Alberta Intervenes to Protect Producers

Short-term impact of Canadian crude cuts.

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Data Sources for This Publication
National Energy Board
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To discover more about the data sources used, click here.

Desperate Attempt to Protect

OPEC and NOPEC met in Vienna last week to decide a 1.2 million barrels/day production cut in the hopes of bolstering crude prices for 2019. A week earlier, Alberta—home to 76% of Canada's crude output—announced that it, too, would cut production by 325 thousand barrels/day, representing 8.7% of the province's average 3.5 mmb/d production between January and October 2018. The unheard-of cuts by the world's fourth-largest producer (behind the U.S., Russia, and Saudi Arabia) represent a desperate attempt to protect producers from discounted oil prices that saw local benchmark Western Canadian Select crumble to $16.58/barrel on Nov. 9, well below break-even levels. This note looks at the impact of the cuts on Alberta producers as well as the U.S. market they serve.

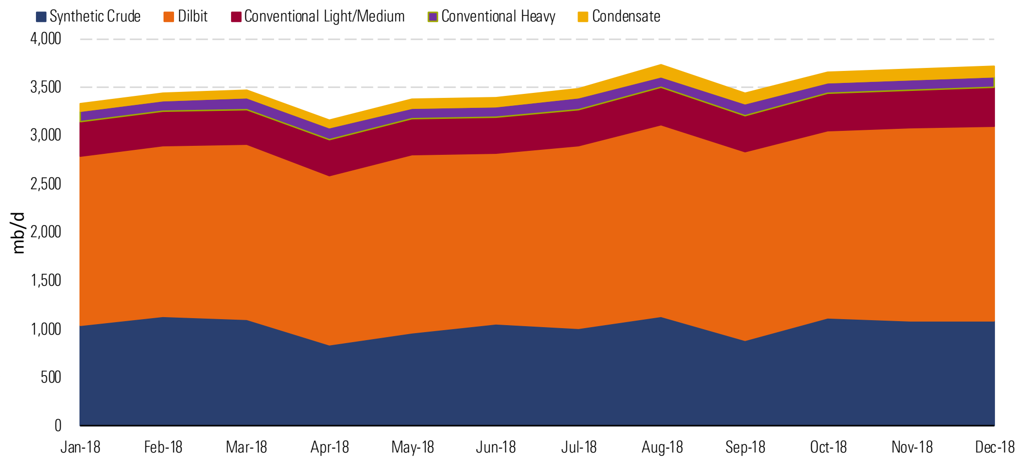
The Cuts

Announced on Dec. 2 by Alberta Premier Rachel Notley, the cuts will lower production of conventional and oil sands bitumen crude by 325 mb/d, or 8.7% from January 2019, until excess storage is drawn down—expected to take three months. The reduction will then drop to 95 mb/d until the end of 2019 at the latest or when additional rail transport capacity becomes available. The Alberta government previously announced plans to purchase rail tank cars to ship 120 mb/d of crude by rail but has to wait up to a year for the tank cars to be built and delivered. To protect smaller producers, the first 10 mb/d output is exempt from the cuts. Each company's share of the cuts will be based on its six highest months of output during the past 12 months starting with November 2017. That baseline value, less the 10 mb/d exemption, will be subject to an 8.7% cut. Alberta's Energy Minister indicated that 25 companies will have to make cuts. The immediate goal is to raise Canadian crude prices by at least $4/barrel.

