Mixed Lockdown Results for Canadian Crude

Producers benefit but Midwest margins narrow.

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Data Sources for This Publication
EIA
CME Group
AER
CER

To discover more about the data sources used, click here.

Pipeline Constraints Evaporate

An Oil Sands Magazine study this March showed overall United States crude imports declining steadily since 2005 to average 6.9 million barrels/day in 2019, while imports from Canada increased to almost 4 mmb/d by the end of 2019. The study estimates demand for Canadian crude makes up 22% of total U.S. feedstock. Despite this robust demand, pipeline build-out challenges have plagued supply routes for years, leading to congestion and price discounts. Then the coronavirus pandemic struck—destroying oil demand and battering prices in April—reducing crude imports from Canada by an average 1.3 mmb/d during the second quarter of 2020. The result was production curtailment and rising inventory in Western Canada but also a price recovery of sorts as pipeline constraints evaporated. This note reviews the impacts of the lockdown on Canadian crude prospects.

Production and Pipelines

As we detailed in a July 2019 note (see Canadian Crude Production Fails Earlier Promise) most Canadian production is heavier crude from the Western Canadian Sedimentary Basin. This includes conventional medium and heavy crude recovered through drilling in Alberta and Saskatchewan as well as oil sands bitumen recovered from the Athabasca, Peace River, and Cold Lake deposits in northern Alberta. Oil sands bitumen is heavy and viscous crude either mined at the surface and upgraded into lighter grades or extracted in situ using thermal technologies. Bitumen crude is typically diluted with lighter hydrocarbons to facilitate flow to market in pipelines.

According to the Canadian Energy Regulator, crude production peaked at 4.9mmb/d in December 2019. Output north of the border has continually run up against pipeline capacity constraints with average exports of 3.7 mmb/d in 2019 vying for space on congested pipelines that mostly run across the U.S. border to feed refineries in the Midwest and Rockies. This congestion was reduced in 2019 after Alberta's provincial government-imposed proration to counter rising discounts for Canadian benchmark Western Canadian Select crude. Production limits successfully supported prices but were relaxed at the end of 2019 when unlimited rail shipments were permitted (see our January note Rail Operators Plan Canadian Diluent Recovery).

