All aboard: A view of Alberta curtailment

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Canadian Oil Sands Dialogue | **Strategic Report**

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Key implications

Since the Government of Alberta announced that it would curtail output for 2019, the guidance and monthly curtailment volumes have evolved, and the timing of the Enbridge Line 3 Replacement project (previously expected in late 2019) was delayed by a year. This report provides a view on the key supply and demand developments in the western Canadian market and an assessment of their impact.

- **Since curtailment was announced, western Canadian crude price differentials have narrowed to a level much tighter than averaged in 2018.** Since curtailment was announced, the heavy oil differential between Western Canadian Select (WCS) at Hardisty and WTI at Cushing has averaged about $12/bbl. Mixed Sweet Blend (conventional light oil) has averaged less than $5/bbl beneath WTI, while Synthetic Crude Oil has averaged just over $1/bbl beneath WTI. This result compares with $27/bbl, $12/bbl, and $7/bbl beneath WTI in 2018, respectively.

- **IHS Markit expectations for Alberta production have increased over 2019 as Alberta has moderated curtailment and as publicly available information has increased.** We currently expect 2019 Alberta production to average 3.4 MMb/d, which is about 300,000 b/d less than our precurtailment outlook but certainly a more optimistic view of the potential level of Alberta output that would result in a much larger estimate of the scale of reduction. With a few exceptions, western Canadian supply available for export is generally exceeding pipeline takeaway capacity even with the completion of Enbridge Line 3 until additional pipeline can be brought online—the latter likely sometime in 2022.

- **The delay of Enbridge Line 3 increases the importance and the call on rail.** The estimated call on rail is highly sensitive to the productivity of oil production facilities and the state of provincial curtailment policy, which is currently less certain given the recent change in government in Alberta. Based on what we know today, owing to the delay of Line 3 to late 2020, the call on rail could crest over the winter of 2019/20 between 400,000 b/d and 500,000 b/d, which is typically the high point of western Canadian output.

- **Crude by rail remains critical for ensuring western Canadian crude market access and avoiding the extreme upstream price discounts of late 2018.** IHS Markit estimates that crude-by-rail capacity should exceed 500,000 b/d in late 2019—roughly capable of meeting anticipated demand. However, this estimate includes some rail capacity that was idled in early 2019 because of narrower price differentials. There is risk that should some of this capacity face delays in ramp-up, there may be little room in the market to absorb any takeaway upsets.

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About this report

Purpose. As supply overtook available pipeline takeaway capacity in 2018, western Canadian crude oil price differentials widened—a lot—and prices collapsed to record lows. As a result, the Government of Alberta made the extraordinary decision in late 2018 to impose mandatory production limits for Alberta crude oil production in 2019. This report provides a brief overview of curtailment, the impact on the western Canadian oil market, and the implications of the additional delay in the Enbridge Line 3 Replacement project.

Context. Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

Methodology. IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

Structure. This report has five sections.

1. How did western Canada get here?

2. Western Canadian 2019 production in curtailment

3. An evolving production outlook

4. Curtailment impact on prices

5. The question of adequacy of rail capacity

How did western Canada get here?

Price volatility was the defining story of the Western Canadian Sedimentary Basin in 2018. As pipelines that were proposed to increase western Canadian takeaway capacity were delayed, it became increasingly clear that oil supply would eventually overtake available pipeline export capacity and railroads would be required to move increasing volumes of western Canadian crude oil to market. However, what may not have been fully appreciated was that it would take time to bring online the required rail capacity, and thus capacity might lag demand. The result: extreme price volatility.

As new projects continued to ramp up over the course of 2018, pressure built on the western Canadian takeaway system. At times, some producers were unable to move crude to market. When differentials were at their widest, Western Canadian Select (WCS) at Hardisty—the principal western Canadian heavy oil benchmark—traded down as much as $50/bbl beneath WTI at Cushing. These extreme differentials, coupled with weakening global prices on the back half of 2018, caused the price of WCS in Alberta to reach lows of $14/bbl—worse than during the nadir of the global oil price collapse in early 2016. Although WCS was the most extreme example, all crude grades were impacted. Key light benchmarks such as Mixed Sweet Blend (MSW) and Synthetic Crude Oil (SCO), in Alberta traded $36/bbl and $33/bbl below WTI, respectively, at their widest, with absolute prices falling to nearly $20/bbl and $25/bbl, respectively, at their lowest.

