Discounted Oil: Canadian Oil Spreads and the Expected Economic Impacts

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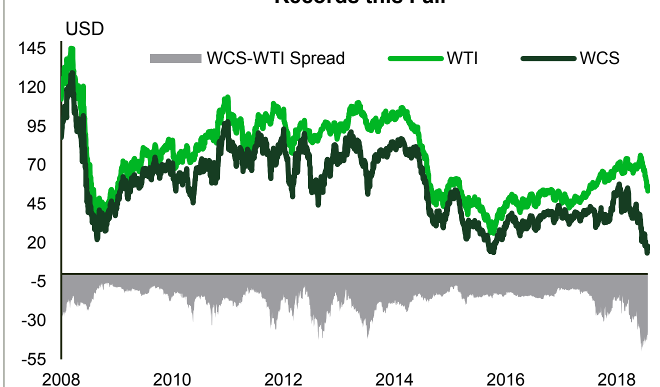
Highlights

- A recent swelling of price discounts for Canadian crudes during a time of softening global benchmark prices has been fueling worries about Canada's growth picture.
- This pressure has reflected a combination of structural factors, including rising production outpacing pipeline capacity, and temporary factors, notably higher than average planned refinery maintenance in the U.S.
- While much of the focus has been on the massive heavy oil discounts of US$40-50 per barrel, discounts on lighter and upgraded Canadian crudes such as Edmonton Mixed Sweet and Synthetic Crude have also surged.
- Price discounts of this extreme magnitude have not historically been sustained for more than a few months. Indeed, we expect a steady narrowing in the heavy oil spread to US$20-25 over the next few quarters. Light and upgraded oil spreads are also expected to narrow in lockstep.
- Provided that prices begin to normalize, growth impacts on Canada should be contained. Output cuts to date will shave up to 0.5 ppts from Q4 real GDP, with that activity recouped as 2019 progresses, resulting in only a muted impact on annual growth. Impacts will be slightly more pronounced in Alberta, with Saskatchewan also modestly affected.
- If current pricing holds, impacts on real activity, incomes, and government revenues would quickly mount. In that instance, Alberta's economy would be hard-hit and national Canadian growth could be cut by as much as 0.5 ppts relative to our current baseline path.

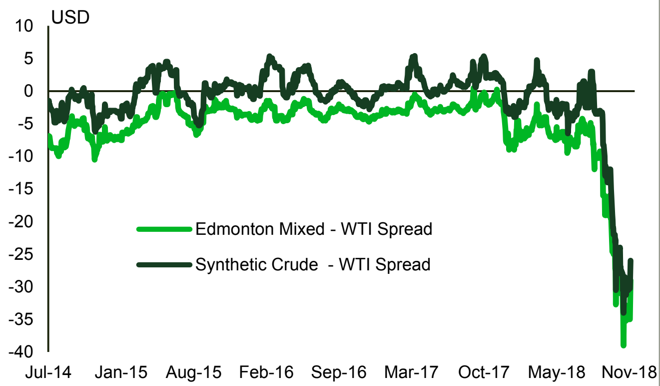
Canadian oil prices are taking center stage again. Amplified by longstanding transportation bottleneck issues and transitory refinery outages in the U.S., the spread between the Canadian heavy oil benchmark price (Western Canadian Select, or WCS) and the standard U.S. benchmark (West Texas Intermediate, or WTI) has hit record levels above US$50 this fall. With some recent softness in oil prices as a whole, the level of the WCS price benchmark itself also plunged to a record low below US$14 last week (Chart 1). The dramatic change in WCS pricing has generated a lot of attention, but the transportation issues have also created a discount on lighter and upgraded oil benchmarks in Western Canada, such as Edmonton Mixed Sweet and Synthetic Crude. These spreads have also been pressured to record levels, selling at discounts of more than US$30 below WTI despite their comparable quality profiles (Chart 2).

Chart 1: Canadian Heavy Oil Has Been Breaking Records this Fall



Source: Bloomberg, TD Economics

Chart 2: Lighter Oil Discounts also Surged



Source: Bloomberg, TD Economics

While oil discounts are not foreign to Western Canadian production, they previously occurred mostly during periods of rising global prices – and with the spread as a percentage of WTI prices usually significantly below its current levels, mostly leaving absolute prices at still-sustainable levels in relation to breakeven thresholds. The magnitude of the drop this autumn, and the generally persistent poor performance earlier this year have raised concerns about the sustainability of such levels, the oil and gas industry outlook, and the associated provincial and national economic impacts.

