the Atlantic Basin to Asian markets is a very real possibility."

A single slot per day—with half of those vessels (empty) being return ballast voyages—would equate to 19.2 Bcm of LNG from the U.S. to Asia. Two slots per day would equal 38.3 Bcm, noted the study.

What goes around

The Kenai LNG plant was sold to Andeavor in 2018. Then Andeavor merged with Marathon Petroleum, and Kenai was back with one of its original owners—what goes around, comes around.

Although the Kenai LNG plant is no longer producing LNG, plans for another LNG plant near Kenai are underway. ExxonMobil, BP, ConocoPhillips and TransCanada selected a site in the Nikiski area on the Kenai Peninsula as the lead site for the proposed Alaska LNG project's liquefaction plant and export terminal, according to an October press release.

The project concept includes a gas treatment plant on the North Slope, an 807-mile, 42-inch gas pipeline and at least five off-take points for in-state gas delivery. The plant would have a capacity of 20 MMmtpy. Total cost is estimated at $45 billiion to $65+ billion, acccording to Alaska Gasline Development Corp. (AGDC) and Alaska LNG.

AGDC, Sinopec, CIC Capital Corp. and Bank of China signed an agreement supplementing the joint development agreement signed in November 2017, according to an October press release. AGDC agreed to reserve 15 MMmtpy for Sinopec. In 2017, AGDC signed a memorandum of understanding (MOU) with Korea Gas Corp., an MOU with PetroVietnam Gas and a letter of intent with Tokyo Gas Co. Ltd.

"Alaska is a trusted source of LNG. For more than 40 years Tokyo Gas received shipments of LNG from Alaska. Alaska LNG is naturally an economic and reliable source of LNG for Tokyo Gas," said Michiaki Hirose, Tokyo Gas president in a December press release.

"The Alaska project is much more like a traditional liquefaction project in East Africa, Western Australia, Siberia or the Middle East in that the projects have dedicated reserves, dedicated infrastructure and massive capital costs versus U.S. Gulf projects, which generally feature lower capital cost but higher variable costs," said RBN Energy's McCullagh.

"Compared to Gulf export facilities that are competing with the U.S. market for each Btu, Alaska does have some advantages in terms of its proximity to Asia, but Alaska LNG would pay the same tariff on LNG in China as Gulf Coast LNG. Alaska LNG seems to have more commercial alignment than it did two or three years ago.

"But the size of that project means that it needs to put together a bigger volume of SPAs for it to go ahead," she continued, noting RBN Energy follows the intersection between the U.S. gas market and global LNG markets in its *LNG Voyager* newsletter.

Bernstein's Beveridge emphasized that "Alaska seems an odd project to be pushing from a Chinese point of view. One possibility is the Chinese are focusing on Alaska because they know it is the one least likely to be built. One thing that does make Alaska different than a Lower 48 project is that you could see the project priced on an oil-linked basis rather than Henry Hub, which the Chinese may prefer over the long run.

"This is quite interesting because I think the biggest issue for Chinese buyers in regards to U.S. LNG is that when they are signing up for a typical U.S. LNG project, effectively they are making a commitment for hub pricing for the next 25 years. They're basically locked into that spread between oil-linked prices and Henry Hub through to the mid-2040s," he added.

Over the next 25 years, there is a possibility that prices could change significantly, making U.S. LNG exports not particularly attractive in regards to oil, he speculated. If Henry Hub prices stay low at $2/MMBtu to $3/MMBtu for the next three decades, any hub-linked prices will be the right choice. "But as we all know, in the past Henry Hub has been very volatile." ■

***Scott Weeden** is a Houston-based freelance writer and frequent Hart Energy contributor specializing in energy issues.*


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An oil tanker approaches the Centennial Bridge in the Panama Canal's narrow Culebra Cut. The span carries the Pan-American Highway more than 260 feet above the waterway. *Source: Shutterstock/ Anatoly Menzhiliy*

Have Product, Will Travel

An abundance of supply and a superior refining sector have positioned the U.S. well in the global energy trade. But threats to export success, both foreign and domestic, loom.

By Joseph Markman

At first glance, the strategy for managing the burgeoning oil and gas export market appears to be simple:

- Produce more product than the U.S. market can consume;
- Sell it to buyers elsewhere who need it; and
- Hire a smart accountant to keep track of all the profits that will gush in.

But issues, from foreign and domestic supply/demand imbalances to trade policies, complicate the export environment, speakers at Hart Energy's Midstream Finance conference, held recently in Dallas, told attendees.

To begin, the numbers look good. Even great.

"Gas production is reaching 83 billion cubic feet per day (Bcf/d) by the end of 2018," said Michael W. Hinton, chief strategy and customer officer for Allegro Development Corp. "With that, we currently have a domestic consumption of roughly 81 Bcf/d, so we have a 2 Bcf/d differential that needs to find a new home."

The surplus in NGL is about 1 million barrels per day (MMbbl/d) with growing demand from global customers, particularly in the emerging economies of Asia.

"Even more dramatic than what's happened on the crude side of the equation in the U.S. with the shale boom has been the related change and shift in the refined product trade balance in the U.S. A short time ago, the U.S. was the largest net importer of refined products in the world, peaking at a 2.5 MMbbl/d deficit in 2005. Currently, it's the largest–by most measures–net exporter of refined products in the world."

– **John R. Auers**, *executive vice president, Turner, Mason & Co.*

We're No. 1

The U.S. is the world's No. 1 exporter of NGL, shipping an average of 600,000 barrels per day (Mbbl/d) in first-half 2018 to markets in Asia and Oceania. During that period, Canada and Mexico imported an average of more than 400 Mbbl/d of U.S. NGL.

In Europe, customers are busy building regasification infrastructure to handle imports of U.S. LNG and reduce their dependence on pipelined natural gas from Russia.

"We continue to ramp exports," Hinton said. "U.S. gas plant production is continuing to increase out past 2022. With that, you can see the oncoming infrastructure to support that export activity maximized toward the end of 2018, into 2019."

So the export market is not only a good place for the U.S. oil and gas sector to be, but also a necessary place to be.

"We have limited growth of demand in the domestic market space today," Hinton warned. "That could change if we see companies starting to build plants in the U.S. to take on those NGL to produce other products, but again, limited demand locally points to exporting the NGL. The last wave of infrastructure to come on play is … supporting the export activity."

The U.S.' exporting edge relies on its strength across the oil and gas value chain.

Worst to first

"Even more dramatic than what's happened on the crude side of the equation in the U.S. with the shale boom has been the related change and shift in the refined product trade balance in the U.S.," John R. Auers, executive vice president of Turner, Mason & Co., told attendees. "A short time ago, the U.S. was the largest net importer of refined products in the world, peaking at a 2.5 MMbbl/d deficit in 2005. Currently, it's the largest—by most measures—net exporter of refined products, in the world. It looks like it will continue to grow."

Weak domestic demand forced the U.S. refining sector to pursue export markets. In the last 12 years, Auers said, developing economies have increased their demand for refined products by 18 MMbbl/d. Developed economies reduced their demand by 4 MMbbl/d during that time, even considering the bump in the last three years derived from low prices.

Those growing markets have responded with an infrastructure building spree, he said. In India and China alone, refining capacity has almost doubled in that 12-year period. However, in the developed economies of Europe, Japan and Australia, refinery shutdowns have reduced capacity by about 3.5 MMbbl/d.

Not all developing regions are able to replicate Asia's example, though. Latin America is a case of growing demand where the refining capacity and utilization have not only failed to keep up but have declined. And it's not because the energy sectors in those countries have ignored the need to expand their refining systems. They just can't get it done.

"They've spent a lot of money trying to build and expand capacity," Auers said. "Billions spent, still not completed."

Venezuela, a country immersed in societal upheaval, formerly enjoyed a particularly advantageous position built by its national oil company, PDVSA. But no longer.

"Their refining system has collapsed," he said. "It went from being the best-run nationally controlled oil company to probably the worst-run. They run their refineries at 20% utilization or less and actually have to import product."

Mexico, the single largest destination for U.S. refined product exports, has moved in a different direction.

"They're doing the right thing by moving toward energy reform but … refinery operations have struggled because there is less support for the refining system," Auers said. "The money is flowing more toward product distribution, toward import capabilities, which are easier projects to justify."

The country's president-elect, Andrés Manuel López Obrador, has promised to spend $11 billion to upgrade existing refineries and build a new one, but Auers is skeptical. "We don't think there's a prayer of that happening any time soon. They just don't have the money."

Even completed Middle Eastern facilities experienced difficulties with delays and cost overruns. For example:

- Al-Zour Refinery in Kuwait (completion expected in 2020): $5 billion over budget, seven years late;
- Yanbu Refinery in Saudi Arabia (completed in 2016): $4 billion over budget;
- Jubail Refinery in Saudi Arabia (completed in 2013): $6 billion over budget; and
- Jazan Refinery in Saudi Arabia (completed in 2017): $2 billion over budget; two to three years late.

Enter the downstream

Enter the U.S. downstream sector. This world-beater has shown itself to be particularly adept at rising to the challenge of remaining competitive where others have struggled.

"The U.S. refining industry has developed into one of the most competitive refining industries in the world," Auers said. "A lot of it has been underpinned by the free market environment which we operate in. That's not the case in many other areas. Despite what it seems like sometimes, even this election season, we have a fairly stable political environment and economic environment."

Equipment upgrades have made refineries bigger, more efficient and more capable. Complex U.S. refineries can handle harder-to-process crudes, including heavy, sour crude, and turn them into higher-yield products. U.S. facilities boast higher utilization rates on a more reliable basis than refinery systems anywhere else in the world. The industry has accomplished this despite comparatively high wage rates and is able to operate refineries much more efficiently than in other countries.

With all these advantages piled up in the U.S. corner, why worry? Among the challenges: taking care of the world's supply/demand balance begins at home.

U.S. supply capacity is stressed to meet local demands, Hinton said, pointing to the natural gas situation on the East Coast. There is limited capacity to deliver gas into areas such as New England by pipeline. While most of the country has taken advantage of lower natural gas prices because of supply and infrastructure, the East Coast has been vulnerable to price spikes for several reasons.

"The East Coast is continuing to rely more heavily on a single fuel [natural gas] for the producing of power, so it's creating additional demand along with the domestic demand," he said. Extreme weather events such as winter storms, combined with population growth have resulted in extreme price volatility.

"We continue to ramp exports. U.S. gas plant production is continuing to increase out past 2022. With that, you can see the oncoming infrastructure to support that export activity maximized toward the end of 2018, into 2019."

– **Michael W. Hinton**, *chief strategy and customer officer, Allegro Development Corp.*

Will the East Coast constraint issues escalate as the U.S. becomes more exposed to the global market?

"That I don't know," Hinton admitted, "but I know that as we continue to increase the demand for our products. It's going to introduce volatility."

And that volatility will not be restricted to a single link in the value chain. As demand seesaws and takes prices along with it, producers of commodities, as well as those who transport and process them, can be affected. The volatility could also influence exposure to counterparties. Anyone doing business with a player affected by extreme price swings will feel the impact. Include infrastructure investors in that category. How much is enough? How much is too much? Miscalculations could result in underutilized and less-profitable, or unprofitable, facilities.

Auers pointed to the risk of a growing dependency on export markets. Saturation in traditional markets could force exporters to pursue new markets where the U.S. has fewer advantages and more competition. There remains the risk that other countries will attempt to develop their own refining sectors, which could result in global overbuilding. Escalating trade tensions, particularly with China, also could dampen worldwide demand.

"How do we navigate that uncertainty?" Hinton asked. "That's really the key." ■

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Cheers!

Not all U.S. natural gas exports leave as liquids. The nation's next-door neighbors offer expanding, but challenging, markets via the North American gas transmission grid.

By Paul Hart

Mexico's expanding industrial base, from breweries to power plants, increasingly relies on natural gas exports from the U.S. *Source: Shutterstock/ NaturalBox*

Americans love Mexican beer. Much of that beer consumed by *los norteamericanos* at tailgates, parties, wedding receptions, happy hours and elsewhere bubbles to life at one of the world's largest breweries—the sprawling Compañía Cervecera de Coahuila plant—on the outskirts of Piedras Negras, Mexico.

Piedras Negras and Eagle Pass, Texas, are twin cities that lie either side of the Rio Grande. It takes lots of natural gas to run a modern brewery and the plant, owned by Constellation Brands, has an advantage over competitors. It's located at the western end of Texas' big Eagle Ford Shale play.

American gas exports make for Mexican beer imports.

Mexico would like a lot more U.S.-produced gas, but demand for gas across the border hasn't grown as fast as many in the midstream expected; the nation has other demands.

'Topsy turvy'

RBN Energy termed Mexico's natural gas market "topsy turvy" in a year-end 2017 report that predicted demand will rise this year and beyond as Mexico replaces fuel oil and coal in its power plants with gas. Meanwhile, Mexico's domestic gas production continues dropping as the nation pushes lucrative crude oil production and exports.

A growing volume of the gas flowing from the Eagle Ford, the Permian Basin and other plays flows south under the river to auto assembly plants, bakeries, power plants and breweries as Mexico strives to industrialize.

Any significant uptick in U.S. gas sales to Mexico "will be tied in large part to how quickly new gas pipeline capacity can be completed within Mexico, but a number of pipeline projects south of the border have experienced delays," RBN added.

But the uptick is happening more slowly than the industry had hoped.

"If you go back four or five years ago, people thought that we would be close to 6 billion cubic feet per day (Bcf/d) of net exports to Mexico today," Leigh R. Goehring, managing partner at Goehring & Rozencwajg Associates LLC, told *Midstream Business*. "But I think where we are today is about 4 Bcf/d to 5 Bcf/d, according to EIA [U.S. Energy Information Administration] data. I don't know what the real reason is for the lack of robust growth. Is it because of what's happening in the Mexican economy, they're using less gas? Or is it just that their pipeline infrastructure is not actually developing?"

An additional 4 Bcf/d is nothing to ignore, but it's not why midstream started putting pipe in the ground to serve the Mexican market.

Indeed, sales across the border improved as 2018 went along, RBN Energy noted in a third-quarter 2018 report. It said sales passed 5 Bcf/d in the second half of the year "and have hung on to that level since. This new export volume signifies incremental demand for the U.S. gas market at a time when the domestic storage inventory is already approaching the five-year low," the report said. "At the same time, it would also signify some much-needed relief for Permian producers hoping to avert disastrous takeaway constraints—that is, if the export growth is happening where it's needed the most, from West Texas. However, that's not exactly the case."

Waha woes

The booming Permian Basin has the most to gain from Mexico, the closest substantial market to West Texas and southeastern New Mexico. New wells in the play's Delaware Basin are gassy, and that associated gas has to go somewhere even if producers drill for the more lucrative oil. Right now, there's a scramble to move Permian gas south, east—anywhere.

"Effective Permian natural gas takeaway capacity is completely utilized, keeping Waha basis under pressure," Baird Equity Research said in a third-quarter analysis. "Though we estimate nameplate West Texas gas takeaway utilization currently stands at 88%, we believe effective takeaway utilization is closer to 120%. The three operational Mexican export pipelines, ONEOK's Roadrunner and Energy Transfer's Comanche Trail and Trans-Pecos, brought online an aggregate 3.1 Bcf/d in design capacity.

"Actual flows, however, are constrained to just roughly 0.3 Bcf/d at present, the limit of Mexico's current import infrastructure. Nonetheless, this level is a material improvement from the sub-0.2 Bcf/d for most of first-half 2018," it added.

Last summer's startup of TransCanada's 670 million cubic feet per day (MMcf/d) Topolobampo Pipeline in northwest Mexico helped, bringing a modest improvement in Permian gas prices. But Waha was still trading at nearly $1.80 per million British thermal units below the benchmark Henry Hub price in November.