Faced with a large reduction in the value of oil in western Canada, from which the province collects royalties, and the prospect that if the extreme differentials persisted, some smaller producers may have struggled to remain solvent, the Government of Alberta made the extraordinary decision to intervene in the market and limit production in 2019. On 2 December 2018, the government announced it would put in place mandatory production limits on individual operators in Alberta. Alberta is the largest oil-producing region in Canada; in December 2018, it was producing about 3.5 MMb/d—80% of western Canadian production.

The impact on western Canadian prices following the curtailment announcement was almost immediate. To be certain, differentials had already been narrowing as US Midwest refining turnarounds were subsiding and potentially being aided by voluntary production restraint within the market and anticipation that the government may intervene.[1, 2] However, there is no way to be certain how long it may have taken for differentials to mount a full recovery absent the curtailment mandate. The WCS-WTI differential dropped from a peak of $50/bbl in mid-October to $29/bbl just prior to the curtailment announcement on 2 December 2018. By the end of the trading day on 3 December, the differential narrowed to $22/bbl and two weeks later to $17/bbl. The differentials for lighter grades like MSW and SCO also narrowed from $23/bbl and $20/bbl, respectively, just prior to the announcement to $7/bbl and $3/bbl, respectively.

Western Canadian 2019 production in curtailment

Since curtailment was announced, the rules and curtailment volumes have evolved. In total, the Government of Alberta has made seven separate changes since 2 December 2018. Some were minor tweaks that appear aimed at increasing the equitability and/or flexibility for individual operators. Others were more material, such as how curtailment was being calculated and assessed for each operator, as well as changes in the amount of monthly curtailment.

Estimating curtailed production and allocation volumes is not straightforward, and, coupled with the ongoing changes and monthly allocations, there have been differences of opinion over the degree of curtailment and associated reductions. It has also become increasingly difficult to consistently forecast production since output is being dictated by the government with only one or two months' notice. Based on what has been announced to date, curtailment has reduced our expectation for western Canadian supply available for export in 2019 by more than 125,000 b/d, with the greatest impact felt by heavy, sour crudes.[3] However, the expected reduction from a precurtailment outlook depends on how curtailment unfolds (the degree of future curtailment) over the course of the year and on the level of production that could have been achieved in the absence of curtailment. A more optimistic view on the depth and breadth of downtime associated with seasonal oil sands maintenance; the expected utilization rate of key oil sands operations such as Syncrude, which showed nearly

1. Dan Healing, "Cenovus Makes Oilsands Cuts to Avoid Low Prices, 'Not for Charity,' Says CEO," Financial Post, 31 October 2018, https://business.financialpost.com/pmn/business-pmn/cenovus-reports-241-million-third-quarter-loss-lowers-capex-guidance, retrieved 24 April 2019; "Alberta Energy Firms Split on Call for Government-Imposed Production Cuts," CBC, 16 November 2018, https://www.cbc.ca/news/canada/calgary/production-oil-cuts-government-companies-husky-cenovus-suncor-price-differential-1.4909036, retrieved 24 April 2019.

2. US Midwest refinery turnarounds in the fall of 2018 were some of the deepest in the past three years. At its peak, nearly 1 MMb/d of capacity (and, as a result, demand) was offline.

3. Western Canadian supply available for export is western Canadian production, plus imported blending requirements, less regional refinery demand.

record levels of output prior to curtailment; or even the potential ramp-up of a new facility such as Cenovus's Christina Lake expansion could all result in a greater expectation of production in the absence of curtailment and thus a greater estimate of the degree of supply constraint. For more information on how to estimate curtailed production allocation volumes, see the box "How to estimate curtailment."