Alberta Production

Canada's total crude output is forecast by the National Energy Board to average 4.6 mmb/d in 2018. About 93% of that total, or 4.3 mmb/d, comes from western Canada, with 81%, or 3.5 mmb/d, produced in Alberta. Two types of crude are recovered in Alberta—conventional and bitumen from oil sands. Conventional crude includes traditional vertical drilling that produces heavy, medium, and light grades as well as more recent horizontal drilling and hydraulic fracking that produces light crude and condensate. By far the largest part of Alberta crude (83%) is bitumen from oil sands that is either recovered by surface mining or extracted from below the surface by thermal processes such as steam-assisted gravity drainage, or SAGD. Most mined bitumen is upgraded to lighter synthetic grades that resemble light sweet crude, like U.S. benchmark West Texas Intermediate. Thermally produced bitumen is diluted with lighter hydrocarbons such as condensate or synthetic crude (known as diluent) to reduce its viscosity to flow in pipelines. Diluted bitumen grades, known as dilbit, are heavy and sour blends that need to be processed in complex refineries with coking capacity. Exhibit 1 shows the 2018 breakdown of Alberta crude production through October, according to the Alberta Energy Regulator.

Exhibit 1 Alberta Crude Production by Type



Source: Morningstar, Alberta Energy Regulator

Four upgraders operate in Alberta: Horizon (CNRL), Scotford (Shell), and Suncor and Mildred Lake (Syncrude). These produced just over 1 mmb/d during 2017, according to AER, with Shell and Suncor producing about 300 mb/d each and CNRL and Syncrude producing about 200 mb/d. As noted, most mined bitumen is upgraded, but the Imperial Kearl facility produces about 220 mb/d of dilbit crude from its mining operation.

Higher upfront investment costs for mining and upgrading mean that most new oil sands production is thermally produced dilbit, which is forecast by NEB to represent about 2 mmb/d of Alberta's 2018 production. Dilbit is typically blended with about 30% diluent produced as far away as the U.S. Gulf Coast and shipped to SAGD plants in Alberta by pipeline. According to AER, the largest SAGD producers in Alberta during 2017 were Cenovus (359 mb/d), Imperial (180 mb/d), Suncor (213 mb/d), ConocoPhillips (120 mb/d), CNRL (119 mb/d), Devon Energy (117 mb/d), MEG Energy (77 mb/d), Husky (62 mb/d), CNOOC/Nexen (41 mb/d), and Athabasca Leismer (30 mb/d). These SAGD producers as well as the upgraders will bear the brunt of Alberta's production cuts.

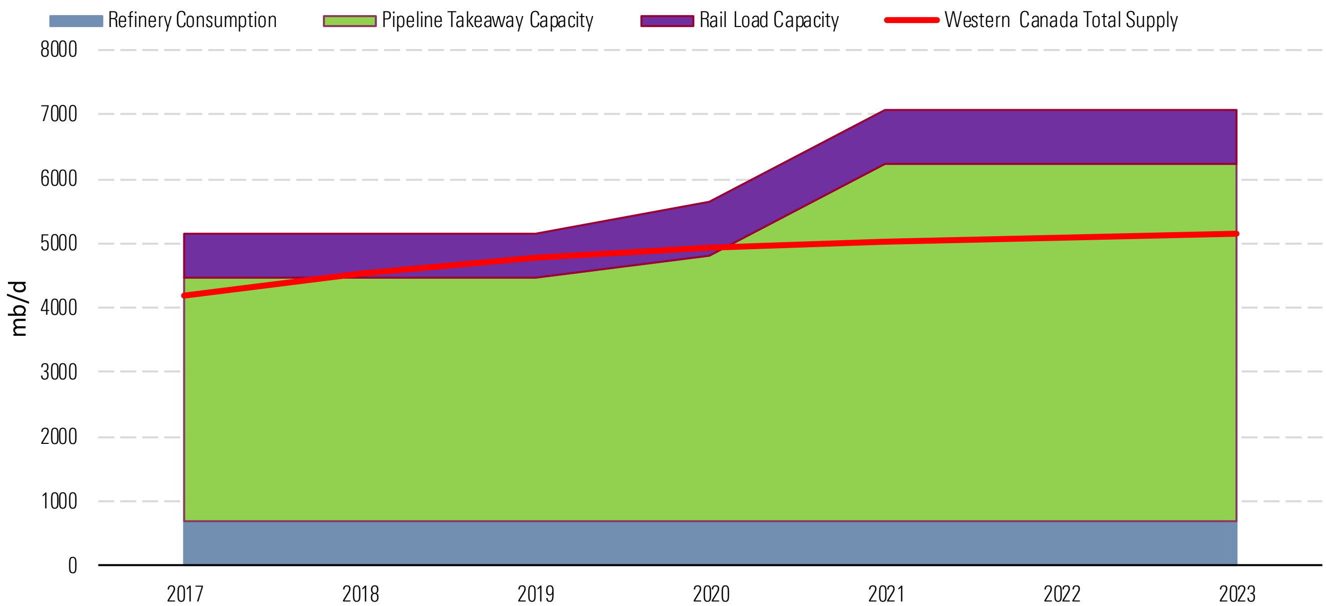
As detailed next, the need for production cuts is dictated by the lack of takeaway capacity to get Alberta's crude to market, most of which is exported to refiners in the U.S. Midwest and Gulf Coast.