"Beyond exports to Mexico, we believe the gas production trajectory will require two of the six proposed greenfield takeaway projects at a minimum" to bring the Permian into line, Baird added in its report.

Something short-term

"Those three main pipelines that are coming out of the Permian to Mexico have been ready to go and capacity has been there for a while, but the

Mexico's rugged interior makes pipeline construction difficult. A worker prepares a push rack during construction of TransCanada's 230-mile natural gas Tamazunchale Pipeline extension. *Source: TransCanada Corp.*

Mexican side is not actually taking it," Trisha Curtis, president and co-founder of Denver-based consulting firm PetroNerds LLC, told *Midstream Business*. "The Permian needs some short-term alleviation that people are expecting for the gas side."

That could come via the Gulf Coast Express (GCX) project scheduled to enter service in late 2019.

The line is a joint venture of Kinder Morgan Inc., DCP Midstream LP and Targa Resources Corp. Announced it late 2017, it would move 220,000 dekatherms per day (Dth/d) of gas from Waha to the South Texas Agua Dulce hub—and from there to either Mexico or the Texas Gulf Coast petrochemical market. Construction started in May.

Along with 160,000 Dth/d of available capacity, 60,000 Dth/d were added due to strong market demand. With the added capacity, the total GCX Project will have a total design capacity of 1.98 billion cubic feet per day (Bcf/d) at an estimated cost of $1.75 billion.

Occidental Energy Marketing Inc., a subsidiary of Occidental Petroleum Corp., and Kaiser-Francis Oil Co. are among producers buying firm capacity.

GCX might not be enough. In August, Targa announced plans for the Whistler Pipeline, a 2 Bcf/d gas line, also from Waha to Agua Dulce. Partners are NextEra Energy Pipeline Holdings LLC, WhiteWater Midstream LLC, and Marathon Petroleum's MPLX LP. The parties are committing roughly1.5 Bcf/d to the project, which is expected in-service by fourth-quarter 2020 pending regulatory approvals. NextEra Energy Pipeline Holdings will construct the project, while Targa will be the operator.

Big tickets

Both lines are big-ticket projects, stretching more than 400 miles and costing about $2 billion each. And there's still the potential problem for capacity or demand limits across the border. But Agua Dulce is "definitely better" than Waha right now, according to Goehring.

"The Eagle Ford has that ability to go east where all those big LNG plants, next year, are going, creating 5 Bcf/d to 5.5 Bcf/d of new gas demand," he added. "That's going to pull that Eagle Ford gas due east. They don't have the tremendous problem that they do in West Texas, where producers are temporarily trapped.

"Their big problem [in the Permian] is whether they can physically get the gas out. They don't care whether they basically receive almost zero for it," he added. "So as long as there's enough capacity to get it out, I think they're OK with the prices because the gas is a byproduct."

Whether the problem south of the border is demand or capacity is hard to determine, Curtis added.

"The problem is most definitely on the other side of the border," she said. "I think the problem is they don't have the infrastructure on the other side. But you don't get a whole lot of clarity because they don't have a lot of transparency.

Even when you're talking to experts on the Mexican side, they still don't know the details of all the pipelines—and that's a big one."

Part of Mexico's infrastructure problem stems from permitting, which is a headache familiar to U.S. midstream operators.

"It's interesting how some of these countries further south, like Colombia, have a very strong green movement that definitely enforces all sorts of regulations," Goehring said. Mexico's significant energy reforms, begun in 2013, have added confusion over which parts of the energy sector do certain tasks. According to a May *Reuters* article, upstream firms that won drilling blocks encountered red tape that has slowed drilling and development. The same holds true in the midstream, many industry analysts maintain.

And the problem may get worse as leftist politician Andrés Manuel López Obrador is sworn in as Mexico's new president. López bitterly criticized the energy reforms but struck a more moderate tone during the transition period leading up to his inauguration on Dec. 1.

"Even when you're talking to experts on the Mexican side, they still don't know the details of all the pipelines–and that's a big one."

– **Trisha Curtis**, *president and co-founder, PetroNerds LLC*

Canadian confusion

The gas market north of the border also suffers from confusion, although gas has moved freely in both directions for decades. "Canada pursues similar energy policies to the U.S., which currently buys 90% to 99% of Canadian oil and gas. This means technology development in Canada must address business, technical and regulatory requirements and economics in both markets," DNV noted in its "Energy Transition Outlook 2018" study, published in late September.

Canadian gas prices "have just been terribly depressed," Goehring said. "But what's so interesting about that is that even with depressed gas prices, the Canadian gas players are making money."

A long-sought Pacific LNG export operation—LNG Canada—may come to fruition as Shell and its partners announced plans to move ahead with a project based at Kitimat, British Columbia, 400 miles north of Vancouver. It could sell significant volumes of gas to Asia. The seaport in northern British Columbia would enjoy the shortest trans-Pacific route to China, South Korea and Japan—half the distance from the U.S. Gulf Coast and without pricey Panama Canal tolls. But the seaport is remote and would require building hundreds of miles of pipeline from Dawson Creek, British Columbia, across the heavily forested Rockies.

The project has customer support. Tokyo Gas announced in October a 13-year agreement to take 14 million tonnes per annum from the project.

IP would draw about 1.8 Bcf/d of gas, but the plant would not go onstream until 2022 at the earliest. RBN noted in a late-October report that the project "won't come online until 2023—an eternity for producers in the region's Montney and Duvernay shale plays, who through much of 2018 have endured profit-crushing price discounts for their gas relative to Henry Hub."

It would be a big ticket: Cost would be CA$40 billion (US$31 billion).

Canada, like the U.S., has excellent midstream infrastructure but needs to add connectivity between producers and new markets. This compressor station is on TransCanada's Foothills Pipeline, which serves producers in Alberta and Saskatchewan. *Source: TransCanada Corp.*

The port city of Kitimat, British Columbia. If built, its liquefaction plant will have a significant advantage over U.S. Gulf Coast LNG competitors due to the port's proximity to major Asian customers. *Source: District of Kitimat*

If—and when—Kitimat goes onstream, it will help redraw North America's gas flow map, RBN added. "The challenges that [western Canadian] producers have faced in the intervening years as production growth in the Marcellus/Utica, the Permian and other U.S. plays squeezed them out of their traditional markets (the Northeast, the Midwest, Eastern Canada, etc.)" are major, it said.

Indeed, "The Montney is an impressive play and has tremendous potential," Goehring noted.

The proposal has drawn bitter opposition from British Columbia's government and environmental groups. But if the project comes off—and that remains *if*—it will not impact North American gas demand for years, Goehring said. Two proposed LNG facilities in Quebec are also in consideration, "but again, we're talking years and years to go," he added, "a minimum of 2025 or something like that." If built, they would create a new market for Marcellus and Utica gas.

And it may not happen even with the current support, Curtis cautioned. "If they're getting that built, that would be really positive for potentially moving gas up through the Northwest. Any North American LNG exports I think are positive. I don't think that hurts the U.S. in any capacity because they probably would just open up avenues for more U.S. gas to get into Canada."

"I would hope that we would be able to expand natural gas exports to Canada, probably through existing systems we have that cross the border from the Northeast," Curtis said. "But if we really think of where we put this natural gas, and if we have a slow build for LNG exports—and particularly if we have issues with sending those exports to China—we really need to be pushing into Canada.

"I think the problem is when you look at the slated capacity for LNG, and you look at the exports, it's a slow ramp-up and it's not going to be the savior everybody's thinking," she added. "I would assume that's as it should be, But it doesn't mean that's actually going to happen, but it should be something thought about pretty seriously. I do think there are serious ramifications for things going on with China, which could in fact be the export market for both crude products and LNG." ■

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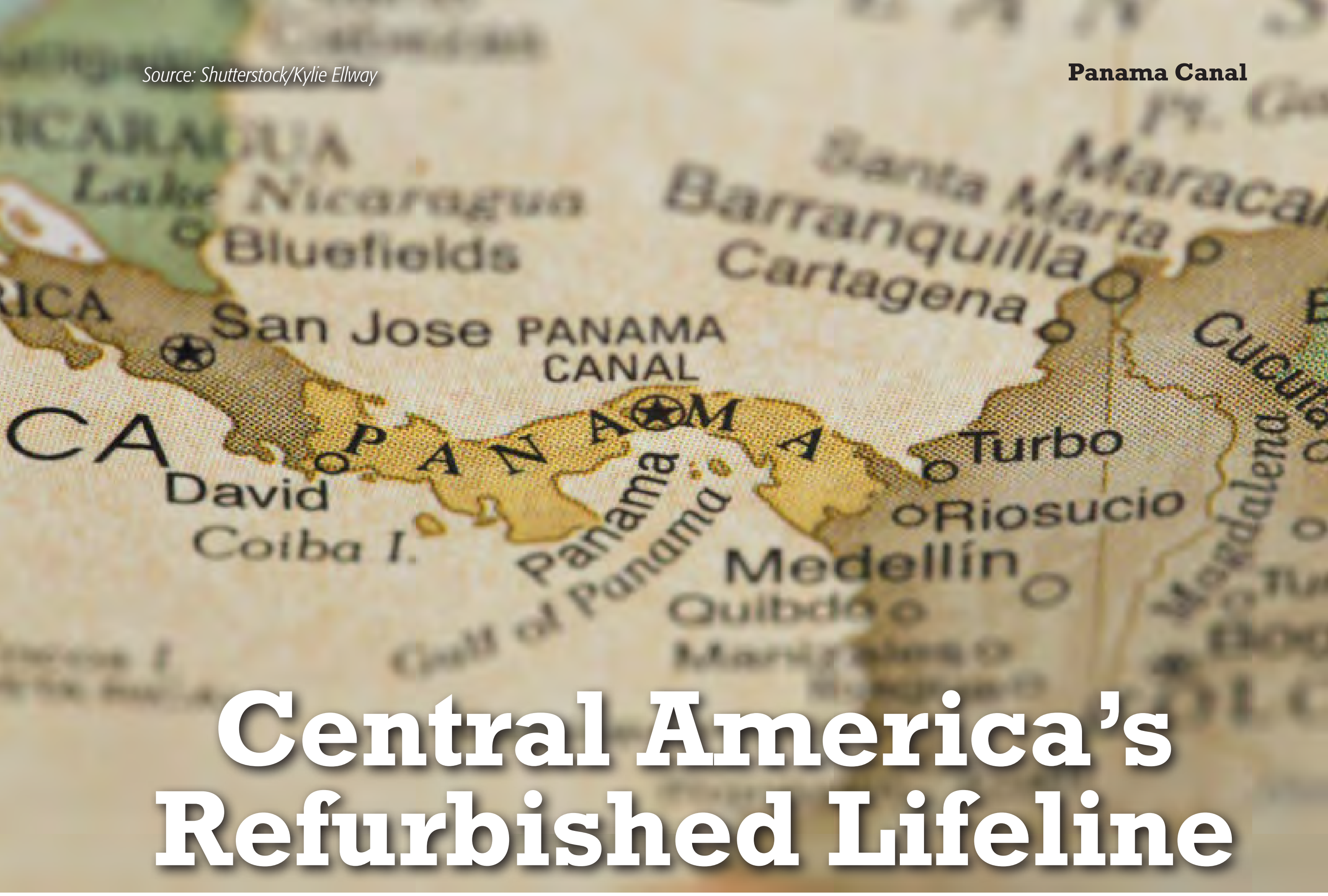
Water is a
Big Deal



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Central America's Refurbished Lifeline

The recently expanded Panama Canal provides an essential connection for LNG and other energy exports.

By Garland L. Thompson

Questions have been raised about the newly enlarged Panama Canal's ability to handle all the LNG shipments U.S. producers are gearing up for. How will the canal's huge, new third set of locks handle all the traffic? With Corpus Christi, Texas, two other U.S. Gulf Coast terminals expect to join Cheniere Energy Inc.'s Sabine Pass, La., facility loading tankers. Dominion Energy Inc.'s Cove Point, Md., plant on Chesapeake Bay is adding still more, and Kinder Morgan Inc.'s Elba Island, Ga., terminal is on the way.

Panama Canal Authority chief administrator Jorge Luis Quijano has an upbeat answer. On a May trip to Asia, he told surprised import officials that the new traffic posed no problem. Panama expects LNG shipments across the canal to grow to 5x the current levels by 2020. Despite being the Panama Canal's fastest-growing traffic segment, LNG vessels currently use only 60% of the reservations they acquire, Quijano said in an August statement. That's with the authority's count of gas shipments already filling nearly 40% of the 4,000 NeoPanamax vessels that have sailed through the canal's big new locks between the expansion project's June 2016 opening and July 30, 2018. Some 27% of those ships transiting were LPG tankers, while LNG transits—10% of the total to date—are ramping up.

Container ships account for 52% of canal traffic, while dry and bulk carriers, car carriers and cruise ships make up the rest, the authority reports.

LNG ramp-up

Quijano's boast seems believable since Panama has not only expanded its canal, but it has made the waterway a two-way avenue. The original century-old system permitted ship transits only one way at a time, but in 2016, canal authority personnel told this writer they'd begun training canal pilots, merchant captains and tugboat operators to handle "meeting engagements" between vessels going in opposite directions.

So in addition to adding parallel, deeper channels between the new locks, Panama made way for even more traffic, and it is paying off.

On Oct. 1, Panama officials announced that four LNG tankers transited the canal's larger locks on the same day. The Bahamas-flagged *Torben Spirit*, capacity 174,000 cubic meters (cu.m); and Marshall Islands-flagged *Oceanic Breeze,* capacity 155,000 cu.m, headed south to the Pacific. The Norway-flagged *Ribera del Duero Knutsen*, capacity 173,000 cu.m, and Greek-flagged *Maran Gas Pericles*, capacity 174,000 cu.m, went north to the Atlantic.

Dominion's Cove Point shipped its first LNG load through the canal on May 1, the first one fulfilling a long-term Sumitomo Bank and Tokyo Electric contract for Japan's power producers.

More multi-vessel transits could happen because of dredging the canal's new channels deeper—60 feet (ft) against the old locks' 40 ft; 180 ft wide compared with slightly more than 100 ft; and 1,400 ft long compared with the old locks' 1,000 ft. To get the best preparation, the authority sent canal pilots, tug captains and cargo ship skippers to France's Port Revel Training Facility.

There, ship-drivers practiced real-time maneuvers in a lagoon built to mimic dimensions of the Panama Canal and Gatun Lake during construction of the new locks. Later, in the canal authority's own smaller replica of France's facility, they communicated by radio—just like on ships' bridges—training on 1/25th-scale-model ships and tugs operated by onboard instructors, canal pilots and merchant ship captains. Trainees learned to handle ship "encounters" and maneuver through the enlarged canal.

In regular operations, two-way meetings now happen in Gatun Lake, which provides water to power the locks' operation as it supplies hydroelectric power and potable water for Panama, in addition to serving as the waterway's central passage.

Safely opening the way

As the fourth quarter began, the authority also relaxed certain daylight travel and meeting restrictions on LNG tankers, responding to the demands of shippers and reflecting canal personnel's improving experience handling the tanker transits. The authority has made space for two LNG tanker reservations per day. Notably, the authority reports capacity for up to two more ship-transits per day through the new locks,

The Singapore-flagged LNG carrier *Galea* inches through one of the Panama Canal's new locks. *Source: Panama Canal Authority*

in addition to the 5.5 transits per day it now averages.

"We are fully committed to understanding and meeting the ever-changing needs of the global shipping community. These changes, guided by input from our customers, strategic planning and years of experience, are an essential next step in assuring the continued availability of the expanded canal for all," Quijano said in a statement.