An evolving production outlook

Expectations for the 2019 Alberta production outlook have evolved along with changes to curtailment rules, progressive announcements of monthly allowances, and shifting expectations of the timing of the Enbridge Line 3 Replacement project. Currently, IHS Markit expects Alberta production to average 3.4 MMb/d in 2019, down from our precurtailment outlook of about 3.8 MMb/d.

Since curtailment was first announced, there have been three distinct changes to the rules, one of which had a material impact on the curtailment volumes for most operators. This rule change based the operator's curtailment off the maximum production month between November 2017 and October 2018, rather than the average of the top six months during that time frame. This rule change significantly increased allowable production for some operators that had projects in ramp-up during that time or had achieved above-average results in at least one month. The other two rule changes were aimed at more equitably distributing the curtailment between operators, particularly operators with projects in ramp-up.

Monthly curtailment volumes have also been modified over the year. At the onset of curtailment, the government had stated that monthly curtailment volume over first quarter 2019 would average 325,000 b/d and curtailment would step down to average 95,000 b/d for the remainder of the year. To date, the government has announced 325,000 b/d for January, 250,000 b/d for February and March, 225,000 b/d for April, 200,000 b/d for May, and 175,000 b/d for June. These changes have been a source of uncertainty for anticipated western Canadian output. Moreover, with monthly curtailment volumes announced for April to June in excess of 95,000 b/d, should the government wish to achieve its prior target of an average of 95,000 b/d from April to December, a lower level of curtailment will be required during July–December (for which the monthly curtailment volumes are yet to be announced). For the balances in this report, IHS Markit assumed a monthly curtailment volume of 95,000 b/d for the remainder of the year. The recent election of a new government in Alberta, which could change the direction of policy, is another source of complexity in the outlook.

Another source of shifting expectations has been over the timing of the Enbridge Line 3 Replacement project. The Line 3 Replacement project represents potentially the earliest new incremental pipeline capacity that could be brought online. The Line 3 Replacement project will replace an existing pipeline that runs from Hardisty, Alberta, to Superior, Wisconsin, which has been running at reduced capacity. This project will restore capacity to 760,000 b/d and result in an incremental takeaway uplift for western Canadian producers of about 370,000 b/d.

For many, the timing of Enbridge Line 3 was a potential pivot point in curtailment, with the additional capacity greatly increasing western Canadian takeaway. Early in the IHS Markit outlook, we had anticipated a need to remove or significantly weaken curtailment with the onset of Enbridge Line 3 operations. As recently as late 2018, Enbridge had indicated that Line 3 was expected online in late 2019; however, in early 2019 it was announced that the in-service date was delayed until second half 2020.[4]

As a result of the delay of Line 3, the likelihood that curtailment would remain in place to the end of 2019 increased. Production growth in 2020 may also be affected as upstream operators could decide to slow the

4. Please see "State of Minnesota Provides Permitting Timeline for Line 3 Replacement Project," Enbridge, 1 March 2019, https://www.enbridge.com/media-center/news/details?id=123564&lang=en, retrieved 12 March 2019.

