Why Crude by Rail Isn't Picking Up the Slack

Lack of tank cars and railroad hesitancy limit shipper options.

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Data Sources for This Publication
U.S. Energy Information Administration
CME Group
To discover more about the data sources used, click here.

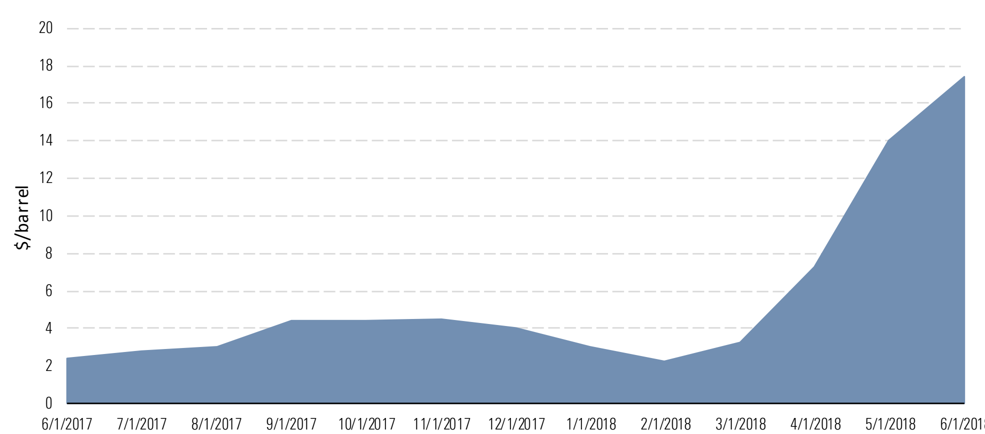
Plugging the Gap

Crude production in the largest onshore U.S. basin and in western Canada is growing faster than pipeline takeaway capacity, causing congestion and price discounts. During the first shale boom between 2011 and 2013, similar congestion and discounts led shippers to use rail to bypass the logjams and get crude to market. This year, although rail shipments are up and opportunities abound for crude by rail, even in less congested shale plays like the North Dakota Bakken, the railroads have so far taken little advantage of these opportunities. This note details why rail hasn't plugged the gap in pipeline takeaway capacity this time around.

Permian

Permian crude production in West Texas is expected to reach nearly 3.3 million barrels per day this month (June 2018), according to the U.S. Energy Information Administration's Drilling Productivity Report, and is growing by about 75 thousand barrels/day every month. Recent wide differentials between prices at the Midland, Texas, production hub and the Houston market averaged $15/barrel from May 1 to June 13, 2018, reflecting growing pipeline congestion out of the basin (Exhibit 1). New pipeline capacity is not expected on line until the second half of 2019. In the meantime, higher discounts reflect higher freight costs for alternative crude transportation, such as rail and truck. Typical tariffs to Gulf Coast markets on long-distance pipelines are about $3/barrel, while rail transport costs are about $10/barrel and sending crude all the way by truck costs at least $12/barrel.

Exhibit 1 Premium for WTI Houston Over WTI Midland



Source: CME Group, Morningstar

Western Canada

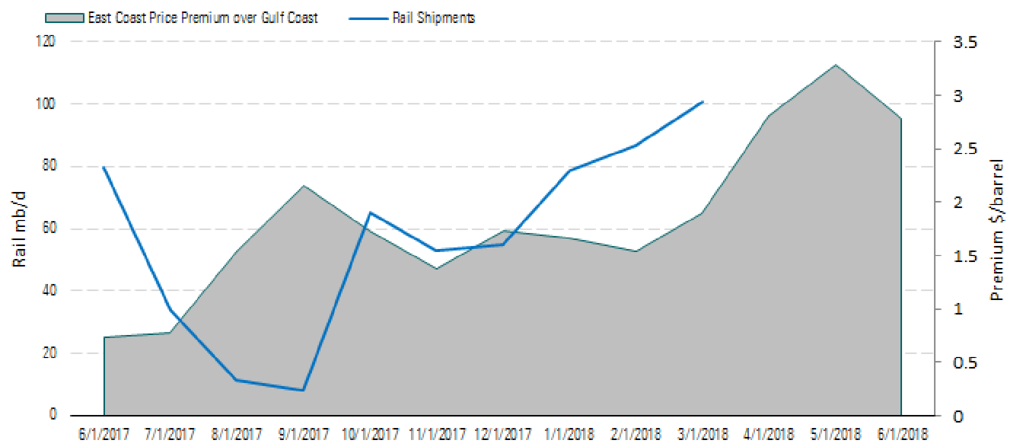
The Canadian Association of Petroleum Producers' annual crude forecast, released this month, shows western Canadian production increasing by 358 thousand barrels/day to 4.3 mmb/d in 2018 and by another 166 mb/d during 2019. The U.S. is the only export market for 99% of western Canadian crude above Canadian refinery demand of about 1.0 mmb/d. Current available crude pipeline capacity across the U.S.-Canada border is estimated by CAPP to be 3.3 mmb/d, which exactly matches shipper demand today. In practice, operational constraints mean that these pipelines are apportioned such that shippers need to find alternative transport for most of their incremental production. That means Canadian crude in Alberta is typically discounted heavily against the U.S. benchmark West Texas Intermediate, and those discounts have been growing recently, reaching an average $26/barrel during the first quarter of 2018. Just as we are seeing now in the Permian, the size of Canadian crude discounts reflects higher freight costs to ship crude to the U.S. by rail.