With new experience, canal pilots, tug captains and lock-side personnel have refined their ship-handling techniques for safety.

When a ship transits the existing, century-old Panama Canal, it gets hooked by steel cables to four electric locomotives, two up front on each side and two at the rear. But the big NeoPanamax vessels are towed by 100 ft long tugs instead. Earlier, canal pilots, tug captains and the Society of Panamanian Engineers complained that this arrangement was less safe, opening the way for uncontrollable ship movements in times of high winds.

A long story by *The New York Times*, published just as the expansion project was completed, detailed those worries.

Where they belong

Today, however, an authority news release details the best practices canal personnel have worked out.

Instead of the old canal policy of one tug following a ship through the canal, ships transiting the new locks use four tugs to move them into the first set encountered, Agua Clara on Panama's Atlantic side, and Cocoli on the southern, Pacific side. One tows at the bow, one each port and starboard, and one is tied to the ship's stern, to maintain positive steerageway. Once the ship is in the

A ship leaves the Agua Clara locks, part of the expansion of the Panama Canal that has greatly increased capacity for U.S. exports leaving the Gulf of Mexico. *Source: Shutterstock/Halfofmoon* lock's entry channel, the side-guiding tugs move off but the towing and tailing tugs stay with it.

Inside a lock, ground-side line crews tie cables from the ship's sides to bollards set into the locks' reinforced-concrete sides, preventing excess lateral motion. The line-setting and releasing continues as the ship moves through the lock sets. The ship crosses Gatun Lake under its own power, accompanied by tugs.

As with the existing locks, no vessel transits the Panama Canal without tugboats close by, watchful against untoward incidents such as a loss of power that might run the ship aground. The Culebra Cut is the canal's narrowest channel through a mountain range, so there are no exceptions.

Just a fit: Four vessels stairstep their way into the Panama Canal via the Gatun Locks on the Atlantic side of the passage. *Source: Shutterstock/BlackMac*

Welcome windfall

The U.S. shale revolution caught the authority's leaders off guard. They decided to expand the cross-Isthmus waterway after watching their Suez Canal competitors complete an expansion, and they meant to keep up, José Ramon Arango, a canal authority senior bulk liquids segment specialist, said when interviewed during the project's opening ceremonies.

Especially the U.S.-sourced LPG shipments, Arango said. Underscoring his point, the second ship to steam through the canal's expanded Cocoli locks on its way to the Pacific Rim was the Japanese-owned *Lycaste Peace* LPG tanker, headed out from the U.S. Gulf Coast.

It may surprise other observers now that U.S. shippers are not the only ones energized by the Panama Canal's enlargement. According to the authority newsletter, *The Canal Connection*, Peru has sent 575,529 tons of LNG through the canal to European destinations in fiscal year 2018. Trinidad and Tobago, the Caribbean's largest exporter, transited 1,340,396 tons to Asia, Mexico's west coast and Chile. Together, the newsletter said, the two nations account for nearly one-fifth of all LNG transits.

Saving days and miles

It's all economics: An LNG tanker leaving Trinidad for Chile saves more than six days using the Panama Canal instead of sailing around South America, while ships leaving Peru for Spain save up to eight days.

On the import side, since the NeoPanamx locks' opening, Mexico has imported an estimated 3.1 million tons of LNG, while Chile has imported some 1.1 million tons.

Across the Pacific, South Korea and China became top importing nations in FY 2018, with Korea taking 1.7 million tons and China taking 1.6 million tons, according to Canal Authority's newsletter. And according to a *Bloomberg* report published months after the Expanded Panama Canal went into business, LNG already had become the world's second-most traded commodity after oil in 2015, before the Panama Canal's expansion project was finished.

Gas is expected to challenge coal at European power plants and become affordable in emerging markets, the *Bloomberg* report said, quoting the International Energy Agency and Goldman Sachs Group Inc.

Americans change the game

That report said that U.S. shale gas, adding to a global glut triggered by new Australian gas output and weakening Asian consumption, is having an outsized impact on how LNG is sold, prompting spot trading in lieu of long-term contracts. *Bloomberg* noted that, with supplies growing, some Asian nations like Japan are contracted to buy more LNG than they can consume, leaving surpluses to be sold elsewhere.

"The U.S. clearly changed the picture," Costanza Jacazio, a senior gas analyst at the Paris-based IEA, said in that report. "It's going basically from zero to the third-largest LNG capacity-holder in the space of five years, and it brings a new flexibility to the LNG market."

But don't forget the oil markets.

The U.S. Energy Information Administration's most recent estimate is that American petroleum exports are minimal compared to surging natural gas exports. But, as Arango noted in that 2016 interview, American shale oil, flowing from Texas' Eagle Ford fields and the burgeoning Permian Basin plays, is low-sulfur light oil, whose specific gravity could permit transiting even a fully loaded Suezmax tanker through the expanded Panama Canal.

With the new Dakota Access Pipeline pouring Bakken petroleum down to the Gulf Coast, and with new transmission lines snaking out from West Texas and eastern New Mexico to reach Corpus Christi—and with that city's leader's recent investments to deepen their already-busy oil port and their recent experiments to train local port personnel to handle very large crude carriers—there's more to come.

U.S. petroleum exports, reaching the world through the expanded Panama Canal, are soon bound to change some other games in energy. ■

***Garland L. Thompson** is a Philadelphia-based writer and editor covering engineering and technology issues. He has covered the Panama Canal extensively.*

The tanker *Stena Suède* rides high in the water as it returns to port for another load of crude oil. Built at Samsung's Geoje, South Korea, shipyard, the vessel entered service in 2011. *Source: Stena Bulk*

The Rush For Export Infrastructure

Getting oil from shale to shore means multiple new terminals and loading facilities will be needed.

By Gregory DL Morris

"We have to take seriously the volume of crude that the U.S. has got to export," Dan Lippe, principal of Petral Consulting, told *Midstream Business*. "Predominantly that is now light sweet crudes, but over time it will be whatever the domestic refining sector does not want."

It is simple economics, Chris Hedge, a director in the process and technology practice at consultancy Opportune, told *Midstream Business*. "We have more supply in the U.S. than we have demand. Without access to more demand, growth is capped. Exports provide access to more demand and supply can grow. Add to this the fact that U.S. supply is low-cost compared with other areas of supply, and U.S. barrels will compete nicely in the global markets."

Not only are crude exports now necessary, the industry already saw the same thing happen on a smaller scale a few years ago.

"This has already happened in propane and NGL," said Greg Haas, director of integrated energy for Stratas Advisors, a Hart Energy company. "If there had not been export approvals for NGL and sufficient pipelines and loading facilities for them as well, we would

"Domestic crudes are trading at a substantial discount to Brent and domestic gas is trading at a substantial discount to global benchmarks as well. U.S. refined products are at a premium, which explains high exports and record U.S. refinery operating rates. It makes all the sense in the world to refine discounted crude to make fuels that sell on the international markets at Brent-based prices."

– **Greg Haas**, *director of integrated energy, Stratas Advisors*

not have seen the shale gale that we did see," Haas told *Midstream Business*. "Millions of barrels of liquids cannot just go into storage without affecting domestic prices and production and, by extension, the international markets."

Exact numbers vary, but there is consensus that U.S. crude exports have been rising steadily since the 40-year ban on most exports was lifted in December 2015. Crude exports averaged 590,000 barrels per day (Mbbl/d) in 2016, 1.1 million barrels per day (MMbbl/d) in 2017, and more than 1.9 MMbbl/d so far in 2018.

Exports hit an all-time high of 3 MMbbl/d in June.

"Those numbers are fairly in line," John Coleman, senior analyst for North American crude markets at Wood Mackenzie, told *Midstream Business*. "It is important to note the 3 MMbbl/d number was one weekly estimate by the U.S. Energy Information Administration (EIA) and subject to cargo timings. I should note the monthly average for June was closer to 2 MMbbl/d. Our outlook going forward is for U.S. exports to continue growing and to more than double before reaching a peak in the 2030s at more than 4.5 MMbbl/d."

According to Opportune, U.S. crude exports have grown 5% per month on average compound monthly growth rate since January 2016, and have increased to 8.1% from January through August 2018.

"If—and it's a big if—that trend were to continue," Hedge said, "it is feasible that we could hit the 3 MMbbl/d monthly average mark by year-end 2018. That would mean loading one more very large crude carrier (VLCC) at 2 MMbbl about every 2.5 days, or approximately 12 more per month. The other option would be 800 Mbbl/d moved through pipelines to Canada or Mexico, or some combination of those options. Based upon my assessment, a sustainable rate of about 2.4 MMbbl/d by year end is more realistic."

Refining, rising

Haas at Stratas is sanguine about consumption rising domestically, which will take some of the edge off the heavy export needs both volumetrically and economically.

"Domestic crudes are trading at a substantial discount to Brent," he noted, "and domestic gas is trading at a substantial discount to global benchmarks as well. U.S. refined products are at a premium, which explains high exports and record U.S. refinery operating rates. It makes all the sense in the world to refine discounted crude to make fuels that sell on the international markets at Brent-based prices."

Lippe at Petral noted that "in just a few years the two biggest refineries in Corpus Christi [Texas] had their crude towers rebuilt to be able to process the increasing supply of light sweet crude from the Eagle Ford. Within three to five years, more majors will retrofit some of their large refineries."

The issue for U.S. refiners is more around crude quality and the light sweet crude being produced in the U.S., Coleman said. "With U.S. refiners close to being maxed out on light sweet crude, it is true that the global market is now required to balance U.S. production. For U.S. production to continue to grow, export markets will be required to absorb nearly all production growth."

Current U.S. refining capacity is 18.6 MMbbl/d, according to the American Fuel & Petrochemical Manufacturers trade association. Of that, 45%, or 8.4 MMbbl/d, are around the Gulf Coast. Stratas expects that something close to an additional 1 MMbbl/d of additional refining capacity can be expected in the next several years.

"ExxonMobil has been talking about increasing crude capacity at its refinery at Beaumont, Texas, since its first-quarter earnings call," said Haas. "That could mean adding something like 400 Mbbl/d to 600 Mbbl/d of crude capacity, which could make the facility the largest refinery in North America."

ExxonMobil's Beaumont, Texas, refinery has a current capacity of about 360 Mbbl/d. The largest in North America is just down the road, at Port Arthur, Texas. That Motiva-owned monster can process 635 Mbbl/d.

In a small irony, the next-largest tranche of additional capacity may come from the facility that once was the largest refinery serving North America. At one time the Hovensa complex at Limetree Bay on St. Croix, U.S. Virgin Islands (USVI), was No. 1 at 650 Mbbl/d—bigger than Motiva Port Arthur today. It was a joint venture of Hess Corp. and Venezuela's PDVSA but was shuttered in 2012. It has since been owned by an ArcLight Capital Partners portfolio company that has operated it as a terminal.

"That is likely to be restarted with a crude consumption of about 200 Mbbl/d to 300 Mbbl/d," Haas said. "Even without any other major announcements of refinery expansions, we anticipate incremental creep of 10 Mbbl/d, 20 Mbbl/d or 50 Mbbl/d at multiple facilities.

"There are also the topping plants that have already popped up in a few shale basins and are likely to continue being built as boutique refineries to meet local demand. All of that could be as much as 200 Mbbl/d. Those, with Hovensa and Exxon, easily get to 1 MMbbl of expanded North American crude refining capacity," Haas added.

Haas also noted a singular attribute at Hovensa, highly relevant to export markets.

No Jones Act

"The U.S. Virgin Islands are, of course, U.S. territory, but they are specifically exempt from the Jones Act." Formally the Merchant Marine Act of 1920, it stipulates that trade between U.S. ports can only be conducted by vessels built in the U.S., owned by U.S. companies, and with an American crew. Many countries have similar cabotage rules, but the dearth of compliant vessels for the coastwise trade makes the Jones Act expensive for U.S. shippers.

"The exemption means that vessels of any nation can take U.S. crude from U.S. ports to the refinery at St. Croix," Haas said. "The same is true of fuels going from a restarted USVI refinery perhaps back to the mainland U.S. This exemption will save several dollars per barrel on crude and on refined products."

The exemption is not a secret. Indeed, BP Plc is thought to be a possible partner in the Hovensa restart. That would make sense, in the context of the company increasing its activity in the Gulf of Mexico. Despite the Macondo disaster in 2010 that killed 11 people, BP still operates four platforms in the Gulf: Thunder Horse, Atlantis, Mad Dog and Na Kika, and has two other large projects underway.

The closest markets

Exports to neighboring nations should not be ignored; Haas noted that Mexico is interested in buying some volumes, most recently of Louisiana Light Sweet grade, and also that Canada imports significant volumes of condensate. Most of that is used as diluent for bitumen. The resulting "dilbit"' blend flows easily through pipelines, or in and out of general-purpose rail tank cars. In contrast, "railbit" is almost straight bitumen and relies on specially heated railcars for flow viscosity. It also requires heated loading and unloading terminals.

Canada has had its own vexations getting crude either to the U.S. or to tidewater. Physically getting crude from Alberta over the Rocky Mountains is nothing compared with the political difficulty of getting through the province of British Columbia and then to the ocean.

"We are not taking Keystone XL [from Canada to the U.S.] or the Trans Mountain expansion [through British Columbia] as done deals," Haas said cautiously. "The deal that is as done as can be is the Line 3 expansion by Enbridge [from Alberta to Superior, Wis., on the Great Lakes]. That is expected to provide about 375 Mbbl/d of capacity in the latter half of 2019. There is another 450 Mbbl/d of systemwide optimization that is possible; with Line 3 that adds up to 825 Mbbl/d by 2020. That is effectively equal to Keystone XL."

Similarly, Mexico's market may be more of a swap than a purchase. The bulk of the country's production is heavy, but its old and inefficient refineries are geared to light crudes. Several sources suggest that Pemex would be wise to invest its limited capital in new production rather than trying to upgrade its refineries. Imports of light crudes from the U.S. would be used to optimize the feedslates for those facilities.

Assessing the need

Commenting on the rush of export terminal plans—there are at least four and as many as seven—Haas said it is similar to the rush to build rail-transfer stations in the early days of the shale bonanza, before pipelines could be built.

"The urgency has taken the industry by storm," he said. "At one point, developers in Canada started more than 800 Mbbl/d of crude-by-rail loading capacity. But actual loadings were 174 Mbbl/d before the 2014 oil price crash and fell afterward to as low as 50 Mbbl/d, and have since recovered to four times that. But I doubt we are ever going to see that 800 Mbbl level."

Stratas calculated that as of June, marine terminal capacity for loading crude along the Gulf Coast totaled 4.5 MMbbl/d. But on that list, only one, the Louisiana Offshore Oil Platform (LOOP) can fully load VLCCs without more costly reverse lightering. In reverse lightering, the big tankers take on a partial load at shoreline docks, allowing them to navigate comparatively shallow channels. Once at sea, other vessels top off their loads before they sail to customers.

By 2020, the U.S. may have as much as 7.5 MMbbl/d of loading capacity if all the terminal projects proceed as expected, Stratas calculates.

Haas recognizes that is a big "if."

"Our forecasts of available crude for export from the U.S. Gulf Coast do not support a need for 7.5 MMbbl/d of export capacity. It's more like half or two-thirds of that at best. That's why this reminds us of the crude-by-rail terminal loading rush earlier in the decade that saw numerous smaller manifest loading terminals replaced by unit-train facilities, neither of which are being fully utilized now," Haas said.

While definite capacities for the proposed VLCC terminals for the Gulf Coast are not yet set, Haas said that at an average of 750 Mbbl/d, there could easily be a need for at least two or three.

"We could easily accommodate four or five large terminals, but those would start to cannibalize the loading volumes from smaller docks," he added.