How to estimate curtailment

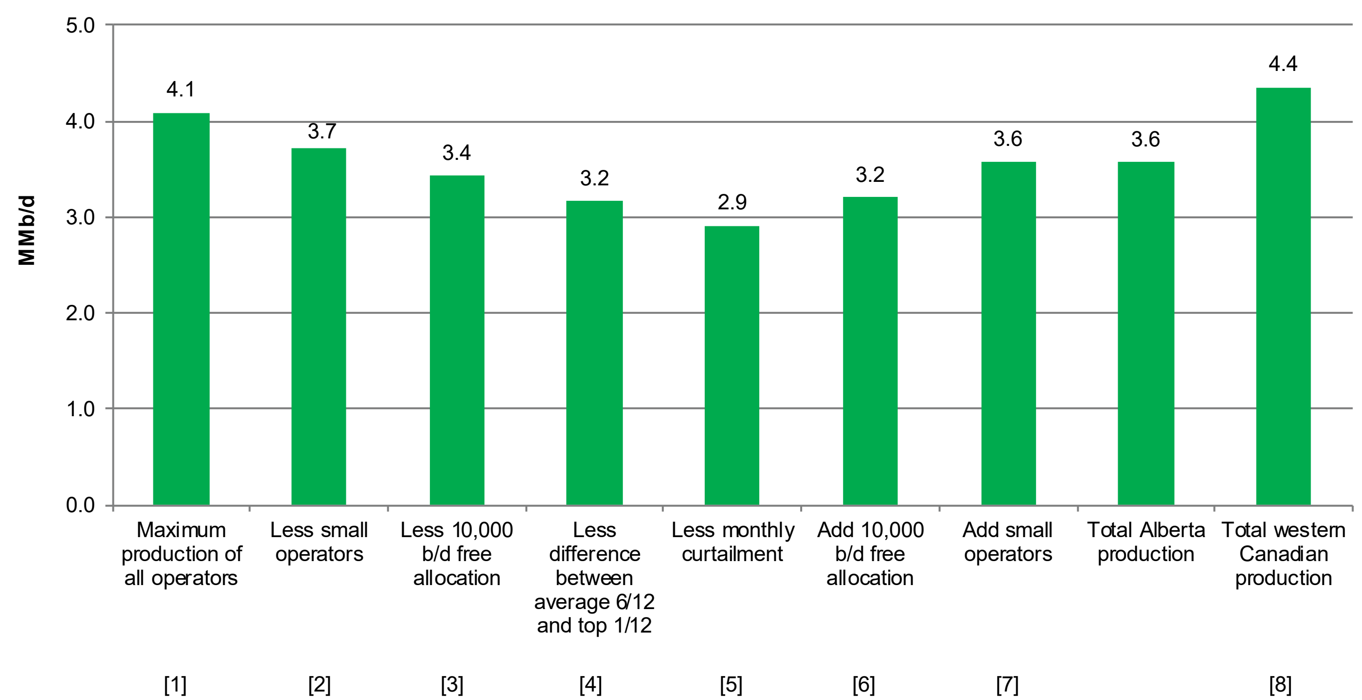
Estimating curtailed production allocation volumes is not straightforward. There are numerous steps in the calculation, and the order of these steps can impact the results. On 8 February 2019, the Government of Alberta released a presentation that better clarified the curtailment method as well as production volumes for each of the calculations.* This box outlines how curtailment is calculated using February 2019 average production and curtailment volumes as an example.

The first part of the calculation involves establishing the baseline, or maximum production of all operators, as denoted in Figure 1 by "[1]." The baseline is not the current, past, or forecast production but rather a calculation based on historical production for each operator producing light, heavy, and bitumen crude oil (pentane plus [including condensate], NGL, and natural gas production are exempt). The peak month for each operator from November 2017 to October 2018 is summed to attain the baseline. IHS Markit estimates the baseline to be 4.1 MMb/d.

From this baseline, the small operators that produce less than 10,000 b/d are removed, bringing the volume down to 3.7 MMb/d, as denoted by "[2]" in Figure 1. The volume is then further reduced by the 10,000 b/d that is free for operators that produce more than 10,000 b/d (large operators). IHS Markit estimates that 28 operators in Alberta produce more than 10,000 b/d. This result brings the volume down to 3.4 MMb/d (note [3] in Figure 1) and is referred to by the Government of Alberta as the adjusted baseline.

Figure 1

Government of Alberta production allocation calculation for February 2019



Source: IHS Markit

*Government of Alberta: "Curtailment Rules Under Responsible Energy Development Act," https://www.energy.alberta.ca/AU/History/Documents/CurtailmentRulesUnderREDAWebinar.pdf, retrieved 8 February 2019.