Our analysis in January 2018 (see "Can Rail Handle Canadian Crude?") indicated spare rail load capacity in Alberta and assessed that rolling stock appeared to be adequate to meet increased demand for crude by rail in Canada. However, rail volumes have not increased as rapidly as expected, given the widening crude discounts. Crude-by-rail shipments to the U.S. from western Canada averaged 170 mb/d in March 2018, according to Canada's National Energy Board—up just 20 mb/d since December 2017 despite higher crude output and consistent pipeline congestion.

North Dakota

We last looked at crude takeaway from North Dakota's Bakken shale in a February note (see "Should DAPL Producers Have Stayed on the Rails?"). At that time, we noted that, unlike 2014 when pipelines out of North Dakota could not accommodate growing production, Bakken shippers now enjoy access to the 520 mb/d Dakota Access pipeline, or DAPL, which came on line in June 2017, providing service to Patoka, Illinois, and Nederland, Texas, on the Gulf Coast. Including DAPL, the North Dakota Pipeline Authority estimates that the state has 1.28 mmb/d of pipeline takeaway capacity, more than adequate to ship the latest EIA Bakken production estimate for June 2018 of 1.24 mmb/d after considering local refining (88 mb/d) and regular rail shipments to West Coast refineries of 136 mb/d. However, as we pointed out in February, our analysis of price differentials indicates that Bakken shippers would likely be better off sending crude by rail to refineries on the East Coast instead of using DAPL to ship crude to Patoka or Nederland. That's because a widening premium over WTI has made East Coast crude prices based on Brent more attractive than Gulf Coast prices based on Houston WTI. Exhibit 2 shows the monthly average East Coast Brent premium to WTI Houston over the past year (gray shading, left axis) and the level of rail shipments from North Dakota to East Coast refineries through March 2018—the latest available data from the EIA (blue line, right axis).

Exhibit 2 Brent Premium to WTI Houston and Rail Shipments to East Coast



Source: EIA, CME Group, Morningstar

East Coast rail shipments have recovered this year from a low of 8 mb/d in September 2017 to 101 mb/d in March 2018, but they haven't come close to their historical peak of 450 mb/d in November 2014. Despite price differentials being favorable since the fall of 2017 and growing wider since March 2018, North Dakota rail shipments do not appear to have increased significantly. In February, we attributed this reluctance to ship by rail to the fact that shippers were committed to DAPL and would have to pay take-or-pay fees if they switched from the pipeline to rail, and this is still true for long-term committed shippers. However, shippers uncommitted to DAPL or other pipelines could switch to rail with no penalty, but despite improving economics, they do not appear to be doing so.

We identified three reasons railroads aren't picking up the slack in crude shipments in the Permian, western Canada or North Dakota, despite the apparent economic incentives. We detail each of these below.

Lack of Rolling Stock

Although crude-by-rail volumes are down significantly in 2018 from the heyday of 2013, the fleet has shrunk considerably as a result of legislation to remove older designs following a slew of accidents between 2012 and 2015 as rail shipments climbed. Subsequent legislation in Canada and the U.S. required phasing out a large part of the rail tank car fleet built to older standards by the end of 2017. Our analysis in January (see "Can Rail Handle Canadian Crude?") indicated that there were roughly 13,000 rail tank cars available for crude oil use this year based on Department of Transportation estimates in July 2017. What we didn't factor in back then was that about 8,000 of those tank cars were CPC 1232 cars, an older design that is being phased out for crude use by April 2020. It now appears that railroads are reluctant to use these tank cars to ship crude today and in some cases, they are penalizing their use by a surcharge. These actions have effectively starved both U.S and Canadian railroads of the rolling stock needed to crank up crude-by-rail shipments. In many cases, railroads are effectively limited to a much smaller fleet of new DOT 117 design tank cars that have only been available since 2015.

Railroads Reluctant to Make Short-Term Deals

Railroads don't want short-term crude-by-rail business and are demanding that customers commit to long-term shipments with take-or-pay agreements before they move crude. Unlike the early shale years when railroad companies were lining up for crude business, they have become more savvy and reluctant to invest without longer-term returns. They are therefore imposing restrictions such as minimum-term contracts, the use of dedicated unit trains and higher freight rates to absorb market price differentials. These contractual requirements are also affecting Canadian crude-by-rail shipments.

Permian Terminal Capacity Shortage

Crude by rail never really took off in the Permian during the first shale boom because there was limited pipeline congestion in the basin. Existing load terminals built in West Texas are therefore ill-prepared for service now that they are urgently needed. Most terminals that were constructed in 2013-15 were used to deliver drilling and fracking supplies rather than for crude takeaway. Project plans to build out crude storage in order to load dedicated 100-car unit trains were shelved when prices collapsed in 2015 and drilling came to a standstill. Building out terminals today will take time, and Permian congestion already has an end date when new pipelines are expected on line in late 2019. That window is too narrow to make crude-by-rail investment pay off apart from expanding existing terminals.

Market Impact

The market impact of these rail constraints will be higher discounts for crude stranded in western Canada and the Permian until new pipelines bring relief. That relief is expected in the Permian by the end of 2019, but for Canadian producers, the pain could last longer as permit approval delays appear to be never-ending. The Canadian federal government's recent purchase of Kinder Morgan's Trans Mountain pipeline and its expansion project could bring relief by 2020 but will still not guarantee smooth sailing past hostile opposition in British Columbia. The main losers from the rail constraints in the Bakken are refiners on the East Coast that could benefit from cheaper crude delivered by rail. As price discounts expand, we expect new rail schemes will emerge to exploit the arbitrage in the Permian and western Canada, but the pain is likely to get worse before then. M

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