Canadian Crude Production Fails Earlier Promise

Takeaway capacity limits expansion plans.

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Sandy Fielden
Director, Oil and Products Research
+1 512 431-8044
sandy.fielden@morningstar.com

Data Sources for This Publication
Canadian Assn. of Petroleum Producers
EIA
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To discover more about the data sources used, click here.

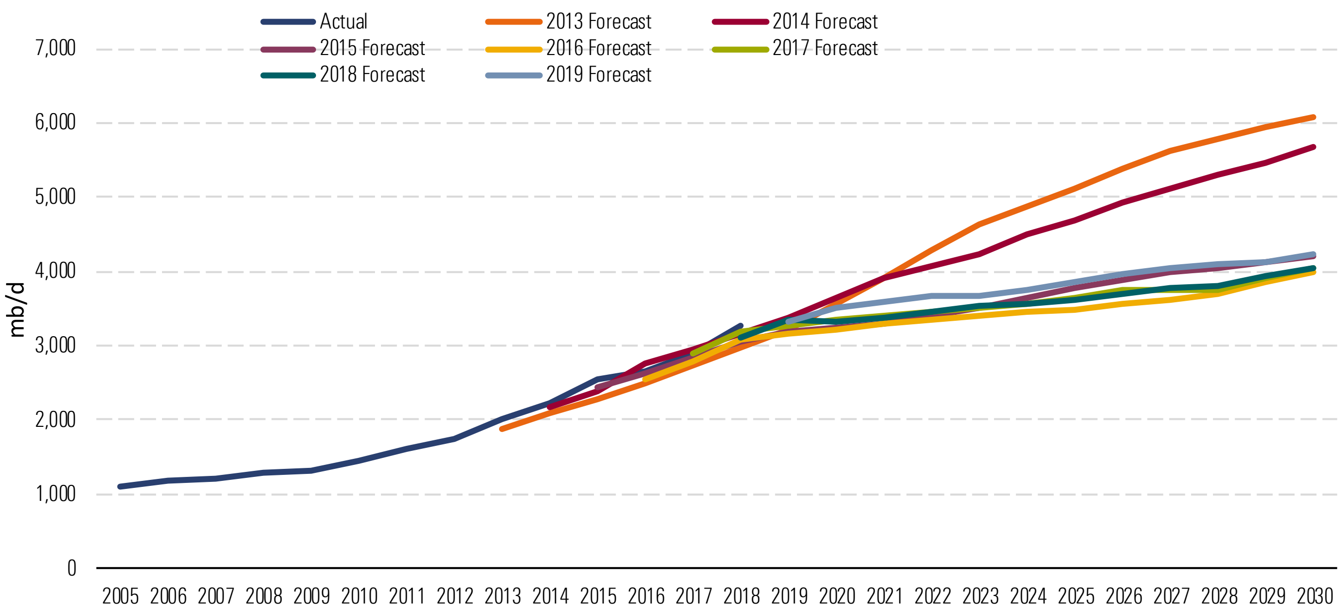
Investment Decline

In its latest June 2019 annual Crude Oil Forecast, Markets and Transportation review, the Canadian Association of Petroleum Producers cut its annual production growth forecast to just 1.4% for 2019. CAPP expects Canadian output to reach 5.7 million barrels/day by 2030, up from 4.3 mmb/d this year. By contrast, the organization's 2013 forecast expected output to reach 4.9 mmb/d by 2019 and 6.7 mmb/d in 2030. Between these two forecasts, despite strong demand for heavy Canadian crude in the United States and Asia, a series of pipeline takeaway constraints and regulatory hurdles have beset the industry's expansion plans. As a result, capital investment in the Canadian oil patch is expected to fall to $37 billion this year, well below its 2014 high of $81 billion. This note reviews diminished prospects for Canadian crude production.

Shrinking Forecast

Since the 1980s, the engine of Canadian production growth has been 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. CAPP estimates that the supply of medium and heavy crude from the WCSB increased threefold, from an annual average 1.1 mmb/d in 2005 to 3.3 mmb/d in 2018, with most of that increase coming since 2011, including a record 13% during 2018. Looking back, however, the evolution of CAPP's annual outlooks show far more bullish expectations in 2013, when it forecast WCSB heavy crude would grow to over 6 mmb/d by 2030. Those expectations have since shrunk to 4.2 mmb/d by the end of the next decade (Exhibit 1).