How to estimate curtailment (continued)

The adjusted baseline is further reduced by a difference established between the six-month average calculation and the top month calculation. IHS Markit believes this adjustment is the result of attempting to adjust for the difference in aggregate output that would result between the two calculation methods.** IHS Markit assumes the six-month average calculation to be the average of the top six months from November 2017 to October 2018 for total Alberta crude oil (excluding condensates). The top month calculation is attained similarly; however, it is only the peak month during this time frame. This reduction brings the adjusted baseline down to 3.2 MMb/d, as denoted by "[4]" in Figure 1.

Lastly, the adjusted baseline is further reduced by the announced curtailment volume for the month. For first quarter 2019, the announced curtailment volumes equaled 325,000 b/d for January and 250,000 b/d for February and March. This amount results in what the government is calling the combined provincial production allocation, which IHS Markit estimates to be 2.9 MMb/d, noted by "[5]" in Figure 1.

The production allocation for each large operator is calculated by dividing the combined provincial production allocation by the adjusted baseline, estimated to be 85% for February and March 2019. This result indicates that large operators are allowed to produce up to 85% of their peak month's production plus the 10,000 b/d free.

Total Alberta production can be reached by adding back the 10,000 b/d free for the large operators and the production of the small operators to the 2.9 MMb/d combined provincial production allocation, denoted in "[6]" and "[7]" in Figure 1. IHS Markit estimates total Alberta production in first quarter 2019 to be 3.6 MMb/d.

To understand western Canadian supply and demand (adequacy of takeaway), total Alberta crude oil production must be added to condensate supply from Alberta, as well as British Columbia, Saskatchewan, and Manitoba crude oil production, as noted in "[8]" in Figure 1, since all western Canadian crude competes for the same pipeline space. IHS Markit estimates total western Canadian production to be 4.4 MMb/d in first quarter 2019.

**This adjustment is noted by the box with red writing on slide 8 of the presentation by the Government of Alberta: "Curtailment Rules Under Responsible Energy Development Act," https://www.energy.alberta.ca/AU/History/Documents/CurtailmentRulesUnderREDAWebinar.pdf, retrieved 8 February 2019.

ramp-up of recently or soon-to-be completed projects to coincide with the revised timing of Line 3. Moreover, during the recent Alberta election campaign, the party that will now form the government indicated that the delay of Line 3 could impact the timing for the end of curtailment.[5]

Curtailment impact on prices

It can be argued that Alberta's production curtailment has been successful in reducing the extreme price discounts and volatility of 2018. However, curtailment remains a stopgap measure, and the underlying structural issue that led to it being invoked in the first place—the adequacy of takeaway capacity— remains. The recent delay of Line 3 underscores this point.

An unintended consequence of curtailment has been a narrowing of the price differential between western Canada and key export markets such as the US Gulf Coast to a level that has been insufficient to cover the higher cost of incremental rail transportation. IHS Markit estimates that when western Canadian heavy crude oil can clear the market by pipeline, the price difference between WCS at Hardisty and WTI at Cushing

5. Chris Varcoe, "Varcoe: Line 3 Delay Will Keep Oilpatch Spending Stagnant," Calgary Herald, 7 March 2019, http://calgaryherald.com/business/energy/varcoe-line-3-delay-will-keep-oilpatch-spending-stagnant, retrieved 22 April 2019.

should be $14–16/bbl (or slightly narrower in a tight heavy market, as has been the case recently), reflecting transportation costs and quality differences between the two crudes.

The most efficient form of rail transport—a dedicated train of roughly 100 crude tank cars known as a unit train—should result in a difference in price of $17–19/bbl (or potentially narrower depending on the type of crude, individual producer situation, and, in the case of heavy oil, a tight heavy oil market). Since early December 2018, the differential between WCS and WTI has averaged just $11/bbl—which is even better than what would be expected by pipeline economics.

