The glut in the Gulf

Mark Le Dain, Validere, Canada, explores the data dynamics driving crude storage and infrastructure expansion in the Gulf region.

Reported US crude storage has remained persistently high over the past year. This is despite co-ordinated efforts to draw it down by OPEC, combined with natural and then sanction-related declines from many of the major US suppliers. Reduced global demand was certainly a factor in additions, but storage levels have likely been exacerbated by two recent structural changes that the market will take time to factor into estimates and commentary. The changes are the increased presence of condensate in major streams – specifically plant condensate, which is not counted as crude – and the steady increase in line fill from the recent energy infrastructure buildout across the country. Line fill is crude that is visible in the storage numbers and continues to make up a greater percentage, but is not available to be consumed. At the same time, condensate entering crude streams is suggesting crude production is higher than it actually is due to the reclassification as crude. These two factors, detailed further in this article, suggest tighter crude markets than implied by looking at current storage levels vs a five-year average.

Infrastructure additions and the impact on storage numbers

The significant growth in crude production over the past few years has resulted in a wave of new infrastructure, with production growing from 6 million bpd in 2012 to just under 13 million bpd recently. Approving the export of crude from the US also meant that significant infrastructure was required in terms of storage, pipelines, and export terminals to facilitate the movement of crude to international buyers. It seems that this will only continue, with several new export projects currently proposed, and some already reaching final investment decisions on US deepwater ports.

New pipelines and reversals of existing pipelines originating in the Midwest are increasing the movement of crude oil south to the Gulf Coast to support this import to export shift. As a result of this increase, the Gulf Coast has transitioned from being a net shipper to a net recipient of crude oil from elsewhere in the country, which in some areas created a duplicating of infrastructure in a short period of time. Pipeline infrastructure continues to be added to support these changes, with another 3 million bpd of planned capacity additions in 2020 and approximately 1.75 million bpd expected in 2021. Growing production combined with export changes

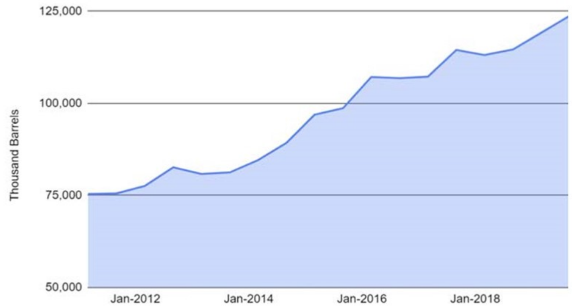

Figure 1. **Pipeline fill and transit by water and rail.**

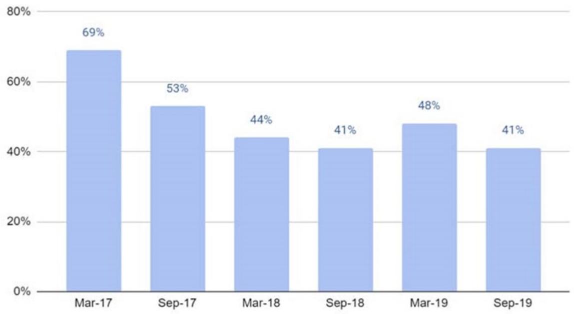

Figure 2. **Tank utilisation rate.**

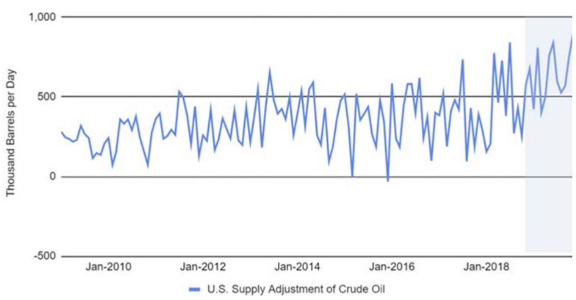

Figure 3. **Energy Information Administration adjustment over time.**

continues to require additional liquids infrastructure, and this has not yet stopped, although it appears to be slowing.

The majority of this infrastructure buildout has been focused in the Permian Basin. Midstream companies recently completed several new Permian projects, such as Plains All American Pipeline's Cactus II, to help clear the transportation bottleneck to the Gulf Coast. As these new pipelines come online the operator commences with line fill, where the pipeline is filled with oil before commercial deliveries can begin. This line fill is product that is required for the pipeline to operate, but since the pipeline is not going to be drawn down while in operation this product could never actually meet consumer demand if needed. It sounds small to think of a couple of million barrels in a pipeline that the market cannot access, but if this is multiplied over a significant infrastructure buildout to meet both imports and exports, it adds up. All this recent line fill shows up in storage, and these numbers have recently almost doubled. This means less available useful crude as a percentage of total crude vs historical periods. It takes time to recognise this new shift, that there is less crude available despite headline numbers, due to the backward-looking comparison of crude storage numbers.