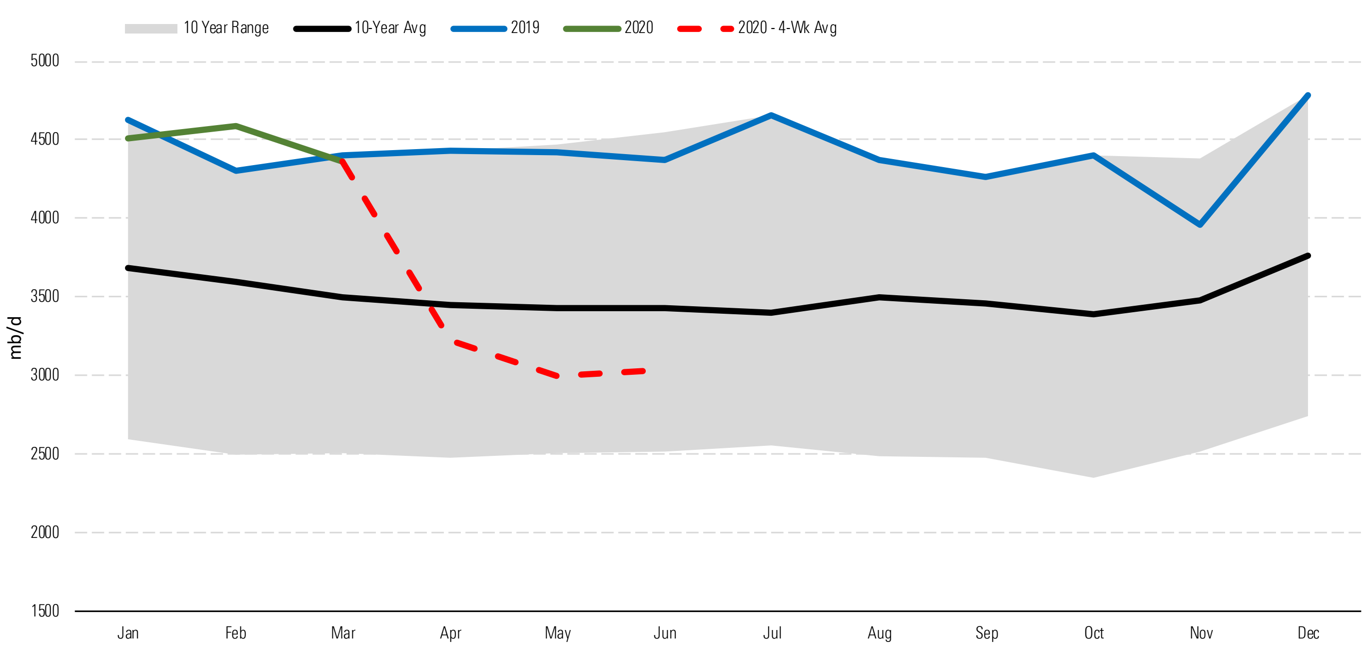
Perilous Prices

This year's pandemic saw WCS prices plunge to uncharted depths below $5/barrel in Hardisty, Alberta on March 30 and negative territory following the collapse of the CME Nymex May 2020 West Texas Intermediate crude contract at the end of April. These perilous prices and the demand destruction caused by the COVID-19 lockdown forced Canadian producers to curtail production quickly to stem their losses. Anecdotal estimates based on company announcements put Canadian crude curtailments as high as 1 mmb/d since April. The Alberta Energy Regulator's production reports indicate the province's output declined by 0.5 mmb/d from 3.6 mmb/d in March to 3.1 mmb/d in April. Even these dramatic reductions couldn't balance the loss of demand and AER monthly crude inventory increased by 3.7 million barrels as Alberta's crude exports dropped by 640 mb/d during April.

Imports Tumble

On the demand side, the virtual shutdown of U.S. transportation in April reduced the refiner's need for Canadian crude–particularly in the Midwest where 70% of supply comes from Western Canada. Data from the U.S. Energy Information Administration shows total imports of crude from Canada fell by an average 1.3 mmb/d during April, May and June (Exhibit 1). The EIA estimates Canadian imports averaged 3.8 mmb/d during 2019 and 4.5 mmb/d during the first quarter of 2020. Weekly EIA data shows that four-week average imports declined by 29% over March levels to just over 3.0 mmb/d in the week ending June 19. The import collapse reflected refiners lowering their crude throughput both to keep the lid on swelling product inventories and reduce losses from falling prices. Weekly EIA data shows Midwest refiners in the Petroleum Administration for Defense II region cut crude runs by 22% from an average 3.7 mmb/d in February to 2.9 mmb/d in April and were still only processing 3.2 mmb/d during the four-week period ending June 19 or 385 mb/d below 10-year average levels.

Exhibit 1 Seasonal U.S.-Canadian Crude Imports



Source: EIA, Morningstar.