Apples and oranges

Capacity assessments with regards to marine movements are always a little tricky because they are not ratable the way a pipeline is, noted Hedge at Opportune.

"While one of these facilities can load at 60,000 barrels per hour, that doesn't mean it can export 1.4 MMbbl/d every day. The ships take time to get into position and get connected, then be loaded and disconnected, then maneuver away. All that adds one to three days to the cycle time and takes the actual capacity down to one-third of the actual pump rate," he said.

It is also important to note that tanker operators do not want to pay demurrage costs, so ships are not going to be waiting in line to be loaded. Thus there can be days between vessels.

"From a terminal owner perspective," Hedge said, "they want the U.S. to have just enough export capacity to not induce someone to build another terminal. From a shipper's perspective, they want as much capacity available as there can be. Competition keeps the cost down." Multiple facilities also mean a more reliable supply chain overall, and possibly alternatives for shippers if there are disruptions.

According to Opportune, if U.S. crude production were to increase from 11 MMbbl/d to just 11.5 MMbbl/d—an increase of merely 4.5%—that equates to more than seven additional VLCC cargoes a month.

"In that case," Hedge said, "assuming all additional barrels could flow to the facilities equally without constraint, and that increased production is not offset by a decrease in imports or increase in refining demand, then just one new terminal would suffice. Two would be better. Three would probably be one too many."

How many racehorses?

The one VLCC-capable loading facility, the LOOP off Port Fourchon, La., has 72 MMbbl of storage at Clovelly, La., but only limited pipeline capacity to major Texas and Oklahoma shale plays.

LOOP was originally built as an import terminal but was reconfigured to allow bidirectional flow and load for export.

"While I have not heard of any new pipelines in consideration to Clovelly, it is my understanding that the LOCAP and Capline pipelines are being considered for reversal," Hedge said. "This will be a key step in making the LOOP an essential export player. LOCAP connects Clovelly to the St James [La.] terminal and by extension to crudes coming in from the west and north, while Capline currently moves crude from Clovelly north into the Midwest refining region. A reversal of Capline could bring heavy Canadian and Bakken crudes into Clovelly."

Coleman at WoodMac explained that "the broader theme will be getting VLCC loading access for Texas and Oklahoma producers where there is current pipeline connectivity off the Texas coast. Several offshore and onshore VLCC-capable projects have been put

The Suezmax *Cape Baxley* loads crude oil at SemGroup's Houston Fuel Oil Terminal Co. complex on the Houston Ship Channel. The Marshall Islands-flagged vessel was the first to use the facility's new dock when it opened for business in the third quarter. *Source: SemGroup Corp.*

forward to provide this access. The LOOP export terminal will likely specialize in Gulf of Mexico medium-grade exports, which have been seen in its limited export operation to date."

Looking more closely at some of those proposed loading facilities, Coleman added, "We expect the Tallgrass/Drexel-Hamilton Seahorse Pipeline from Cushing, Okla., to St. James, La., to move forward. A key selling point may be the 'stem-to-stern' service that Tallgrass can offer Rockies producers by transporting crude from the wellhead to export dock on one integrated system."

Similarly, the Trafigura offshore terminal at Corpus Christi "is likely in our view and moving forward through permitting currently. Also, the Enterprise [Products Partners] project is very real. It is likely this project will move forward. Enterprise already has the most extensive crude infrastructure and aggregating capability in the U.S. Gulf Coast market," Coleman said.

Conversely, Coleman reckoned that the Jupiter MLP pipeline from the Permian to Brownsville, Texas, "is unlikely in our opinion given the lack of current infrastructure in Brownsville."

The overarching question in handicapping the various proposals is the total need for number of facilities and cumulative throughput.

Like Haas said, "There is likely overbuild in export capacity looming if all these projects move forward," according to Coleman. "Our current estimate of onshore capacity, should all proposed terminal projects inland move forward is greater than 6 MMbbl/d in capacity. Offshore terminals would be substantially additive to that figure. This compares to our peak U.S. crude export figure of 4.5 MMbbl/d—implying that not all projects on the table today will be necessary, or poor return on investment might be expected for midstream operators if an over-build comes to fruition."

From shale to shore

Any export terminal assumes that there is sufficient pipe to get the oil from wellheads to tanks for loading. That does not seem to be an unrealistic expectation, Coleman said, once the midstream sector gets past the current tightness.

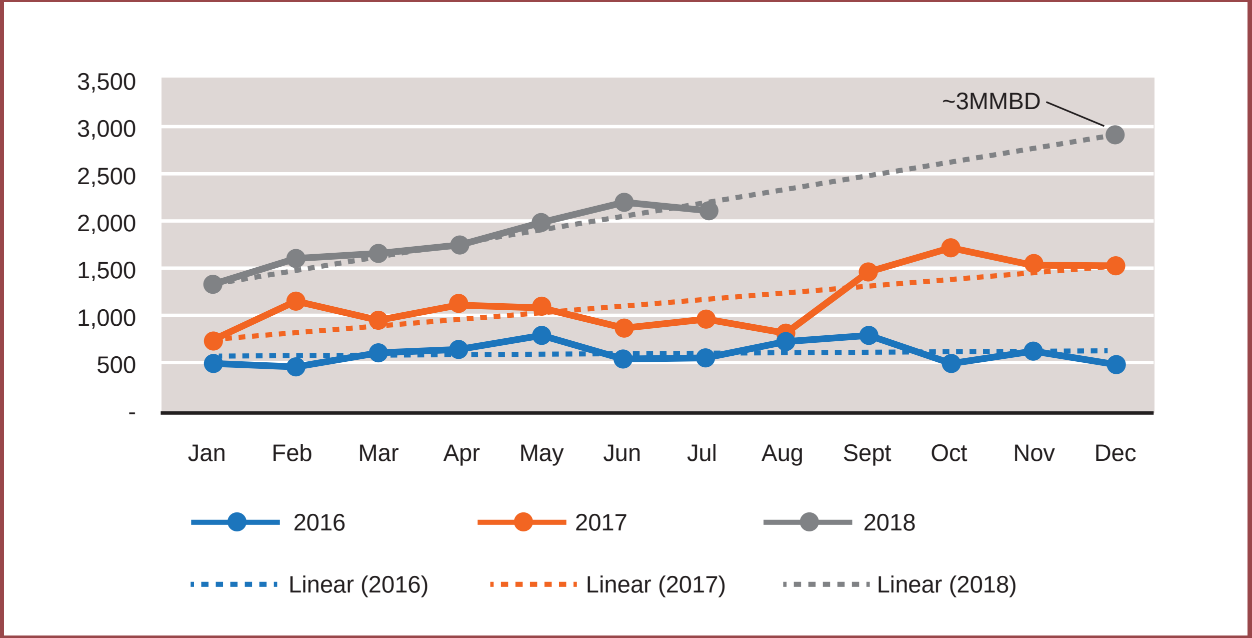
"The most critical avenues for U.S. crude into the future will really begin and end with the Permian Basin," Coleman said. "That region will be the growth engine for the Lower 48 going forward. Having enough pipeline capacity to get that crude production growth into the U.S. Gulf Coast market for export will be critical for the growth to continue. While it is constrained today, huge slugs of capacity are expected online over the next two years to support Permian production well into the future."

All the focus on marine send-out terminals assumes that the midstream sector in the U.S. and Canada will have stepped up and built enough pipe to get from the wellhead to the tanker. Haas said that is a fair expectation.

"With the Capline reversal, the eastern Gulf Coast will be well-served, even including the Diamond line bringing Texas and Midcontinent crude from Cushing to an intertie at Memphis. There are also other important projects flowing to intermediate hubs with existing or pending access to the Louisiana or Texas Gulf Coast, including the Dakota Access Pipeline," he said.

But the Texas markets will be the biggest winners as export volumes burgeon, Haas said. "Corpus Christi

U.S. Refinery/Blender Net Residual Fuel Oil Production



Source: U.S. Energy Information Administration is closest to the Eagle Ford and the Permian," he added. "For crude exports, that makes it a one-drop shop and a one-hop stop. Many Texas barrels can be arranged on one contract with one tariff on the way to the export terminal."

Still, shippers like options, and the global oil market is notoriously volatile. The safest bet is to send crude to an area where there is the alternative of large refining operations if export markets are difficult and differentials tighten to close the export window. That favors the stretch from Houston to Beaumont-Port Arthur, over to Corpus Christi or on to Louisiana. And, Haas added, "There is no refining at all at Cushing." The Midcontinent pipeline hub's last refinery closed in the 1980s.

In handicapping the four proposed export terminals, Lippe is not discounting any of them, but is a bit skeptical about two of them.

"I don't see the advantage of the Tallgrass proposal. Why pump crude from Texas to Louisiana? And why pump more crude to Cushing than already goes there? The oil is coming from South Texas and West Texas and is going out through the Gulf Coast. Why go inland to Oklahoma if you don't have to?" he asked.

That said, Lippe is also less than sanguine about the Trafigura plan for Corpus Christi.

"There is some refining there, but not a great deal, and none of the major oil producers have capacity there. Corpus is just not a primary destination. Houston, Beaumont, and Port Arthur are the largest regional concentrations of refining," he said.

"While one of these facilities can load at 60,000 bbl/hour, that doesn't mean it can export 1.4 MMbbl/d, every day. The ships take time to get into position and get connected, then be loaded and disconnected, then maneuver away."

– **Chris Hedge**, *director, Opportune LLP*

Shippers like options

Lippe said that the most prudent approach is for expanding crude production to be sent where export or processing are equal options. That gives shippers, refiners and traders the widest diversity of choices, especially when dealing with international markets for both crude and refined products.

"The question is not to export one or the other," Lippe stated. "Exports will be anything. Whatever makes the most money, whatever the market wants. The energy companies and traders need to think of new ways to manage their businesses. The approach should not be wide open: Come and get it!"

In some cases, Lippe said, the majors are likely to be exporting to themselves.

"For example, people talk about how much oil Singapore imports. Singapore itself hardly uses anything. It is the refineries around Singapore that import the crude. And who owns those refineries? Some of the same majors that will be exporting from the U.S.," he said.

In effect, what Lippe is suggesting is re-intermediation. After half a century of disintermediation—when the integrated companies sold off their retail and distribution networks, even refineries and tanker fleets—it now may make sense to coordinate those segments to some degree again.

Private equity

The wildcard in plans for new export terminals is private-equity money.

"There is so much of that flowing around looking for projects that all reasonable proposals can be funded. Look at the names that have been circulating: Enterprise, Marathon, Magellan. Those are all reasonable companies. Any terminal plans by names like that have got to be taken seriously," he added.

One way or another, Lippe said, the U.S. has to add about 5 MMbbl/d of export capacity for both crude and refined products in the next seven years, "which is feasible. Saudi Arabia exports 7 MMbbl/d to 8 MMbbl/d from just two ports. China imports about 8 MMbbl/d, so the scale that is needed for the U.S. is not a big deal."

In the meantime, major trunk lines in North America are moving ahead. Lippe expects Keystone XL to be in service in 2019, adding 800 Mbbl/d of transportation capacity to the Gulf Coast. He also expects the lines from Alberta to the coast of British Columbia to go ahead, despite the latter province's resistance.

"Most of the First Nations through whose land the lines will run are behind the projects, and under the Canadian constitution First Nation sovereignty is strong. That has been litigated over and over through the years, and the tribes have 140 wins and no losses. The British Columbia problem will be solved, and Alberta can fulfill its potential," he said.

Flexibility and diversity

It is impossible to gauge which projects will eventually fly, Hedge said.

"It will hinge on the economics and who can hit their subscription marks fastest. However, the Oiltanking/Enbridge/Kinder Morgan terminal provides the most flexibility/diversity of supply. It is reasonably close to shore

Heavy traffic: A tugboat trails the crude carrier *Gold Sun* as it enters the Port of Corpus Christi's channel while the tanker *Minerva Symphony*, right, takes on a load of U.S.-produced oil. *Source: Port of Corpus Christi*

and doesn't require a lot of onshore pipe development," he said.

Jupiter appears to be all but a done deal, Hedge added, "but is a significant development. And while Trafigura has good access to well-positioned assets, it is facing opposition from the Port of Corpus Christi. Tallgrass will have to compete with LOOP. At this point, my money is on Oiltanking/Enbridge/KM and Jupiter, Tallgrass and Trafigura are less likely, and with Enterprise potentially coming in from behind."

The plan by Oiltanking, Enbridge, and Kinder Morgan is to build a new 10 MMbbl crude storage terminal in Freeport, Texas, connecting to a new offshore loading facility by 2022. The loading terminal would be about 30 miles offshore. The terminal would be connected with the Gray Oak Pipeline from the Permian to Corpus Christi. That is a 700 Mbbl/d line planned by Phillips 66 Partners and Andeavor, which recently combined with Marathon Petroleum. Kinder Morgan has an existing crude pipeline from the Eagle Ford to Sweeny, Texas, near Freeport and potentially to the Seaway system from Cushing in which Enbridge holds a 50% interest.

The Jupiter Offshore Loading Terminal (Jolt) is an add-on to a greenfield project to build out a crude/condensate upgrading facility, fuel blending facility, and an import/export marine terminal for crude and refined products. It will be supplied from a proposed 670-mile, dedicated high-gravity crude pipeline that originates in Orla, Texas, with additional injection and offtake points at Pecos and Three Rivers, Texas.

"If you assume that the pipeline and onshore terminal is a done deal," Hedge said, "then adding about a five-mile pipe to deepwater and the loading platform is a minor addition. The advantage to being in Brownsville is that deepwater is only 5 miles offshore, as opposed to the Oiltanking/Enbridge/KM proposal which is about 30 miles offshore or Tallgrass which is more like 80 miles offshore. At about $10 million per mile to develop, the cost savings is significant."

The Tallgrass/Drexel-Hamilton proposal "is much more than a pipeline," Hedge added. "It includes plans for a new onshore terminal called the Plaquemines Liquids Terminal (PLT). The Seahorse Pipeline will have the capacity to transport 800 Mbbl/d. The PLT will load post-Panamax vessels (up to 1 MMbbl) and be operational by the second quarter of 2020. It will also incorporate a separate offshore pipeline extension that would give PLT the added capability of loading VLCCs by third-quarter 2021."

Farther in the distance

Trafigura's Texas Gulf offshore crude export terminal would be about 15 miles off the coast of Corpus Christi and includes an onshore storage terminal connected to an offshore loading terminal by two parallel, 30-inch-diameter pipelines. It would have capacity of 500 Mbbl/d to load VLCCs. The terminal will be linked to Plains All American's planned Cactus II crude pipeline. Plains subscribed to about 300 Mbbl/d. Plains holds 150 Mbbl/d on the existing Cactus line.

"This project is facing opposition from the Port of Corpus Christi," Hedge noted. "The port is looking into dredging and widening its ship channel to accommodate VLCCs in the Harbor Island area."

Enterprise is "aggressive at expanding their footprint are doing their FEED work," Hedge said. "They have not announced a location although speculation and their existing footprint would suggest Houston. If they go to an open season, then it will become much more realistic."

Magellan is focused on expanding pipeline capacity, he noted. "They are, through their Seabrook Logistics venture with LBC Tank Terminals, expanding their crude/condensate storage capacity and adding a Suezmax dock to the Seabrook terminal. It would be logical for them to be considering it, but I haven't heard that they are seriously looking into it."

In a final note, Hedge advised to "follow the money. If there is a need for capacity then capacity will generally be built, so I don't believe that any corridors are being neglected from a takeaway capacity standpoint. I think it is important to keep an eye on the natural gas and NGL processing and takeaway capacity—because lack of that can curtail crude production."