To be fair, recently WTI has been afflicted with its own bottlenecks and constraints and has traded down from global benchmarks. An alternative comparison, with less noise, can be made between WCS at Hardisty and WCS in Houston, tracked by Argus Media. Over first quarter 2019, the WCS, Hardisty–WCS, Houston differential has averaged $13/bbl. This result is more than would be indicated by pipeline, which we estimate should cost $9–11/bbl between these markets, but less than what would typically be expected for rail, which we believe is in excess of $15/bbl.[6]

Nevertheless, as a result of the narrower differential, some producers opted to turn down their rail capacity early in the year that had been ramping up over 2018, creating concern over the adequacy of future rail capacity.[7]

Other producers indicated they have been able to break even moving crude oil by rail, and recently some operators that had turned down their rail capacity have announced the restart of the ramp-up of movements owing to improving transportation economics.[8]

The adequacy of rail capacity, which includes the time it can take to ramp up rail capacity, is a concern, since demand for crude-by-rail is anticipated to build over 2019 should curtailment ease and production rise into 2020 and beyond. Even with the completion of the Enbridge Line 3 Replacement project, this extra pipeline capacity is not expected to be sufficient on its own to absorb all of western Canada's potential production. In the interim, rail will remain critical to ensure that western Canadian output is able to get to market. IHS Markit believes this situation will persist until additional pipeline capacity can be brought online. Currently, Keystone XL and Trans Mountain Expansion are trending toward start dates in late 2021 and in 2022, respectively, although Keystone XL is increasingly looking like it may be delayed to 2022. However, should either of these projects be delayed further, the importance and call on rail will only increase. Irrespective of these pipelines, IHS Markit sees an extended use of rail as some operators have invested in significant rail capacity, which can be used to reach remote refineries unconnected by pipeline or take advantage of arbitrage opportunities that may emerge from time to time.

It is unlikely that the Government of Alberta intended for differentials to narrow quite as dramatically and affect the ramp-up of western crude-by-rail capacity. The government's stated aim was to reduce price volatility, narrow the differentials, and draw down storage.[9] We believe the government sought to narrow the differentials from levels in excess of $40/bbl while keeping them sufficiently wide to support crude-by-rail. To achieve this

6. It should be noted that rail companies have sought out longer-term contracts from oil producers to ship crude by rail. These contracts can result in both a fixed and variable cost in moving crude by rail. As a result of the fixed cost component, which the shipper must pay regardless if it moves oil or not by rail, the resulting price differential to cover or justify the movement of crude by rail is lower for existing capacity than would be required to justify new incremental capacity.

7. Please see Kyle Bakx, "Falling Oil-by-Rail Shipments Could Hurt Alberta's Plan to Clear Backlog," CBC, 7 February 2019, https://www.cbc.ca/news/business/ crude- by-rail-oilpatch-imc-suncor-cn-cp-1.5007949, retrieved 12 March 2019.

8. Please see Rod Nickel and Devika Krishna Kumar, "Cenovus Pressing Ahead with Aggressive Plans to Move Crude by Rail, Fearing Full Pipelines," The Globe and Mail, 21 February 2019, https://www.theglobeandmail.com/business/industry-news/energy-and-resources/article-cenovus-energy-pressing-ahead-with-aggressive-plans-to-move-crude-by//, retrieved 12 March 2019. Please see Nia Williams, "Canada's Imperial Oil Resumes Shipping Crude by Rail," Reuters, 26 March 2019, https://ca.reuters.com/article/businessNews/idCAKCN1R72R0-OCABS, retrieved 27 March 2019.

9. "Oil production limit," https://www.alberta.ca/protecting-value-resources.aspx, Government of Alberta, retrieved 24 April 2019.