Pipelines Full

The capacity issue for western Canadian producers arises because expanding crude production minus local refinery consumption is greater than existing pipeline takeaway capacity. Using rail transport to get around pipeline congestion is a potential workaround but is currently constrained by a lack of rail tank cars suited to transporting crude. In addition, although western Canada has about 700 mb/d of rail upload terminal capacity available, the railroads (CN and Canadian Pacific) are reluctant to sign up shippers without term commitment. Shippers in turn are reluctant to sign up over a long term because pipeline relief is on the way within a year. As a result, use of rail has been limited to a few larger players like Imperial and Cenovus that have rail terminal capacity and access to their own or leased rail tank cars. The Alberta government has committed to purchase 7,000 rail tank cars that will provide approximately 120 mb/d of transport out of Alberta, but not before the rail tank cars can be built and delivered, which may take until 2020.

New pipeline construction has been limited by lengthy permitting battles outside Alberta that have slowed the build-out of new capacity. Three pipeline expansions are currently awaiting final approval. The most advanced project 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 and is currently expected on line in late 2019. A second pipeline expansion is the Trans Mountain Express that was recently purchased from Kinder Morgan by the Canadian government to ensure the project is completed. That expansion, adding 590 mb/d capacity to the West Coast, is subject to a lengthy environmental impact analysis that will delay the capacity until 2020 at the earliest. Finally the TransCanada Keystone XL pipeline is a new pipeline between Hardisty, Alberta, and the Gulf Coast. The 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 but is now delayed by U.S. route and permit issues in Nebraska. If completed, Keystone XL would add 830 mb/d capacity and is currently expected on line sometime after 2020. These new pipelines will together alleviate crude takeaway congestion out of Alberta as early as 2020. Exhibit 2 shows western Canadian annual average estimated production (red line) and the refining, pipeline and rail capacity out to 2023. The current congestion is caused by production minus local refining exceeding pipeline capacity in 2018 and 2019 and part of 2020 depending on completion of expansions. During this period, shippers must rely on more expensive rail transport that is in turn constrained by the rail-car shortage.

Exhibit 2 Western Canadian Crude Takeaway Stack



Source: Morningstar, CAPP.

Price Discounts

Meantime, Canadian crude prices are being deeply discounted and storage inventory is building as excess supply builds up in Alberta. Prices for Western Canadian Select, the benchmark oil sands crude, have been discounted by as much as $47/barrel against U.S. benchmark West Texas Intermediate this year. WCS is normally subject to a discount against WTI of around $12-$15/barrel because the Canadian crude is of lower quality and because of the cost to ship Alberta crude to U.S. refiners. But when transport capacity gets tight, these discounts blow out to extreme levels as shippers compete for space on crowded pipelines. The level of discounts has been higher than usual this year—averaging $27/barrel between Jan. 1 and Dec. 4, 2018, compared with annual averages of $12/barrel in 2017 and $18.50/barrel during the previous five years. The impact became really painful in October and November when WTI prices fell by over 30% at the same time as WCS discounts widened to an average $41.24/barrel. That meant the absolute price Alberta producers received for WCS fell to an average $27.64/barrel in October and $18.19/barrel in November, with a record low of $16.58/barrel on Nov. 9. These prices are well below break-even levels, prompting action by Alberta's premier to cut production to prevent an oil industry recession.