A similar data problem occurs with storage tanks, where most of the crude is held but a certain portion remains inaccessible. Minimum operational volumes for tanks are often referenced at 10%, but operators will likely view an active minimum at closer to 15% or 20%. This means these volumes are never accessible, and as volumes approach these levels operators will typically aim to pull volumes to these assets. If capacity is high across US tank storage this matters less, but as tank utilisation declines it means that a greater percentage is not accessible, regardless of total volume. This capacity utilisation rate across US tanks has been declining (from 70% utilisation in 2017 to 41% in 2019), which means that many tanks are closer to their minimum functional capacity than they have been historically. As the minimum operational level makes up a greater percentage of the crude volumes in storage it means that less crude is commercially available. Both these line fill and tank storage trends suggest a tighter market.

One of the places that remained a persistent addition of crude over the past year was the adjustment factor. Inventory data is driven by a clear relationship: production + imports = refinery inputs + exports + stocks change. This covers the way crude can enter and exit the system and the potential ways it can be consumed. Survey data is used to estimate these numbers, and since small timing and accuracy discrepancies always exist, an adjustment factor is used to balance the results – which usually averages out appropriately over time. This adjustment factor has averaged approximately 200 000 bpd historically, but has recently increased. When this factor goes in one direction and for an extended period of time, it can create market uncertainty as market participants wonder how all these additional barrels are getting into the system.

The biggest concerns are that demand is weaker than expected or supply/production is much larger than estimated, and as a result a large adjustment factor will typically put downwards pressure on crude prices. This is what occurred during 2019, as a steady addition of unexpected crude was present in each report. One of the potential causes of this is extracted condensate entering the stream, due to how these volumes are tracked. This was a trend that was already occurring, because of the lighter nature of US shale, but Venezuelan sanctions may have increased the impact.

Changing supply dynamics impacting product quality

Venezuela is home to the largest oil reserves in the world, and the crude has an average API gravity of less than 20˚, making Venezuela's conventional crude oil heavy by international standards. Venezuelan production had already been in decline due to local strife, and in January 2019, the US imposed sanctions on Venezuela which accelerated these declines. Most of the commentary around these sanctions suggested that Venezuela could no longer export crude to the US, as Gulf Coast refiners were historically a major buyer of Venezuelan crude. A less covered result of the sanctions was that oil and petroleum products produced in the US could no longer be exported to Venezuela. Most of the products Venezuela received from the US were for blending with the heavier production from Venezuela for processing purposes. Specifically, condensate or other light oils are used to blend with the heavy before the oil is sent by pipeline to domestic refineries, export terminals or upgraders to help facilitate transport.

In addition, if the native heavy crude cannot be upgraded, which has occurred often lately due to facility failures, it is simply mixed with lighter product and exported. After the sanctions, Petróleos de Venezuela, S.A. has had trouble finding another source for diluent, and has been forced to use the small amount of light crude that it has for blending. Venezuela's crude oil production has steadily declined, and an abundance of lighter product in the Gulf Coast is a likely repercussion of the sanctions. These US volumes, that were previously exported to Venezuela and either consumed or then sent to other buyers globally, are now trapped in the US.

The nuance with condensate is that if it is extracted from a processing plant, it is not included in crude production volumes by the Energy Information Administration (EIA). With the lighter nature of shale plays there was already an abundance of this product in the US looking for markets. The loss of a key market for this product, such as Venezuela, puts pressure on pricing and forces suppliers to look for other options. One of these options, particularly driven by the pricing pressure, is to blend this condensate into local crude streams. Depending on the source of the condensate this would be the first place these volumes show up for the EIA storage reports. Evidence of this trend is potentially found in the visible jump in the gravity of the PADD 3 quality stream, and the fact that local storage levels reached their peak following the announcement of the Venezuelan sanctions. While the impact cannot yet be qualified, this seems like a plausible cause for the increased appearance of barrels in storage during 2019 through the adjustment factor. These two factors indicate a tighter market for usable crude than currently suggested by the headline numbers.