Exhibit 1 WCSB Heavy Crude Supply Forecast Evolution



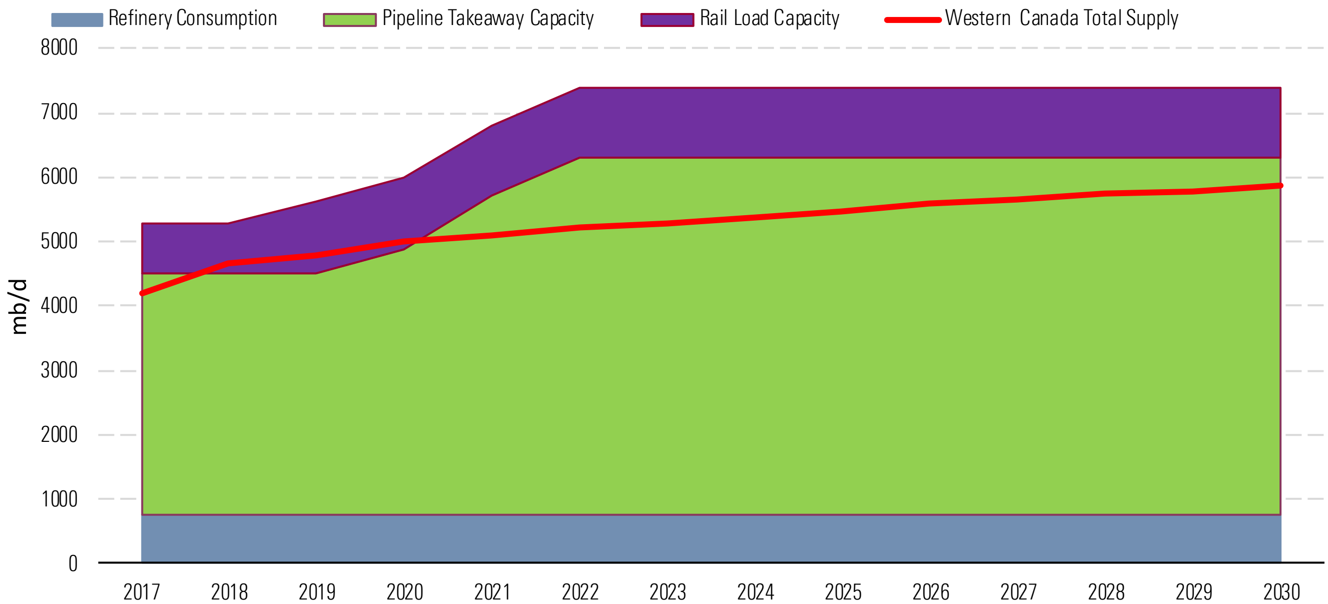
Source: CAPP, Morningstar.

Transport Limits

The slowdown in Canadian crude production prospects is almost entirely due to growing transport constraints getting crude out of Western Canada to export markets. CAPP estimate total Western Canadian crude supply in 2018 to have averaged 4.7 mmb/d, of which 0.75 mmb/d was processed by regional refineries, leaving just under 4.0 mmb/d of crude in search of takeaway capacity to Eastern Canada or U.S. refineries to the south. Current pipeline capacity out of the region is about 3.8 mmb/d on paper, although usable capacity is thought to be closer to 3.4 mmb/d. That left about 600 mb/d of crude needing to find an alternative route in 2018. For the most part, that meant using rail, which is more expensive than pipelines and subject to its own constraints in terms of lease arrangements and tank car availability, as we detailed in a January 2018 note (Can Rail Handle Canadian Crude?). Although there is 1.1 mmb/d of crude rail loading capacity in Western Canada, only an average 233 mb/d was shipped that way in 2018.

The takeaway stack out of Western Canada is shown in Exhibit 2. The gray shaded area represents refinery consumption and the green is total pipeline capacity. The purple shading is rail load capacity and the red line is total crude supply. Supply exceeded pipeline capacity in 2018 and looks to continue doing so in 2019 and 2020. Future relief relies on new pipelines out of the region, which we'll discuss later. The tight supply position creates pipeline congestion, building local inventories and increasing discounts for Canadian crude to levels supporting the higher cost of rail transport. When transport capacity gets particularly tight, discounts blow out to extreme levels as shippers compete for space on crowded pipelines. The level of discounts was higher than usual in 2018, averaging $27/barrel compared with $12/barrel in 2017.

Exhibit 2 Western Canadian Crude Takeaway Capacity and Supply



Source: CAPP, Morningstar.

Intervention

When U.S. crude prices collapsed in the final quarter of 2018 at the same time that Canadian crude discounts to the U.S. market were increasing, the Alberta provincial government intervened to stabilize prices by mandating production cuts. Announced on Dec. 2, the cuts lowered production by 325 mb/d, or 8.7% from January 2019 for three months, dropping to 95 mb/d until the end of 2019. The cuts had the desired effect of raising crude prices by narrowing discounts, but ironically priced Canadian rail barrels out of the market during the first quarter of 2019 (see our April note, East Coast Refiners Lose Canadian Heavy Card). Although the production cuts have been successful in reducing discounts that occur when producers compete for transportation, they discourage industry investment by producers and don't relieve pipeline congestion that can only be solved by new construction.