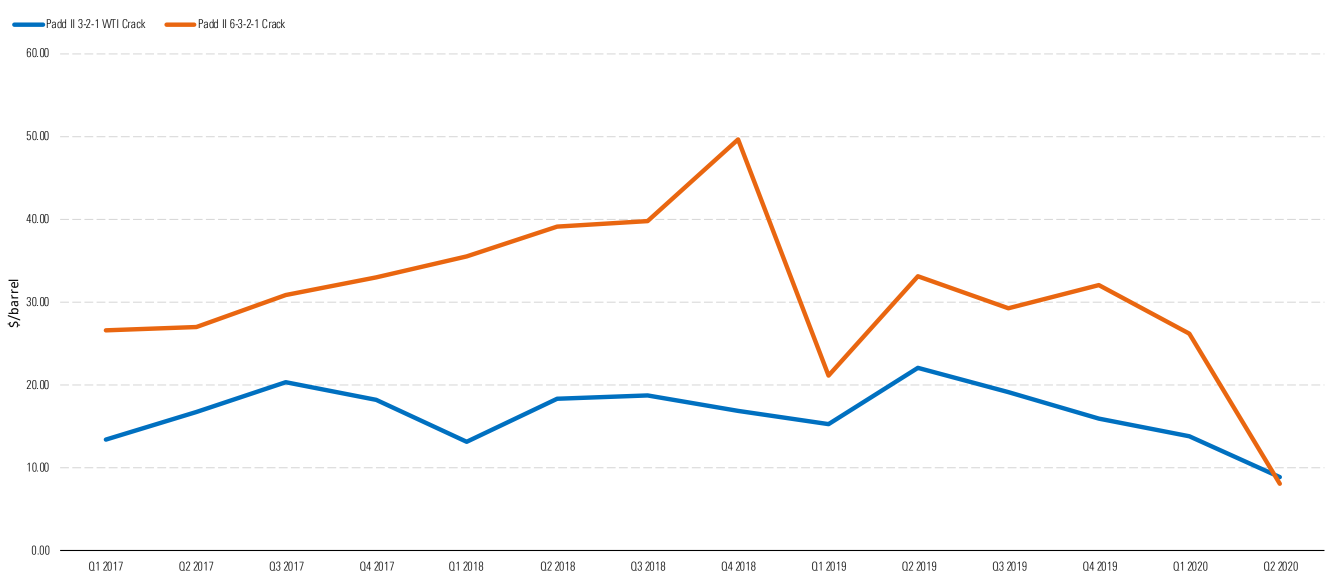
Discounts Narrow

There was some upside for WCS prices from the curtailment, which ended pipeline congestion out of Canada. With production down by as much as 1 mmb/d and U.S. imports down 1.3 mmb/d there was suddenly more than enough pipeline capacity to meet shippers' needs. That reduced discounts for Canadian crude to lows not seen since wildfires disrupted oil sands production in 2016. Discounts for WSC in Alberta versus WTI delivered to Cushing, Oklahoma averaged a whopping $26.6/barrel in 2018, falling to $13.8/barrel in 2019 after Alberta introduced proration. During the first quarter of 2020 the WCS discounts widened to average $17.9/barrel but then nearly halved to an average $9.6/barrel during the second quarter. Absolute WCS prices recovered to average $29.8/barrel in June (through June 23), slightly above their level in the first quarter of 2020 when discounts were higher, providing a ray of sunshine to battered Canadian producers.

Refining Margins

Unfortunately, that ray of sunshine wasn't shared by U.S. refiners. That's because lower WCS discounts made Canadian crude expensive relative to domestic alternatives like WTI. Our analysis shows higher prices for WCS lowered refining margins for processing Canadian crude in the Midwest during the second quarter relative to processing domestic alternative WTI. Exhibit 2 shows quarterly crack spreads for WTI and WCS in PADD II since the beginning of 2017. The cracks are calculated using EIA data for crude and refined product prices through March 2020 and then estimated for the second quarter based on CME Group data. The WTI margin is a 3-2-1 crack calculation based on producing two barrels of gasoline and one barrel of diesel for every three barrels of crude. The WCS margin is a 6-3-2-1 crack reflecting the heavier Canadian grade that produces a barrel of fuel oil as well as three barrels of gasoline and two barrels of diesel for every six barrels of crude.

Exhibit 2 Quarterly Average PADD II Crack Spreads



Source: EIA, CME Group, Morningstar.

The PADD II 3-2-1 crack for WTI averaged $18.07/bbl in 2019 and $13.74 in quarter one 2020–far lower than the 6-3-2-1 crack for processing heavily discounted Canadian crude that averaged $28.89/bbl in 2019 and $26.26 in first-quarter 2020. Similar outsize margins for processing Canadian crude have underwritten growing demand in the Midwest–incentivizing new output in Alberta even as producers swallowed big price discounts caused by congestion. Unfortunately, when those discounts narrowed in the second quarter, refining margins collapsed to an average $8.11/barrel–about 9% below the 3-2-1 WTI crack that averaged $8.90/barrel. In other words, with the transport constraints and discounts removed, Midwest refiners were no longer heavily incentivized to process Canadian crude.

Recovery

While the lockdown experience is arguably unique, the resulting easing of transport constraints holds bad omens for the future of Western Canadian crude output. If it's true that Canadian heavy crude isn't competitive in the Midwest–its largest market–unless prices are heavily discounted–then future investment in oil sands projects is harder to justify.

That theory will be tested for real in the next two years if one or all of three long-running pipeline projects out of Canada overcome environmental and political objections to finally end the capacity congestion that was temporarily lifted by the COVID-19 lockdown. The first of these projects, the Enbridge Line 3 expansion will add 390 mb/d capacity as soon as early 2021and the second–an expansion of the Canadian government-owned Trans Mountain pipeline from Edmonton, Alberta to Vancouver, British Columbia–will add 590 mb/d by the end of 2022. The third project is the 830 mb/d TC Energy Keystone XL project that reached a final investment decision in March and is expected online in 2023. All three together potentially add 1.8 mmb/d of new capacity out of Western Canada and end pipeline congestion for the foreseeable future.

Normal Pattern

If U.S. demand for petroleum products returns to a normal pattern next year then it's conceivable demand for Canadian crude bids up prices further in the Midwest. That would be the case if Canadian producers don't reverse all of the production curtailments caused by lower prices this year. The result would be a shortage of the heavy crude that most Midwest refineries favor, incentivizing them to process cheaper domestic barrels instead. If that happens, Canadian producers can sell surplus crude to the larger refining market in the Gulf Coast region, but will probably have to wait for competitive transport costs provided by the new pipelines to expand their share of that market.

Viability

However quickly production recovers, the recent lockdown experience casts doubt on the long-term viability of investment in Western Canadian crude. Although output has expanded consistently in the past decade in response to growing demand, big returns have nearly always eluded Canadian producers because of discounts caused by pipeline congestion. If it turns out that fixing the congestion pushes prices higher only to encourage U.S. refiners to process cheaper domestic alternatives, then big returns may never come to fruition, since Canadian producers will always have to discount their prices to compete. Investment viability is therefore tied to the price levels achieved after those discounts and whether they cover the costs and risks of production so far from refinery markets.

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