What jumps to his mind are EPIC Midstream's planned 590 Mbbl/d crude line from the Permian to Corpus Christi; and Energy Transfer Partners' 600 Mbbl/d crude line from Midland to Nederland, Texas. There are also additions planned to several expansions to existing systems. ■

***Gregory DL Morris** is a freelance writer based in Chapel Hill, N.C., specializing in energy and petrochemical topics.*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In a scene common in thousands of Third World cities, an LP gas vendor in Bangkok relies on basic transportation to get his product to customers. *Source: Shutterstock/FH 16*

Products' Potential

Petroleum product exports were a big business before the crude export ban went away and trends indicate sales abroad will continue to grow.

By Paul Hart

Rancagua, Chile, lies well off South America's well-trod tourist path, some 75 miles south of Chile's bustling and very chic capital, Santiago. You can get there from here but it takes some doing.

It's a blue-collar town. Copper mining in the nearby Andean foothills, which rise from the city's eastern suburbs, and thousands of acres of surrounding vineyards that produce Cabernet, Merlot and Carmenère grapes, which become top-quality wines, support the local economy. Homes are modest, the natives friendly. No Joe Sixpack here: Visitors can expect a bottle or two of very good, locally produced vintages to appear even for a modest lunch, dinner or the "once," Chileans' traditional, late-night snack.

Part of Rancagua locals' daily routine in every neighborhood is the passing of a flatbed truck or pickup loaded with LP gas tanks, which look similar to that thing under your patio grill. The vendors ring a bell as they drive along—think ice cream truck—to alert everyone in advance of their arrival so residents can haul out an empty tank and swap it for a full one.

Such neighborhood LPG sales are hardly unique to this place. Thousands of villages, towns and major cities across the globe that lack natural gas service rely on LPG.

And increasingly, the liquefied propane/butane mix in those tanks worldwide is coming from U.S. wells.

Good to great

There never was a ban on U.S. petroleum product exports. Foreign markets for LPG—as well as gasoline, diesel, jet fuel and marine bunkers—have gone from good to great as the domestic industry strives to find new markets for rising crude oil and natural gas production. The U.S. passed Russia and

Saudi Arabia during the third quarter to become the world's largest crude producer, with more than 11 million barrels per day (MMbbl/d) in September, and has been the world's largest gas producer for some time.

More recently, the downstream end of the U.S. energy chain added ethane and LNG to that a la carte product menu.

Consider: The U.S. Energy Information Administration (EIA) said in its *Petroleum Supply Monthly* report issued at the end of September that finished motor gasoline exports were up 17% in July, year-over-year (yoy). They rose a substantial 20.3% from the prior month. Numbers like that are understandably "positive," Credit Suisse said in an investment analysis, in contrast to domestic gasoline demand that was flat in first-half 2018 compared with the prior-year period.

"Recall that Gulf Coast refiners moving product to Latin American markets prevents gasoline gluts and supports higher PADD I to III margins," Credit Suisse noted.

Over and under

Credit Suisse had more information to report. For another major petroleum product, it said, "We have seen a clear trend by which weekly data is overestimating domestic demand and underestimating jet fuel export demand."

"A combination of low oil prices, a rapidly expanding middle class in Asia and booming freight markets driven by expanding world trade and e-commerce are fueling increased demand for jet fuel worldwide," IHS Markit said in a fourth-quarter research report. "However, that growth does have potential risks that could hamper demand, namely a greater penetration of sustainable aviation fuels and efficiency gains..."

The report estimated worldwide jet fuel demand will rise from around 8% of total refined product demand in 2017 to more than 10% by 2040. The global market will reach more than 9.5 MMbbl/d by 2040, compared with demand of nearly 7.45 MMbbl/d this year.

"Thanks largely to low oil prices and strong growth in air travel, particularly in Asia, jet fuel is a fast-growing product, with global jet fuel demand growth comfortably exceeding 4% in the last two years," said Louise Vertz, director, refining and marketing research at IHS Markit, and lead author of the IHS Markit analysis. "In a refined-fuel market that has had sluggish annual growth of just shy of 1.5% overall, that is a bright spot for refiners and is one of the few refined products we expect to see gain consistent demand growth through 2040. However, there are some potential challenges that could inhibit that demand growth, particularly increased market penetration of sustainable aviation fuels and increased fleet efficiency."

Developed-nation, OECD markets currently claim 58% of the jet fuel market. That share will decline to about 48% as non-OECD market growth continues, driven by Asian growth, according to IHS.

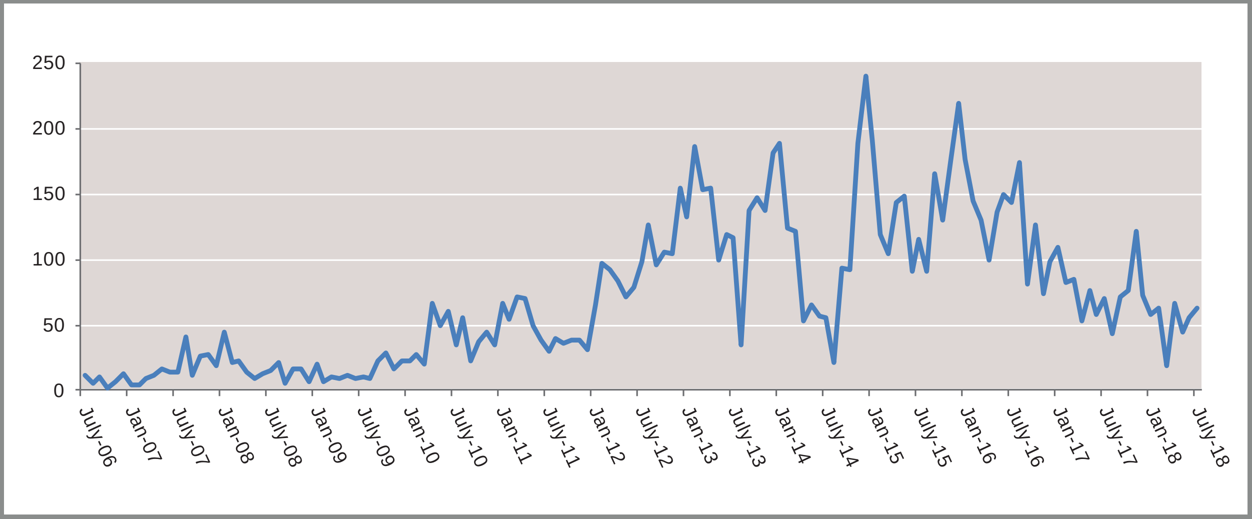
The advantages

The U.S. has two things working in its favor as it strives to cut a bigger and bigger slice of the worldwide product sales pie:

- Its swelling production from the shale plays; and
- The world's largest and most sophisticated refining industry, coupled with rapidly growing gas liquefaction infrastructure.

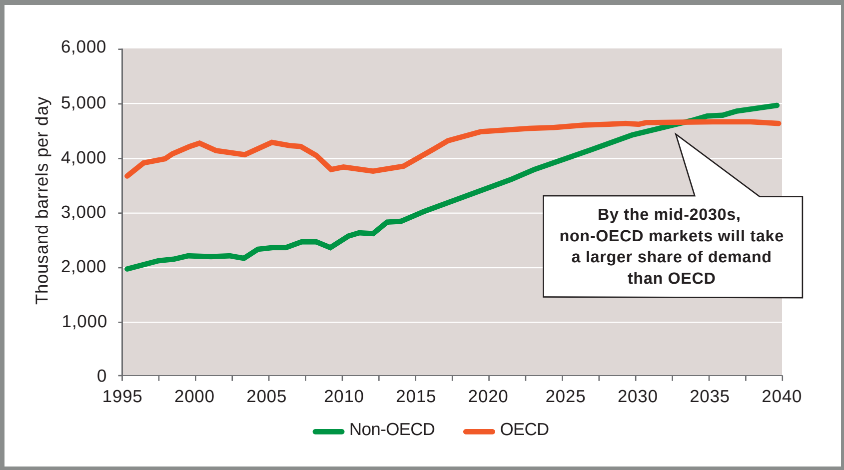
The nation's energy industry can produce crude, refine it and ship it around the world at a lower cost than potential competitors can. On the gas side, the first liquefaction operations were low-cost, bolt-on projects that

U.S. Gasoline Exports (thousand barrels per day)



Source: U.S. Energy Information Administration

Jet Fuel Demand Outlook



Source: IHS Markit

made use of existing docks and tankage originally intended for gas import operations built before the shale gale hit. Even greenfield LNG operations coming online next year and in 2020 have access to the nation's well-developed gas pipeline grid and utility services not found abroad.

Overall, U.S. midstream infrastructure beats anything the rest of the world has and gets a lot of the credit for creating that cost advantage.

The challenges

The nation also faces two challenges to product exports, Bob Broxson, managing director in BDO USA's energy disputes practice, told *Midstream Business.*

"One of the barriers the U.S. has is getting sufficient infrastructure in place to get all the products that we have to the right locations," Broxson said. "We have a significant amount of crude oil production growth in the U.S. but we don't have the infrastructure to move all of that crude oil to refineries.

Pipes and terminals are in place—but not always the right place.

"The other is competition. We don't know exactly what OPEC will do from an output standpoint. We know that our production continues to grow and we see some shortfall in what OPEC is doing. But we don't know if that is due to a lack of cooperation or a production issue, or what that could be," he added.

The growing export trade creates opportunities, and that brings predictable growth in M&A activity and capex budgets. For example at the end of the third quarter, Marathon Petroleum Corp.'s MPLX LP midstream subsidiary purchased what it will call its Mt. Airy Terminal on the Mississippi River from Pin Oak Holdings LLC for $450 million in cash and debt. It's near Marathon's big Garyville, La., refinery.

MPLX ranks No. 8 on the *Midstream Business* Midstream 50 list of the sector's largest publicly held firms.

"This acquisition provides an excellent platform for MPLX, as production growth and refining output increase the requirement for additional export capacity," MPLX President Michael J. Hennigan said in the firm's purchase announcement. "With a prime location on the Mississippi River and proximity to over 2 MMbbl/d of refining capacity [nearby], this terminal will serve as a platform to meet growing export needs, expand our third-party business, and give MPLX tremendous flexibility to help its customers meet upcoming International Maritime Organization (IMO) fuel standards."

Mt Airy has 4 MMbbl of third-party leased storage capacity and a 120,000-barrels-per-day (Mbbl/d) capacity loading dock. MPLX noted the terminal could expand storage to 10 MMbbl/d and add a second dock of equal capacity.

Meanwhile another big player, the Midstream 50's No. 5-ranked Enterprise Products Partners LP (EPD), announced the addition of a new NGL fractionator and expansion of its Enterprise Hydrocarbons Terminal (EHT) on the Houston Ship Channel. The fractionator will have a capacity of 150 Mbbl/d, increasing EPD's total Mont Belvieu fractionation capacity to 905 Mbbl/d. The export dock will add 175 Mbbl/d of loading capacity, enabling it to load a very large gas carrier in roughly three days.

And, early in the fourth quarter, supermajor Chevron Corp. told *Reuters* it's seriously considering building a refinery on the Houston Ship Channel, or buying an existing plant for expansion and modification. The plant would be tuned to process light sweet shale crudes—unusual since much of the Gulf Coast's existing refining capacity needs heavy sour feedstocks.

Distillate downturn

Distillate leads U.S. petroleum product exports. "Unlike motor gasoline, which is used almost exclusively for transportation, distillate fuel has a variety of uses, including as a heating fuel in homes and businesses, as a fuel for certain industrial processes, and as a transportation fuel for both light- and heavy-duty vehicles," the EIA noted in a recent report. Some 27% of the nation's distillate production went abroad in 2017, although distillate exports fell slightly in the first half of 2018 from 2017 levels.

"Distillate exports were a disappointment" in the first half, according to a Tudor, Pickering, Holt & Co. (TPH) report, which pointed out "the culprit here is Europe," where tightening environmental laws restrict the use of diesel engines in cars and trucks. Some of that loss was made up through Latin American and Mexican purchases.

"Distillate exports had a big year last year (+17%) so the comp is tough, but this is certainly an area to monitor going forward," TPH noted.

Latin America is a good market to be in, according to a recent review of that region's product demand trends by Hart Energy's Stratas Advisors.

"Latin American petroleum product consumption is projected to grow at an annual average rate of 1.7% CAGR [compound annual growth rate] through 2025, to a total of 10.72 MMbbl/d. [Overall] demand for light transportation fuels—gasoline, middle distillate and jet fuel—will grow nearly 1.8% CAGR from 2016 to 2025," it noted.

However, watch for a significant uptick in distillate sales in future years, according to EIA and industry analysts, thanks to a new marine fuel mandate (see story below).

Gasoline's spark

In contrast, gasoline exports have enjoyed "solid growth," TPH said, elaborating on the trends noted above. "The star of the show [in May numbers] was once again Mexico, which accounted for 58% of U.S. gasoline exports in the month and 68% of the yoy growth. Planned and unplanned refinery outages in Mexico were up approximately +75% yoy in the first half of the year, stimulating demand for U.S. barrels."

BDO's Broxson added that "close to 60% of all gasoline exported from the U.S. goes to Mexico with the remainder essentially going to South and Central America."

Indeed, Mexico is not alone in its refining challenges, and a recent Credit Suisse report to investors revealed more information.

"Given South American refining systems continue to struggle, we expect product exports to remain elevated," Credit Suisse advised investors in that report.

Credit Suisse was not the only firm examining the problem.

Contributing to technological and volumetric handicaps, South American product markets have been hit very hard by the "meltdown" in Venezuela's refining sector, as an RBN Energy study put it.

"Venezuela's national oil company PDVSA—previously a dominant player in the region—has left refineries and storage terminals underutilized and starved of investment. U.S. Gulf Coast refineries have partially filled the gap by increasing product exports to the region, but an opportunity now exists

The Sulfur Switch

A pending change in marine fuel standards promises to have a big, but temporary, impact on worldwide crude oil supplies and petroleum product demand. As demand for one product goes away, demand for another will jump substantially.

In 2016 the UN's International Maritime Organization (IMO) set a new, 0.5% sulfur content cap on marine fuels, effective Jan. 1, 2020. Ship bunkers have been one of the last widely traded petroleum products—essentially refiners' leftovers—that still allow substantial sulfur as air-quality concerns squeezed the element out of other products. IMO currently allows use of high-sulfur fuel oil (HSFO) with as much as 3.5% sulfur.

The industry will adapt, analysts say, but it will take a while. The switch is the biggest fuel swap the marine business has tackled since a move to petroleum bunkers from coal 100 years ago.

The choices

The change has shipping firms scrambling, according to OPEC's recent "World Oil Outlook." OPEC projected some 1,500 vessels will have scrubbers installed between now and the deadline. At present, about 500 vessels are so equipped, it noted.

The alternatives for ship owners are to switch to low-sulfur distillate, or install expensive stack scrubbers. Both options will incur costs for either new dockside piping and tankage or vessel retrofits costing $2 million to $3 million per ship.

In mid-October, Sweden's Stena Bulk, a major crude oil and petroleum product tanker operator, announced a deal for scrubbers that meet Lloyd's of London exhaust gas-cleaning standards.

Industry analysts place worldwide demand for HSFO at a substantial 3.3 million barrels per day.

"In order to produce sufficient volumes of middle distillates, the global refining system is expected to increase runs by around 400,000 [barrels per day] in 2020 (additional to the case if no IMO regulations were adopted)," OPEC said.

For crude producers, the change will mean heavy sour crude prices will weaken further, "potentially severely" from 2020 onward, while light sweets will command a greater premium, the report added. Morgan Stanley recently noted simple refineries will take the hardest hit while complex refineries will be able to increase their share of the product market due to their ability to use lower-cost, high-sulfur feedstocks to produce low-sulfur products.