Control Theory

The theory is that by mandating reduced production, the provincial government can reduce transport congestion for the benefit of all in a transparent manner. Alberta can implement production cuts fairly since it already closely monitors industry activity and output through the AER because the province extracts royalty payments. So far, the medicine is working, with WCS prices up /barrel $7.22/barrel between November 30 and December 6 since the cuts were announced last week. However, several considerations we detail below complicate this state market intervention policy:

- Some companies do better than others from production cuts. Producers with few downstream assets get all their revenue from oil prices and are most vulnerable to low crude prices that immediately affect their cash flow—CNRL, Devon Energy, and Syncrude, for example. Producers that have downstream refining assets are better protected against lower prices because they gain refinery margins from cheap crude as they lose revenue on crude sales - Suncor, Husky, Imperial, and, to a lesser extent, Cenovus, for example.
- The details available indicate cuts are purely volumetric, regardless of crude quality. If that's the case, then upgraders will lose more value because their crude is worth more. It is not clear whether dilbit producers will have to make cuts based on raw bitumen production or on the diluted dilbit that they ship to market. Arguably, the diluent is not "produced" but blended in afterwards. Expect producers with the option to cut more dilbit barrels.
- How will the mandated 325 mb/d cut respond to changes in production? The 12-month formula is based on previous production data. If the baseline volumes are recalculated each month then production will continue to increase unless the 325 mb/d isn't a hard ceiling.
- If the cuts are successful and reduce inventory, then will long-distance takeaway pipelines run partially empty as a result? If not, how will the regulator balance production and shipments?

These considerations complicate the process of state intervention in privately owned commercial oil markets.

U.S. Refiners

The cuts will also have mixed impacts for U.S. refiners. If crude imports from Canada are reduced by Alberta's cuts, then refiners in the Midwest will suffer higher feedstock prices and a scramble for alternative supplies. In the absence of Canadian heavy crude supplies, many Midwest refiners will be hard-put to source alternatives that would have to be imported from overseas. Gulf Coast refiners should be in better shape with easier access to alternatives on the world market. In general, we expect refiners to be worse off because their feedstock costs will increase, although arguably, they have enjoyed a lengthy boom on the back of discounted Canadian supplies that should see them through any current hardship (see our March 2017 Outlook "Heavy Bets Pay Off for Midwest Refiners").

U.S. Producers

With less competition from discounted Canadian supplies, U.S. producers should benefit from Alberta's cuts in two ways. First, higher prices should boost U.S. light shale crude producers because of reduced competition in the Midwest from Canadian synthetic grades. Second, any reduction in Canadian shipments to the U.S. that results from the cuts will benefit U.S. producers by freeing up space for them on long-distance pipelines. Both factors have already proved to be the case, with higher prices for light crude in the Midwest and reduced congestion in North Dakota for barrels seeking pipeline space on the Enbridge system.

Short-Term Boost at Best

The short-term impact of Alberta' crude production proposal has already met the province's goal of pushing crude prices higher and thereby protecting smaller industry producers. If the cuts are truly temporary and are tapered as Alberta inventories fall or rail capacity becomes available, then we expect the impact to be limited to market sentiment rather than supply/demand fundamentals. We do not expect less Canadian crude to be imported to the U.S. as a result. As such, the Alberta intervention works over the short term, notwithstanding harm to Midwest refiners. A greater concern arises if Alberta doesn't quickly remove the constraints when new pipelines come on line and becomes used to leaning on this crutch in support of higher prices longer term.

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