Pipeline Battles

New pipeline projects have been limited by lengthy permitting battles that have slowed the build-out of new capacity. Three pipeline expansions are currently awaiting final approval. The most advanced is the Enbridge Line 3 replacement, a rebuild project that will add 370 mb/d to the pipeline's capacity that is part of the Enbridge Mainline system. Line 3 replacement is awaiting final approval for a route through Minnesota, but a further delay in that permit this year has pushed completion to 2020 at the earliest. A second pipeline expansion is the Trans Mountain Expansion, or TMX, which was purchased from Kinder Morgan by the Canadian government in 2018 to ensure that the project is completed. That expansion, adding 590 mb/d capacity to the West Coast, was finally approved to proceed by Ottawa in June, but it must still be approved by the Supreme Court and faces hurdles in British Columbia that could delay it until 2022. Finally, the TransCanada Keystone XL is a new pipeline between Hardisty, Alberta, and the

Gulf Coast. The 830 mb/d Keystone XL was delayed for several years by the need to obtain a U.S. presidential border-crossing permit that was finally granted by the Trump administration in 2016 and replaced with a new version earlier this year. The project still faces delays in Nebraska permitting and is currently expected on line in 2021. These new pipelines will together alleviate crude takeaway congestion out of Alberta between 2020 and 2022, as can be seen in Exhibit 2.

Crude producers are not out of the woods, however, amid a polarizing debate in Canada over pipeline construction. What proponents regard as necessary conduits to realize the benefits of domestic crude production, opponents vilify as enablers of global warming and pollution. Although politicians in Ottawa supported the TMX pipeline, the Senate is currently progressing Bill C-69 through the legislature; this would see a complete overhaul of Canada's regulatory review process for natural resource projects. Opponents claim the regulations would mean no new pipelines would ever be proposed or approved in the future under the regulation. Given the lengthy delays already experienced in pipeline approvals and lower returns through crude price discounting, it is hardly surprising that new investment in Canadian production is at the lowest level in five years.

U.S. Counterparts

Ironically, while Canadian producers suffer and rein in their investment plans, their U.S. counterparts continue to expand output at record rates in the wake of the shale revolution. So while Canadian crude production increased by 55% or 1.5 mmb/d between 2010 and 2018, U.S. output doubled from 5.5. to 11 mmb/d over the same period. Although U.S. producers have seen some regulatory impact slowing pipeline build-out in the Midwest, the largest shale basin—the Permian in West Texas—has seen little obstruction to its growth. Easy access to the Gulf Coast and export markets has also helped address concerns about overproduction of light sweet shale crude.

Heavy Demand

Adding insult to injury for Canadian producers is the fact that the heavy sour crudes they produce are currently much in demand at the Gulf Coast and in Asia. That's because of a shortage of heavy crude resulting from OPEC and Russian production cuts as well as sanctions on Iran and Venezuela, which have tightened the heavy crude market. If Canadian producers could get their barrels to the Gulf Coast market reliably or export them to Asian markets from the Pacific Northwest Coast, they would have little trouble finding buyers today.

Longer term, however, the viability of Canadian heavy crude production faces headwinds. Aside from the environmental argument inside Canada over whether to exploit these carbon-rich resources, demand for heavy crude could subside next year as new International Maritime Organization regulations come into effect. These regulations require fuel oil used by ships to have an ultralow sulfur content of 0.5% come January 2020 compared with a 3.5% maximum today. One consequence of the regulations is that Asian refiners currently processing heavy crude and producing high-sulfur fuel oil typically sell that residue into the ship bunker market. These refiners don't have coker units at their refineries to turn the residual fuel into lighter, more valuable products. As a result, they may instead have to process lighter crudes, like U.S. shale, which have low sulfur content that can be blended into compliant bunker fuel. As we pointed out in a recent note on PBF Energy's bet on heavy crude refining (PBF Extends Heavy Crude Bet in California), a broader switch by refiners to lighter crude will weigh on heavy crude prices.

Unless Canada resolves takeaway constraints on its crude industry, we expect investment to continue declining, resulting in a further slowdown in production over the next decade.

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For More Information

+1 800 546-9646 North America
+44 20 3194 1455 Europe
commoditydata-sales@morningstar.com

MORNINGSTAR®

22 West Washington Street
Chicago, IL 60602 USA