"We think improved distillate, gasoline, and coker economics tied to [the] IMO 2020 theme will drive cash levels to about 25% of today's market cap by 2021," U.S. Capital Advisors said in a research report.

Reuters recently published the results of a refinery survey that found HSFO production and demand will continue to be sizeable after 2020. The vessels that gain stack scrubbers will provide some demand, along with use of "the leftovers of an oil refiner's output," as the report put it, for power generation in some Third World countries with lax air emissions laws.

—Paul Hart

for private investment to fill the refining and storage void left by PDVSA, and also to meet new demand for low-sulfur bunker fuel arising from stricter [IMO] shipping regulations, which will come into effect in January 2020," RBN said.

Venezuela is not alone in its struggles to maintain refining capacity, although its problems may be the greatest. The problem is not confined to that part of the world. For example, Oilprice.com recently offered a grim look at Ukraine's refineries.

"Ukraine's oil sector has remained in tantalizing agony, as only one out of the country's six refineries is currently functioning (at a 10% utilization rate) and most of the products supply [has been] taken over by neighboring countries. All this with no end in sight. Almost every refinery was built with some sort of Russian involvement—as an owner, co-investor or crude supplier—yet after 2014, against the background of unprecedented antagonism between Ukraine and Russia, Russian companies have left the country for good. Now the question is: Who will step into the vacant spot? So far, it seems that no one is willing to," Oilprice said.

So with many other out-of-date and poorly maintained refineries limping along around the world, the top-flight U.S. Gulf Coast refineries are likely to take ever-larger chunks of the world's petroleum product market, according to industry observers.

Tipsy gas sales

The domestic debate over the ethanol content of U.S. retail gasoline could impact motor fuel sales abroad, Turner, Mason & Co. noted in a third-quarter report. A plan to permit domestic motor fuel sales at the pump with 15% alcohol content year-round, approved by President Trump in October, is expected to further slow any increase in U.S. reformulated blendstock for oxygenate blending (RBOB) demand. And refiners will be looking for new markets abroad.

"An argument against the waiver by refiners is that the higher the ethanol content, the less fuel the refiners will produce through their refinery. This is a real argument, and volumes might seem small until you consider the amount of gasoline consumed in the U.S. Gasoline consumption in the U.S. is on the order of 9 MMbbl/d to 9.5 MMbbl/d. And 5% of that is over 450 Mbbl/d," Turner Mason said of RBOB demand.

China's market

China offers an important and growing fuels market, according to TPH.

"Data from China Customs showed crude imports of 8.5 MMbbl/d in July 2018, a +1% increase month-over-month and a +5% increase yoy," it said. In addition to China's economic growth, new tax laws have cut the already weak economics for dozens of simple "teapot" refineries that lack reforming or catalytic cracking capacity.

"Estimated teapot utilization dropped considerably to 58% from 63% as refiners have dialed back due to recent tax changes negatively impacting economics," the report added.

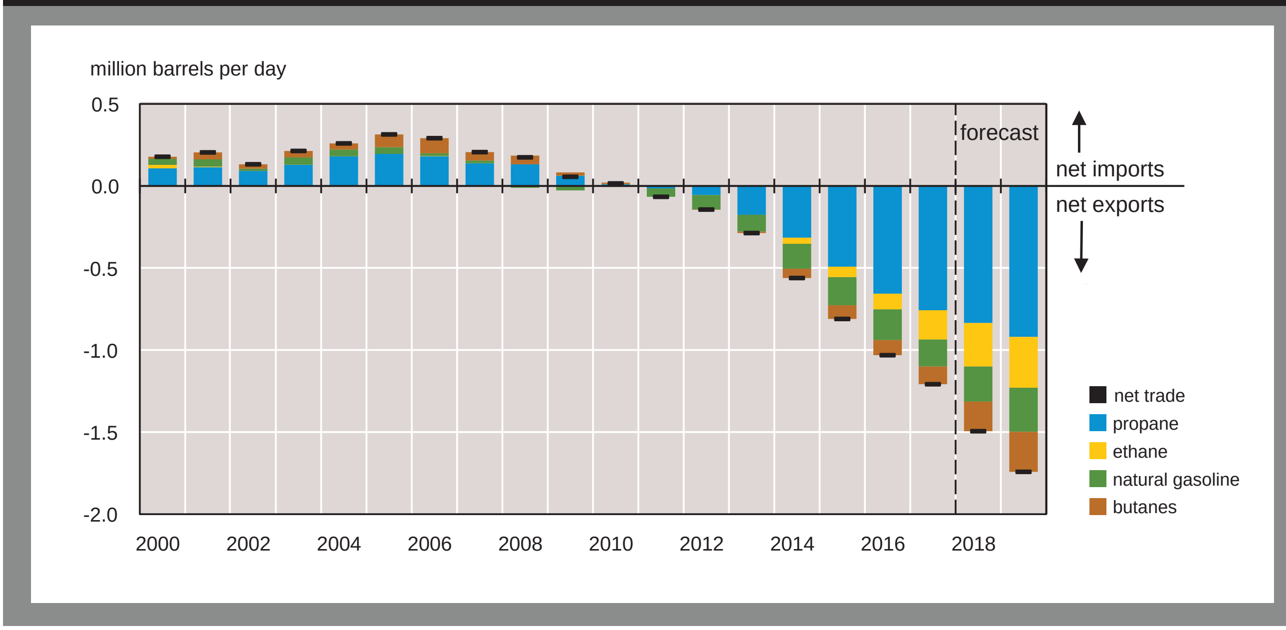
China will add 900 Mbbl/d of crude distillation capacity late this year and in early 2019, but the Asian powerhouse will see transport fuel productions grow less than many expect, according to ESAI Energy's *China Watch,* published early in the fourth quarter. "Most notably, ESAI Energy projects China's overall diesel production could grow by 50 Mbbl/d or less in 2019. The growth of China's supply of middle distillate and overall transport fuel output has implications for Asian product markets and China's least sophisticated independent refineries struggling to remain viable in the domestic market."

The publication added that two new refineries will focus on petrochemicals rather than fuels. Hengli Petrochemical and Zhejiang Petrochemical, each with 400 Mbbl/d of distillation capacity, are configured to produce a total volume of 8.5 million tons of paraxylene with transport fuels produced only as byproducts.

"The transport fuel component will be more heavily weighted toward gasoline and jet fuel, yet the new refineries will produce only about half the diesel that a typical refinery of the same size would produce. Moreover, ESAI Energy expects supply

A product tanker loads at a Corpus Christi, Texas, dock before it weighs anchor for a foreign port. The South Texas city's multiple refineries, seen in the background, enjoy close access to Eagle Ford crude oil and close proximity to key Latin American markets. *Source: Port of Corpus Christi*

Net U.S. Trade in NGL



Source: U.S. Energy Information Administration

from the new projects to displace some production of other domestic refineries.

"Competition from the new projects could be the last straw for some independent refiners that are already hit by shrinking demand, rising crude prices, new tax rules, and increasingly stringent environmental measures," said Yao Wu, ESAI China analyst of the teapots. "Added supply from sophisticated new players will add to the economic pressure on the vulnerable refiners, forcing some to curb production of diesel and other products."

Ethane and more

The NGL market for ethane, propane, butane and natural gasoline is strong and getting stronger, according to many observers.

"As compared with gasoline and refined products, most of the LPG that is exported from the U.S. goes to Asian markets including Japan, China, South Korea and Singapore," Broxson added. "Mexico is a large importer of LPG, as well. U.S. exports of LPG basically doubled between 2015 and 2017. According to the EIA, 90% of these exports are from Gulf Coast ports."

In addition to the well-established export markets for propane and butane, the U.S. has a growing business in shipping its abundant ethane production abroad, backing out naphtha and other petrochemical feedstocks. East Daley took a long look at ethane exports in a September research report after a lengthy discussion of surging domestic demand for ethane to support new domestic petrochemical capacity, primarily around the Gulf Coast.

"In addition to increased domestic cracker demand, Gulf Coast ethane exports have reached new highs this year … New domestic demand and growing exports have drawn significantly on Gulf Coast ethane stocks, which are down 10 MMbbl, or 20%, from the start of 2018 through June," the report said.

"Higher ethane prices likely provide upside to midstream companies, like Targa Resources, DCP Midstream, Williams and Enterprise Products Partners … Companies with NGL pipelines to Mont Belvieu [Texas NGL hub], such as ONEOK, Enterprise Products and Energy Transfer Partners, may also benefit as higher ethane prices result in more ethane recovery and therefore more NGL volumes on the pipelines."

"U.S. demand growth has slowed below the rate of production growth, forcing all incremental volume to be exported," East Daley said in another report. "This trend can be seen … as Houston, the primary export port due to its proximity to Mont Belvieu, has increased export volumes to historic highs reaching 900 Mbbl/d in July."

In the middle

As the world's demand for hydrocarbon fuels and feedstocks grows, the U.S. midstream—from Permian or Bakken wellheads to those retail LPG salespeople ringing their bells as they creep through Rancagua's streets—will play a crucial role in 2019 and beyond.

Broxson emphasized midstream infrastructure is key to meeting the world's demand for more refined products. But "midstream infrastructure" means more than gas plants and pipes.

"We have to think docks and terminals," he said. "I would consider that a part of the midstream, you have to have the terminals to go along with pipeline expansion, etc.," to get product to customers. "It comes down to access at the port." ■

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On a clear day you can see Mount Fuji: The summit of the famous volcano looms in the distance just above the Tokyo skyline and the city's busy port. Japan is a major customer for U.S. energy exports. *Source: Shutterstock/BNK Maritime*

Tops In Exports

Several companies in the sector play crucial roles as the midstream grows to handle greater sales abroad.

By Erin Pedigo

As 2018 draws to a close, the U.S. is exporting an ever-larger percentage of its crude oil, natural gas and petroleum product output. More infrastructure—docks, terminals, liquefaction plants, gas storage, rail sidings, etc.—is needed to handle the tankers and pipelines used to transport these swelling volumes.

Midstream Business profiles here some of the key exporter players, five traders and five operators, whose business spans the globe. International trade takes a large chunk of their market.

According to data from the website *Trading Economics*, in 2017, the value of exported mineral fuels, oils and distillation products topped $200 billion—$201.65 billion, to be exact.

Likewise, data from the U.S. Census Bureau for January-September 2018 placed the nation's total exports at a nominal $1.2 trillion. That's still lower than total imports but still impressive.

Europe seeks LNG, as Iran produces less oil and also exports less, and "the changing U.S. energy trade balance is still dominated by crude oil imports," according to the U.S. Energy Information Administration.

The American Geosciences Institute reported that in second-half 2018, the U.S. exported roughly 7.6 million barrels of petroleum per day (MMbbl/d), alone, with the largest markets in Mexico and Canada and to 180 countries in all.

The fall of imports

"The recent increase in domestic oil production, especially since 2010, has had a significant impact on U.S. petroleum imports and exports. From 2005 to 2015, the U.S.' reliance on petroleum imports fell from 60% to 25% of total consumption, while exports increased by more than 300%. Since 2015, imports have remained fairly steady at about 10 MMbbl/d, but exports have continued to increase, from 4.7 MMbbl/d in 2015 to 7.6 MMbbl/d in early-mid-2018," the institute said.

It's no surprise that established foreign commodity traders play key roles in the U.S. export surge, thanks to their established contacts and infrastructure. The companies profiled here are all making strides in the export game. Some are busy on joint ventures (JV) constructing pipelines, others have bankrolled large export deals, and others have signed purchase and sale agreements for products.

TRADERS

Trafigura

- Geneva, Switzerland

The commodity trader, which trades petroleum products, metals and minerals, had $86.9 billion in group revenue, $52.8 billion in total assets, $657.9 million in EBITDA and $979 million in gross profit according to its mid-2018 interim financial and business highlights.

According to that report, "total volumes traded in oil and petroleum products grew by 16% from the same period a year ago to an average 5.8 MMbbl/d, while metals and minerals total volumes increased by 48%."

CFO Christophe Salmon said, "the fall in [oil sector's] profitability was the result of a major shift in the oil market during the period from a contango structure, where forward prices are higher than spot prices and act as an incentive to hold inventories, to the opposite condition of backwardation, where holding stocks is costly. The oil market became backwardated in October 2017 as a consequence of rising spot prices in response to production curbs by OPEC."

According to its website, Trafigura sources its oil from public E&Ps, supermajors and national oil companies; it has a blending hub in Louisiana and has continually expanding domestic lease activity in the Eagle Ford Shale.

Trafigura is "growing business" in major importer China, but specific to LNG, is focusing on expanding its European natural gas business to cover the market there, according to the website.

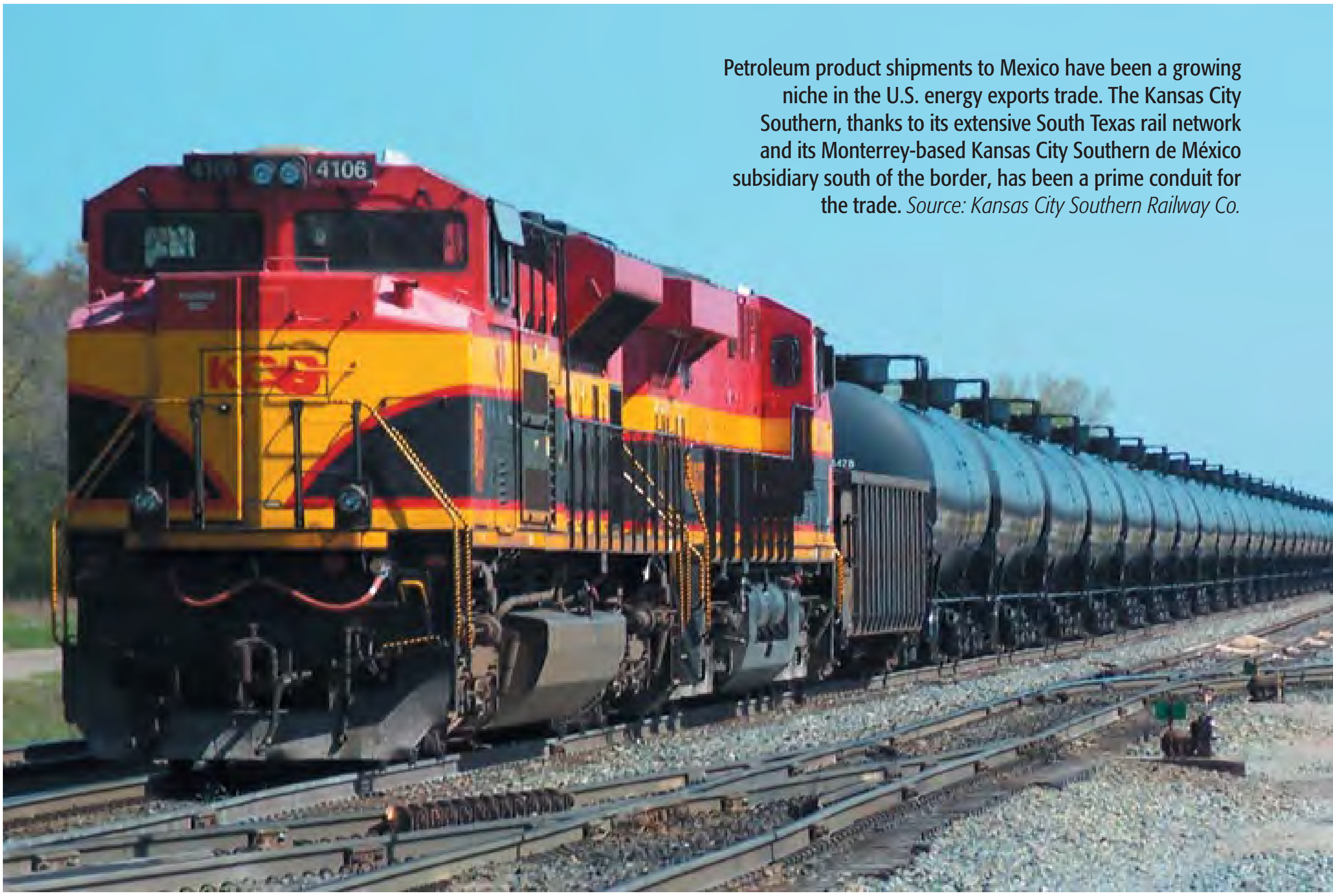
Glencore Plc

- LSE: GLEN
- Baar, Switzerland

Glencore, a global commodities marketer and producer, had $14.8 billion in adjusted EBITDA for 2017, more than 150 assets across more than 50 countries, according to its website. Glencore moves 6 MMbbl/d to customers, and markets gas in Europe.