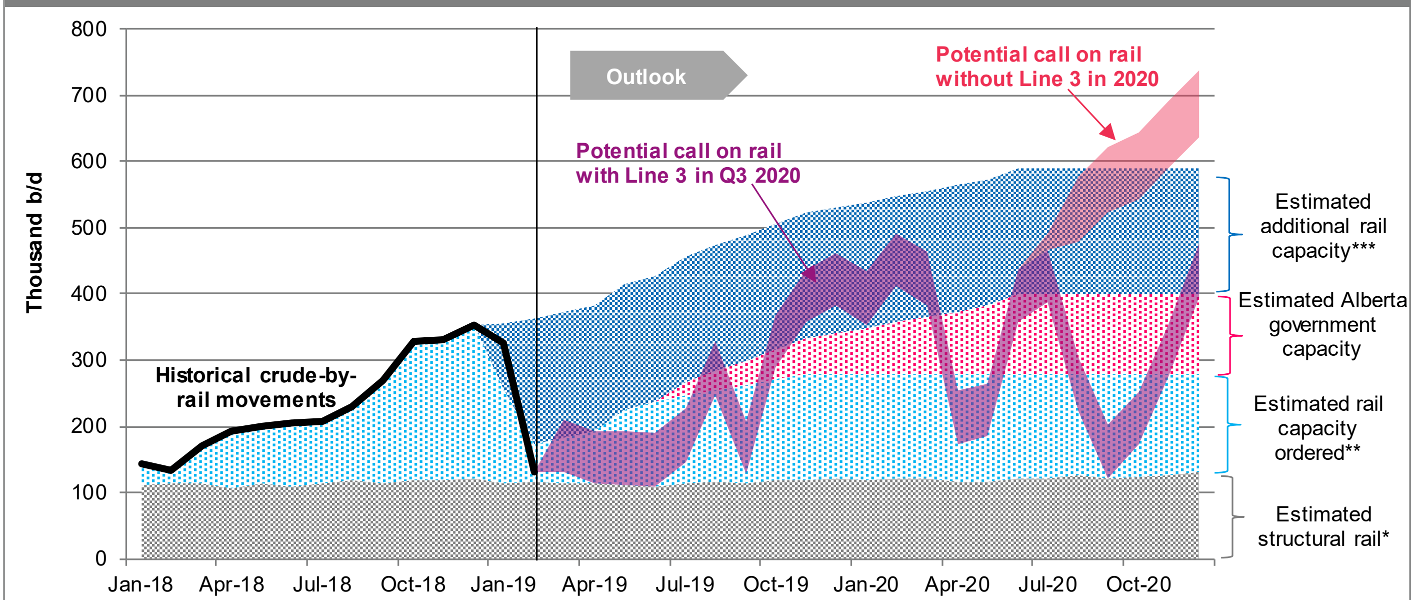
outcome, the government aimed to guide western Canadian export supply to a level that was above pipeline takeaway capacity but below available crude-by-rail capacity and thereby attempt to also draw down inventories. However, the data precision required to accurately achieve this balancing act on a 4.0 MMb/d system may simply not be achievable. Western Canadian production data typically lag two to three months, and the entire system is dynamic: production ebbs and flows, as do pipeline operations, which can impact throughput.

Moreover, the width or margin of error in placing western Canadian supply to achieve the Alberta government objectives is exceedingly narrow. At the time of curtailment, the estimated difference between total pipeline capacity and total estimated rail capacity was about 300,000–350,000 b/d. Moreover, we believe there is approximately 120,000 b/d of crude-by-rail that may be “structural,” meaning production volumes that are tied to long-term rail contracts predating the current situation and thus do not compete for pipeline capacity. As a result, the price-setting fairway between pipeline and crude-by-rail may be even narrower—potentially between 160,000 b/d and 230,000 b/d. On a system of about 4.0 MMb/d, this result amounts to a margin of error of 4–5%. Since curtailment was announced, Alberta has been gradually easing limitations, appearing to try to increase supply to push differentials out toward a price difference more supportive of the economics of western Canadian crude-by-rail exports.

Looking at Figure 2, which takes into account both structural rail and potential error, it appears that the call-on-rail may be reduced over the first half of 2019, and narrower differentials more closely associated with pipeline economics have the potential to prevail until turnarounds are complete this year (May/June). However, the duration and depth of oil sands turnarounds, western Canadian inventory levels, and the fact that Alberta is allowing trading of curtailment allowances between operations creates uncertainty in estimating supply available for export. Following the turnaround season, wider differentials more consistent with crude-by-rail should settle into place. Except for turnaround periods, we expect wider price differentials, consistent with crude-by-rail economics, to persist right up to and even after the streaming of Line 3, continuing until the next pipeline can be brought online (currently anticipated for 2022).