As of its report at the six-month mark of 2018, Glencore had increased adjusted EBITDA by 23% to $8.3 billion, and its overall net income increased by 13%. The report notes that the company acquired "a 78% stake in ALE, Brazil's fourth-largest fuel distributor," in an effort mainly targeting downstream.

The Netherlands' port of Rotterdam is a major crude oil and petroleum products hub for Europe and the world. *Source: Shutterstock/VanderWolf Images*



Petroleum product shipments to Mexico have been a growing niche in the U.S. energy exports trade. The Kansas City Southern, thanks to its extensive South Texas rail network and its Monterrey-based Kansas City Southern de México subsidiary south of the border, has been a prime conduit for the trade. *Source: Kansas City Southern Railway Co.*

Vitol

■ **Geneva, Switzerland**

Geneva-based Vitol has refining, terminaling and storage and, according to its website, ships 349 million tonnes of crude oil and products annually, trades more than 7 MMbbl/d of crude and petroleum products daily, and has 250 ships transporting its cargoes, which include bitumen, naphtha, natural gas and oil, at any one time.

As of September, Vitol and Cheniere Energy Inc. signed a 15-year LNG purchase and sale agreement, under which Vitol would purchase 0.7 million tonnes per year from Cheniere Marketing on a free on board (FOB) basis, according to a press release.

According to an announcement, Russell Hardy, Group CEO at Vitol, said, "We are delighted to be working with Cheniere, a pioneer in U.S. liquefaction. Vitol is committed to the long-term development of the LNG market. We believe that LNG has an important role to play in the future energy mix and that its evolution will require a more flexible and tradeable LNG market."

Noble Group Ltd.

■ **SGX: CGP**
■ **Hong Kong**

Noble Group markets, processes, financially backs and transports energy assets and other commodities. Its energy assets include oil liquids, coal and LNG.

"Noble is a major participant in the global physical oil market, trading large physical volumes including crude and refined products via ship, barge, pipeline, truck and rail. Noble has blending and wholesale capabilities in North America and the Caribbean, with long-term leases on liquid storage capacity across the globe. Working with producers, consumers and refiners to manage exposures along the supply chain, we offer customers a variety of services that go beyond the traditional commodity price hedging solutions, such as structured finance solutions," its website says.

The company says of its LNG franchise that it is built on the company's existing relationships with Asian energy customers. Late last year, according to *Reuters*, the company hunted for a buyer for its LNG units "to cover debts and reduce credit exposure after a first-half loss of $1.9 billion, [according to sources.]."

The *Reuters* report also said that Noble, in a measure to only focus on its "core Asian coal business after a crisis-wracked two years," [was] selling its North American gas and power business to Mercuria and also said it would sell its capital-intensive oil liquids business, leaving it focused on hard commodities."

Gunvor Group

- Geneva, Switzerland

The Swiss-based global commodity trading house, which also has a major office in Nicosia, Cyprus, sources crude and refined products from more than 100 countries. It reported that in 2017, total trading volumes increased to 184 million tonnes from 153 million in 2016—the company noted that the calculation removes emissions, "which can cause significant swings in results."

Revenue for 2017 was US$63 billion, up from US$47 billion in 2016, the website reported.

Gunvor opened a Houston trading office in 2017. The company's terminals and refineries serve Europe, and its pipelines and storage mix is split between Germany (Transalpine Pipeline) and Panama. Gunvor has a minority stake in Petroterminal de Panama, with a primary asset of a pipeline with 600 Mbbl/d throughput capacity linking the Atlantic and Pacific.

"There are also storage locations at both ends of the pipeline with a total of around 9 MMbbl split approximately equally between the two coasts. The pipeline offers a shortcut for crude cargoes around Latin America and an alternative to the Panama Canal. It gives us increased sourcing opportunities, a market presence in the Americas and access to additional storage capacity," a company profile said.

OPERATORS

Buckeye Partners LP

- NYSE: BPL
- Houston
- No. 13 on the Midstream 50

The publicly traded MLP owns and operates global assets for the transportation, storage, processing and marketing of liquid petroleum products. According to its company profile, it has more than 135 liquid petroleum products terminals with aggregate tank capacity of more than 176 MMbbl.

In August, the company released second-quarter financial results. It had an adjusted EBITDA that was lower, at $254.9 million, than second-quarter 2017's $269.2 million, and also a lower net income attributable to unitholders, at $91.9 million, compared with second-quarter 2017's $112.7 million.

In late April, the company announced the formation of a JV with Phillips 66 Partners LP and Andeavor, now a part of Marathon Petroleum's MLPX LP, "to develop a new deepwater open-access marine terminal in Ingleside, Texas. The South Texas Gateway Terminal will be constructed on a 212-acre waterfront parcel at the mouth of Corpus Christi Bay … to serve as the primary outlet for crude oil and condensate volumes delivered off of the planned Gray Oak Pipeline from the Permian Basin. The terminal … will offer 3.4 MMbbl of crude oil storage capacity, connectivity to the Gray Oak Pipeline and two deepwater vessel docks capable of berthing very large crude carrier petroleum tankers," a press release said.

"This project expands our presence in the important Corpus Christi market, which we believe offers strong competitive advantages for waterborne shipments of crude oil and other petroleum products from the fast-growing Permian and Eagle Ford shale plays," said Khalid Muslih, executive vice president of Buckeye and the president of its global marine terminals business unit.

Cheniere Energy Inc.

- NYSE: LNG
- Houston
- No. 10 on the Midstream 50

Cheniere operates the first large-scale U.S. LNG liquefaction project, Sabine Pass, in Cameron Parish, La., which loaded the first large-scale LNG shipment from the Lower 48 states in February 2016. Work continues on the plant, which eventually will have six liquefaction trains.

It also is moving forward on its Corpus Christi Liquefaction project on Texas' Corpus Christi Bay, which is nearing completion and is expected to go onstream in 2019. In September, Cheniere Energy completed a corporate roll-up with its Cheniere Energy Partners MLP unit.

It is noteworthy that in 2017, its EBITDA jumped 1077% and Cheniere zoomed from No. 40 in 2017 to No. 10 this year in the *Midstream Business* Midstream 50 rankings—the biggest one-year climb ever by a firm.

As aforementioned, Vitol and Cheniere recently signed a 15-year LNG purchase and sale agreement, under which Vitol would purchase 0.7 million tonnes per year from the Cheniere Marketing unit on an FOB board basis. The liquefaction project is being designed for five trains with expected aggregate nominal production capacity of up to 22.5 million tonnes per annum (mtpa) of LNG.

Enterprise Products Partners LP

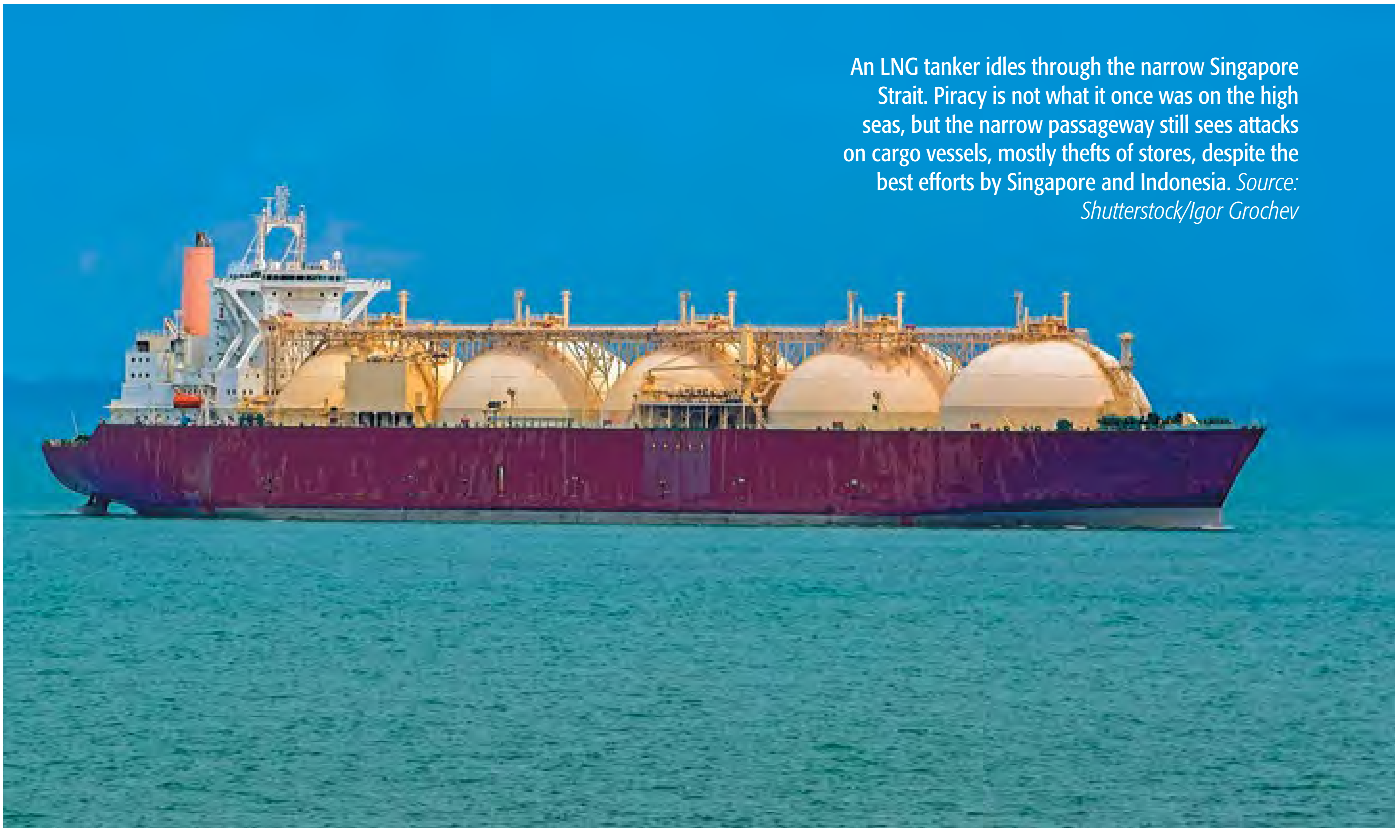
- NYSE: EPD
- Houston
- No. 5 on the Midstream 50

One of the sector's largest publicly traded partnerships, Enterprise provides natural gas treating, processing, transportation and storage for gas and NGL. It has 145.2 million barrels (MMbbl) of storage capacity in Texas storage facilities, while its next–largest capacity is 15.4 MMbbl in Louisiana; it has total capacity from facilities across the nation of 178.3 MMbbl.

The company has large ownership interests in several crude oil pipelines across the U.S.

Seeking Alpha reported in the early fourth quarter that the company "has emerged from the 2015 oil crash with best-in-class assets firing on all cylinders [and] also has a best-in-class balance sheet [with units yielding] 6%."

The investor website also reported that Enterprise Products' second-quarter 2018 recap recounted "19.3 million tonnes per day of propylene were produced; 1.75 MMbbl/d of NGL, crude, petchem and refined products marine terminal volumes; 927 Mbbl/d of



An LNG tanker idles through the narrow Singapore Strait. Piracy is not what it once was on the high seas, but the narrow passageway still sees attacks on cargo vessels, mostly thefts of stores, despite the best efforts by Singapore and Indonesia. *Source: Shutterstock/Igor Grochev*

NGL fractionation volumes and 3.41 MMbbl/d of NGL pipeline transportation volumes"—all record amounts.

EPD reported record second-quarter results with EBITDA of $1.77 billion, up from $1.37 billion in second-quarter 2017.

Targa Resources

- **NYSE: TRGP**
- **Houston**
- **No. 12 on the Midstream 50**

Targa describes itself as "one of the largest independent midstream energy companies in North America." It gathers, treats and sells natural gas and provides a full range of services for NGL, crude oil and refined products across the Permian Basin, Barnett, Bakken and Eagle Ford shales, the Anadarko and Arkoma basins and onshore Louisiana and in the Gulf.

In September, the company reported that it planned to sell its refined products and crude oil storage and terminaling facilities in Tacoma, Wash., and Baltimore to an affiliate of ArcLight Capital Partners LLC for about $160 million.

Earlier in the year, Targa joined NextEra Energy Resources, WhiteWater Midstream and Marathon Petroleum's MPLX LP to develop the Whistler Pipeline project, "which will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast," it announced. The 450-mile-long pipeline will transport about 2 billion cubic feet per day of gas and could be operational in fourth-quarter 2020.

Energy Transfer LP

- **NYSE: ET**
- **Dallas**
- **No. 2 on the Midstream 50**

In one of the latest roll-ups within the sector, Energy Transfer Equity and Energy Transfer Partners completed their merger in October. The simplified entity is now operating as a single partnership known as Energy Transfer LP.

The merger helped streamline a complex organizational structure "and improve transparency for our investors. It also helps provide the new Energy Transfer with an improved cost of capital to more easily fund robust organic growth projects and to execute on strategic opportunities," the firm said following closure of the deal.

In September, ET joined Magellan Midstream Partners LP, and Delek US Holdings Inc. to construct the Permian Gulf Coast Pipeline, which would take crude oil from the Permian Basin to the Texas Gulf Coast.

"The 600-mile system is expected to be operational in mid-2020 with multiple Texas origins including Wink, Crane and Midland. The pipeline system will have the strategic capability to transport crude oil to both Energy Transfer's Nederland, Texas, terminal and Magellan's East Houston, Texas, terminal," a press release added. ■

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TAKE IT AWAY *(continued from page 5)*

the Nueces Header and Agua Dulce markets, as well as along an extension through Corpus Christi to the Houston Ship Channel.

But it's not all about the pipes. Cogent Midstream LLC's new lower Midland Basin refrigerated cryogenic processing plant—Big Lake II in Reagan County, Texas—will boast capacity of 200 million cubic feet per day (MMcf/d) when it opens in fourth-quarter 2019. The high-efficiency UOP Russell plant is capable of high recovery rates for NGL including ethane and propane.

Salt Creek Midstream LLC and Noble Midstream Partners LP have formed a 50:50 joint venture to build a pipeline and gathering system in the Delaware Basin. Construction is underway, with operations expected to begin in second-quarter 2019. The project will provide access to 200 Mbbl of new crude storage with the possibility to expand to 300 Mbbl.

Marcellus-Utica

Selected major projects in Appalachia are past the "getting started" phase and moving toward startup.

TransCanada Corp. received approval from the Federal Energy Regulatory Commission (FERC) to place part of its $900 million WB Xpress natural gas pipeline into service in West Virginia.