Figure 2

Western Canadian crude oil call on rail



Note: The call-on-rail outlook represents the physical requirement on a month-to-month basis of supply available for export in excess of pipeline takeaway capacity. *"Structural rail" is established crude-by-rail movements that predate the volatility in 2018, which IHS Markit estimates to be about 3% of total supply. **"Estimated rail capacity ordered" is based on February 2019 movements (last actual data available) and is adjusted for various producer announcements (up and down) (historical less crude-by-rail movements that are expected to be down in first quarter 2019). ***"Estimated additional rail capacity" includes the maximum of known prior and anticipated capacity (including historical peak movements by operator and not just recent announcements).
Source: IHS Markit

The question of adequacy of rail capacity

Crude-by-rail remains critical for ensuring western Canadian crude oil market access and avoiding the extreme upstream price discounts in late 2018. Several producers and the Government of Alberta have invested in incremental rail capacity, which will ramp up over 2019. Figure 2 presents the estimated call on rail based on our current understanding of curtailment, including it ending on 31 December 2019 as originally announced. As shown, the call-on-rail could crest between 400,000 b/d and 500,000 b/d through late 2019 and into early 2020, corresponding with the high point in the annual production calendar as winter drilling results begin to emerge, oil sands facilities aim to operate at their best, and diluent blending rates rise to offset colder temperatures. This result may exceed our current estimate of rail capacity believed to be in ramp-up, which includes rail capacity announcements made by companies ("estimated rail capacity ordered" in Figure 2) but not rail capacity that was reduced or turned down. If the preexisting, now reduced, rail capacity is fully revived (denoted as "estimated additional rail capacity" in Figure 2), the chance of another oversupply and resulting price instability will be substantially reduced.

It is important to acknowledge the uncertainty in IHS Markit estimates of both the anticipated call-on-rail and available rail capacity. The call-on-rail shown in Figure 2 represent the physical requirement on a month-to-month basis of supply available for export in excess of pipeline takeaway capacity. The volatility of the forecast call on rail is the result of seasonality—particularly turnarounds—anticipated curtailment levels, and the timing of Enbridge Line 3 in late 2020. In reality, month-to-month changes in movements will likely be smoother as operators choose to keep their railcars moving because of firm or fixed cost commitments of crude-by-rail, inventory changes, and arbitrage opportunities that may open up. Our estimate of available rail capacity is based on company announcements. We are aware there is additional rail capacity that we are unable to quantify that is held by some midstream and energy marketing firms. As a result, available capacity may be greater than is shown. That said, most of the anticipated rail capacity is not common carrier or publicly accessible and, as a result, access is not equitably distributed across the industry. Moreover, crude-by-rail capacity does not emerge overnight, requiring time to acquire or lease tank cars, arrange upstream and downstream loading and unloading agreements, and obtain transportation capacity from the railroads. Given the potential lead time to meet the anticipated call on rail, rail capacity would likely have to already be on order to meet future demand.

The key takeaway from Figure 2 is that the balance between anticipated export supply and takeaway capacity appears tight throughout the next year to year and a half. In the absence of sufficient spare capacity, the system may be particularly vulnerable to any disturbances such as pipeline upsets or extreme weather, which can affect rail capacity. Even with the completion of Enbridge Line 3, available supply is anticipated to exceed pipeline capacity, and the need for rail will remain until additional pipeline capacity can be brought online potentially in late 2021 or in 2022. Should Line 3 be delayed further, more rail capacity, in addition to what is believed to be on order, would be necessary to support the anticipated supply outlook. Longer term, even if all pipeline projects advance as anticipated—which is a source of uncertainty in our outlook—we see a longer-term role of crude-by-rail, which includes providing an important backstop for any unplanned pipeline outages, connecting producers to more remote refiners across North America, and accessing any potential arbitrage opportunities that may open up from time to time.

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