The Williams Cos. Inc. also gained FERC's OK in early October to put the $3 billion Atlantic Sunrise gas pipeline into service. The 1.7 Bcf/d line runs from Pennsylvania to South Carolina. ■

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Selected Recent Midstream Construction Projects

Operator/Developer	Project	Location	Added Capacity	Play	Status/Completion
Plains All American Pipeline LP	Sunrise Pipeline, Cactus II expansions	West Texas	500,000 bbl/d for Sunrise; 670,000 bbl/d for Cactus II	Permian Basin	Both pipelines will begin partial operations ahead of schedule.
EPIC Midstream Holdings LP	EPIC NGL Pipeline	Crane, Texas, to Corpus Christi, Texas	200,000 bbl/d	Permian Basin	Crude oil service to begin on EPIC NGL Pipeline during construction of EPIC Crude Oil Pipeline.
Cogent Midstream LLC	Big Lake II cryogenic gas processing plant	Reagan County, Texas	200 MMcf/d	Permian Basin	Cogent's Big Lake II will add capacity to its Big Lake Plant when it comes online in fourth-quarter 2019.
Contanda Terminals LLC	Contanda Houston Jacintoport Terminal	Houston Ship Channel	3 million barrels	N/A	Construction to begin in October 2018 with the petrochemical and hydrocarbon storage facility expected to be operational in fourth-quarter 2019.
Tallgrass Energy Partners LP	Seahorse Pipeline	Cushing, Okla., to Louisiana Gulf Coast	800,000 bbl/d	N/A	Open season launches on Aug. 15 for pipeline to St. James, La., and proposed Plaquemines Liquids Terminal.
Trafigura	Deepwater crude oil port	Near Corpus Christi, Texas	500,000 bbl/d	N/A	Plans announced to build offshore port capable of handling VLCCs with single-point mooring buoy system.
Energy Transfer Partners LP	Dakota Access Pipeline	North Dakota	100,000 bbl/d expansion	Williston Basin	Projected to come online by 2020.
Taproot Energy Partners LLC	Multiproduct midstream system	Weld County, Colo.	N/A	Denver-Julesburg Basin	Construction started on system that includes gas, oil and water gathering, gas treating and processing and freshwater supply.
Phillips 66 Partners	Grey Oak Pipeline	Three Rivers Terminal, Texas, to Corpus Christi, Texas	700,000 bbl/d	Eagle Ford	Open season for long-haul crude transportation began Sept. 27.
Aspen Midstream LLC	Pipeline, gas gathering system	Washington, Fayette and Burleson counties, along with portions of Austin, Brazos, Colorado and Waller counties, Texas	N/A	Austin Chalk	Residue pipeline and lean and rich gas gathering system are expected to be in service by third-quarter 2019.

Complete listings online

Source: Hart Energy


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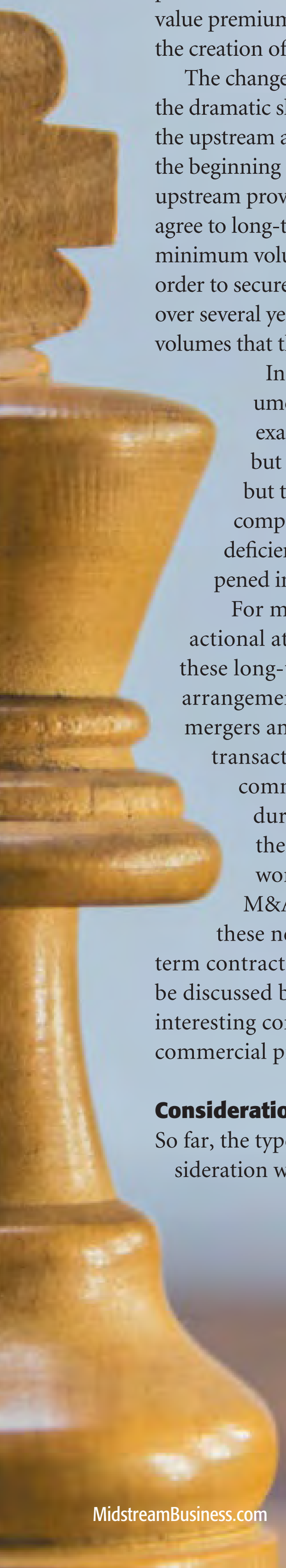
New Midstream Transactions

A changing midstream landscape has created new types of agreements with upstream producers.

By Peter Hays

A recent trend in the midstream and upstream oil and gas industry is for midstream service providers to offer certain forms of additional compensation to oil and gas lessees/operators—the upstream asset holders—in exchange for providing acreage dedications and entering into long-term service agreements. That can include mainly agreements for gathering, processing, transportation and the sale and marketing of hydrocarbons, as well as water sourcing and disposal services.



This additional compensation has taken different forms where the upstream entity can share in growth opportunities, including upfront cash payments, delayed cash payments, net profits interest, equity interests or other value premiums and, in certain cases, the creation of additional upside areas.

The change is interesting and reflects the dramatic shift in leverage between the upstream and the midstream from the beginning of the shale boom, where upstream providers would frequently agree to long-term, minimum payment/minimum volume arrangements in order to secure takeaway capacity over several years for the huge future volumes that they expected.

In many cases these volumes did not flow—for example, the Barnett Shale—but in certain cases they did, but too late for the upstream company to avoid punitive deficiency payments. That happened in the Haynesville Shale.

For many oil and gas transactional attorneys, working out these long-term, take-or-pay type arrangements filled the gap in mergers and acquisitions (M&A) transactional work caused by the commodity-price downturn during 2015. And now that the private-equity–fueled workout/Permian Basin M&A boom has leveled out, these new "pay-to-take" long-term contract transactions, which will be discussed below, have added an interesting component to oil and gas commercial practice.

Consideration structures

So far, the types of additional consideration we have seen a midstream services provider (Midstream Company) pay to an upstream operator (Upstream Company) in exchange for dedicating acreage for midstream services can include:

1. Cash payment—The most straightforward type is a cash payment by Midstream Company to Upstream Company in exchange for the dedication, based on a straightforward metric like dollar-per-net-acre dedicated or expected throughput.

2. Override—This is a grant by Midstream Company to Upstream Company of an interest in a certain percentage of the gross revenue received by Midstream Company from midstream services provided with respect to a certain agreed project area, without deduction for capital expenses or operating expenses.

3. Net profits interest after payout (NPI-Payout)—This is a grant by Midstream Company to Upstream Company of an interest in a certain percentage of the net revenue received by Midstream Company from midstream services provided with respect to the agreed project area, equivalent to gross revenue less certain delineated operating expenses and overhead expenses of Midstream Company, and subject to the further limitation of being payable only after Midstream Company's overall net revenue has reached a certain threshold payout number. The payout number is typically tied to capex of Midstream Company incurred to construct the gathering and processing system necessary to provide the relevant midstream services for the project area and can include a return on investment (ROI) factor.

4. Net profits interest with a carried interest (NPI–Carry)—In this arrangement, there is a grant by Midstream Company to Upstream Company of an interest in a certain percentage of the net revenue received by Midstream Company from the midstream services provided with respect to the agreed project area, equivalent to gross revenue less operating expenses and overhead expenses of Midstream Company, payable immediately without any payout threshold. In other words, the same as item No. 3, except without a payout threshold (or, put another way, similar to item No. 2, except with a deduction for operating expenses).

The effect here is that Upstream Company is effectively carried for the amount of the capex of Midstream Company incurred to construct the gathering and processing system necessary to provide the relevant midstream services. One alternative version is to fix the relevant carry amount so that if for some reason Midstream Company is required to incur capex in addition to such fixed amount, then Midstream Company would be entitled to a preferential payout until it recovered such additional capex costs (capex amount in excess of fixed carry amount).

5. Additional upside area—*With* respect to each form of additional consideration set out in items 2, 3 and 4 above, note that the relevant project area subject to the overriding royalty interest (ORRI) or NPI could be made to include acreage in addition to, or otherwise outside of, the project area subject to dedication, thereby giving the holder of the ORRI or NPI a potential upside benefit. In other words, Upstream Company would receive its ORRI or NPI from revenue relating to services provided by Midstream Company with respect to hydrocarbons produced from the project area subject to the dedication (the area covered by the Upstream Company's dedicated minerals/leases) plus revenue from services provided by Midstream Company with respect to third-party hydrocarbons produced from a wider, area of mutual interest-type area.

6. Regular equity in Midstream Company—There can be a grant by Midstream Company to Upstream Company of true equity (membership interests, common stock) in Midstream Company. Under this scenario, Midstream Company would probably be formed as a special-purpose vehicle set up to own a regionally discrete gathering and processing system. The parties will need to address obligations for capital costs, including those necessary to build out the system to Upstream Company.

Upstream Company may argue that the contribution of its acreage dedication should cover its share of those costs or a certain percentage of its share of those costs (including potentially 100% of its share plus a certain carry). If Midstream Company wants to avoid granting Upstream Company the types of rights that accompany a true equity interest, it may instead grant a contractual right that tracks equity interest (a "synthetic" or "tracking" equity interest), including potentially sharing upside upon exit at sale/IPO.

Some limitations

Note that the types of additional consideration set out above may be—and typically will be—conditioned in certain ways, including as to performance and timing. Certain limitations that we have seen include:

1. Paid immediately—This is not really a limitation but the most straightforward form, and presumably the most desirable, for Upstream Company, where the benefit to Upstream Company is paid, or vests or otherwise accrues, immediately and with no clawback effect.

These deals can be set up like an M&A transaction, where at "closing," delivery of consideration (cash, equity, etc.) occurs in exchange for execution of the midstream arrangements. Another benefit of this type of structure to Upstream Company is that it allows the consideration to be "taken off the table" going forward, so that it is not part of the valuation model upon a future divestiture of the upstream assets.

This additional compensation has taken different forms where the upstream entity can share in growth opportunities, including upfront cash payments, delayed cash payments, net profits interests, equity interests or other value premiums and … the creation of additional upside areas.

2. Payment tied to metric—This is a structure where the consideration paid to Upstream Company is tied to achieving certain metrics or hurdles. These metrics can be volumetric, such as hitting a certain cumulative throughput amount over time or reaching a certain daily throughput hurdle; or may be tied to a drilling program, where consideration is earned after a certain number of wells have been drilled in the dedicated area (calculation can be gross or net based on the dedicating party's interest).

A middle-of-the-road variation is where certain consideration is paid at dedication, but an additional hold-back payment is earned upon hitting a metric or hurdle.

3. Clawback—In this case, there is a structure where the consideration is paid to Upstream Party at dedication but a mechanism is in place whereby Midstream Company recoups some or all of the consideration in the event that certain metrics are *not* reached (volumetric or drilling), usually by a certain time deadline. Since recoupment of a cash payment is seldom assured, this "recoupment" is more likely to be tied to an NPI or equity/synthetic equity consideration structure, where the clawback results in Upstream Company's percentage interest being eliminated or otherwise reduced, or withered, for failure to hit applicable metrics.

Alternatively, the reduction of Upstream Company's interest could be triggered by Midstream Company hitting certain stretch goals in an equity consideration structure, most likely tied to third-party customers. In other words, Upstream Company's upside consideration is reduced or capped when Midstream Company reaches a certain volumetric hurdle with respect to third-party throughput.

Mineral owner structures

Certain additional types of structures that we have considered are worth noting here.

Reflecting the increasing likelihood that a mineral interest owner will be a commercial industry participant—an active investor in minerals such as a private-equity fund)—these are structures where a mineral interest owner (Mineral Owner), either as an owner of unleased mineral interests or as a lessor of mineral interests subject to an existing lease, would contract directly with Midstream Company to earn additional consideration in exchange for a dedication. These structures may include contingencies reflective of the current or eventual lessee (Upstream Operator).

The main principle at work with respect to these Mineral Owner structures is that, since an oil and gas lease is a property right that is derivative of the underlying mineral interest, any form of agreement that can be entered into by an oil and gas lessee can also be agreed to by a Mineral Owner. This is with respect to its arguably greater interest in the underlying minerals, and that any burden that is properly placed on unleased minerals that are then subsequently leased—including a dedication to a midstream services agreement—will continue to burden the lessee after it leases the minerals (the lease will be taken subject to the relevant dedication or other agreement).

A secondary principle relevant here is that the Mineral Owner typically retains certain rights with respect to minerals even after leasing, including the right to take its royalty interest share of production in kind. For example:

1. Mineral interest owner dedication (Pre-lease)—Under this structure, Mineral Owner dedicates its unleased minerals within a certain project area to Midstream Company, prior to leasing the minerals. Mineral Owner receives all relevant additional consideration in exchange for the dedication, which includes execution of the midstream services agreement, including all commercial terms typically contained within the relevant type of agreement.

One proviso is that the commercial terms of the midstream agreement should be sufficiently flexible to fit the development plans of one or more unknown, future Upstream Operators, in order to avoid an overly negative effect on the consideration paid to the Mineral Owner for the lease itself. In this case, fees are set based on a cost-of-service model, where per-million British thermal units gathering and processing fees are determined based on the amount necessary for Midstream Company to recover capex-plus-opex-plus-ROI over the relevant determination period may be appropriate, together with shipper optionality as to the type of midstream build-out, including options for a central delivery point-based model vs. well-based model, etc.

In either case, Midstream Company may agree to meet with prospective Upstream Operator-lessees in order to explain and, as necessary, modify service arrangements so as to lessen any negative impact on lease terms due to prior arrangements in place.

2. Preferential right on dedication of mineral interest—Mineral Owner grants to Midstream Company a package of primary actor rights—one of, or some combination of, a right of first negotiation, right of first refusal and/or preferential right—to gain the dedication of minerals within the unleased project area. These primary rights would be triggered when the Mineral Owner is approached by an Upstream Operator to lease minerals. As an example, primary rights offered to Midstream Company could include:

- Mineral Owner promises to give Midstream Company the opportunity to meet with Upstream Operator in order to win the business of Upstream Operator for midstream services for the applicable project area; and/or
- Upstream Operator would take its leases from Mineral Owner subject to Midstream Company's preferential right to match any offer by any third-party midstream provider for midstream services.

For the first item above, the arrangement could be limited to a contractual agreement between Midstream Company and Mineral Owner covering procedures around leasing applicable mineral packages. For the second item above, the arrangement could take either the form of a limited dedication of the relevant minerals that would burden the minerals with the right of first refusal (ROFR)/preferential right or a limited contractual agreement whereby Mineral Owner promises Midstream Company to include the ROFR/preferential right in the applicable leases.

In either case, the relevant burden on Upstream Operator would be set out in its lease from Mineral Owner. Since in this case the commercial terms of the midstream agreement would be negotiated directly with the Upstream Operator, the negative impact on leasing discussed above should be lessened considerably.

The additional consideration for dedication would most likely be paid by the Midstream Company to the Mineral Owner if and when the Midstream Company enters into a dedicated midstream services agreement with an Upstream Operator, although some nominal consideration could be earned upon the initial grant of the ROFR/preferential right. Arguably under either option, Mineral Owner and/or Midstream Company could be given the option to offer up a certain percentage of the overall additional consideration to Upstream Operator in order to increase the likelihood of capturing the midstream business.

3. Lessor dedication—Under this structure, the applicable mineral interests are already subject to a lease with an Upstream Operator, and Midstream Company would potentially already have an arrangement in place with Upstream Operator for midstream services. Mineral Owner would dedicate its royalty interest (RI) production to the Midstream Company pursuant to its take-in-kind rights, in exchange for additional consideration. This type of grant is most likely available in the case where the Mineral Owner has some optionality for sending its RI production to another third-party midstream company.

In this scenario, Mineral Owner has leverage to pick up a quick payday in exchange for granting to Midstream Company rights to the RI production that Midstream Company may already be counting on receiving. Alternatively, Mineral Owner could seek compensation from Upstream Operator, in a situation where Upstream Operator needs RI volumes in order to meet its take-or-pay or minimum volume commitments under existing arrangements with Midstream Company. ■

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