Heavy oil is increasingly a bigger part of the picture

As a number of large oil sands projects got underway in the pre-2014 high oil price environment, heavy oil production has been ramping ever since. Heavy production now accounts for approximately half of Canadian production – up from almost 40% in our 2013 report[1]. This trend is expected to continue given these projects' long life spans and high sunk costs, which generally prevent operators from significantly curtailing output regardless of the price environment. This approximately 50% heavy oil share consists of non-upgraded bitumen, at around 40% of total Canadian production, and to a lesser extent, several streams of conventional heavy oil, at 10% of production (note that data are 2018 estimates)[2]. Heavy Canadian oil is generally blended with diluent to allow it to flow through pipelines and is priced as WCS at the Hardisty, Alberta point of delivery to pipeline networks. It has historically traded at large discounts to the lighter WTI blend. These discounts reflect additional quality and refining costs due to its heavier density and sulphur content, as well as transportation costs, given its viscosity and the eventual shipment to refineries in the United States. The remaining half of Canada's production is divided between upgraded bitumen (23%), which is heavy oil that is upgraded and usually sold at the Synethetic Crude benchmark, condensates (9%), and conventional light oil (18%). The latter is mostly priced at the Edmonton Mixed Sweet and Brent benchmarks in Canada (See Table 1).

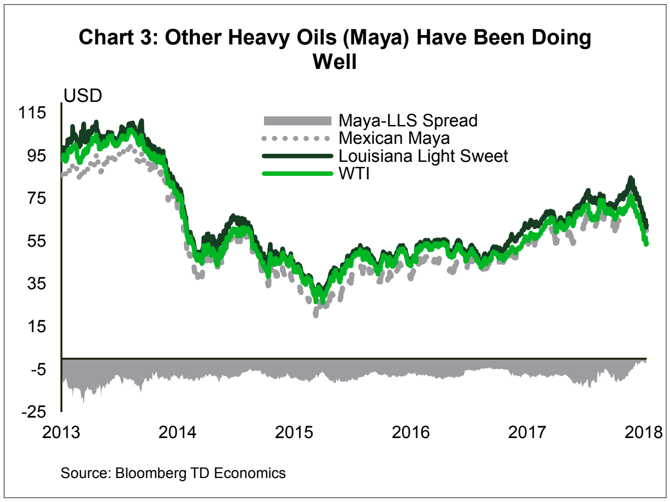
Provincially, Alberta and Saskatchewan account for most of Canada's oil production, at more than 90%, and are more exposed to heavy oil benchmarks. Alberta's production is skewed towards unconventional bitumen extraction and upgrading (Table 1). Conversely, Newfoundland & Labrador remains the only province currently sheltered from bottleneck-related discounts; with its offshore Brent oil prices trading at lofty levels - at least up until earlier in October and fetching a significant pre-

Table 1: Oil Production Shares

	% Share of National					% Share of Province			
	Canada	AB	SK	NL	Other	AB	SK	NL	Other
Total Light	**50**	**38**	**4**	**4**	**3**	**47**	**43**	**76**	**100**
Conventional Light	**18**	**8**	**4**	**4**	**1**	10	43	76	40
Upgraded Bitumen	**23**	**23**	**0**	**0**	**0**	29	0	0	0
Other (Condensate)	**9**	**7**	**0**	**0**	**2**	8	0	0	60
Total Heavy	**50**	**43**	**6**	**1**	**0**	**53**	**57**	**24**	**0**
Conventional Heavy	**10**	**2**	**6**	**1**	**0**	3	57	0	0
Non-conventional Heavy	**40**	**40**	**0**	**0**	**0**	50	0	0	0
Total	**100**	**81**	**10**	**6**	**3**	**100**	**100**	**100**	**100**

Note: Data are estimated the 2018 Yearly Production Averages based on a combination of actual and projected data. Totals may not add due to rounding.

Source: National Energy Board, TD Economics



mium over WTI (U.S. benchmark price discounts reflect transportation constraints south of the border – the pain may be worst in Canada, but it is not limited to there). However, Newfoundland and Labrador's share of total Canadian production is only around 6%. Conventional light oil production remains steady and offshore light oil production in Newfoundland & Labrador will eventually start to decline, implying that heavier oil will continue to represent a greater share of production and thus greater pressure on transportation and refining capacity.

Historical context: a volatile spread, but normalization always follows

Canadian heavy oil is fundamentally subject to a discount that accounts for quality differences and transportation costs[1]. Estimates would place the fundamental discount on WCS within a range of US$13-$17. This reflects a US$4-$10 premium[3] attributable to heavy oil pipeline transportation costs from Hardisty to Cushing, Oklahoma, or to Chicago[4], and a more varying quality discount usually estimated through the spread between the Louisiana Light Sweet (LLS) and Mexican Maya benchmarks[5]. Given the comparable quality of Maya oil and WCS, and the proximity of Mexican Maya to the Gulf coast, the historical LLS-Maya spread can serve as a proxy for quality. This has averaged US$8 in the last five years and has generally remained in the US$8-10 range. Interestingly, this spread has seen large declines this year, with the Maya benchmark itself actually trading above WTI levels recently (Chart 3). The 'standard' discount of US$13-17 can also be seen in the WCS-WTI spread's period of relative stability between late 2014 and 2017, where it averaged around US$14 and hovered mostly around the aforementioned range (Chart 1).

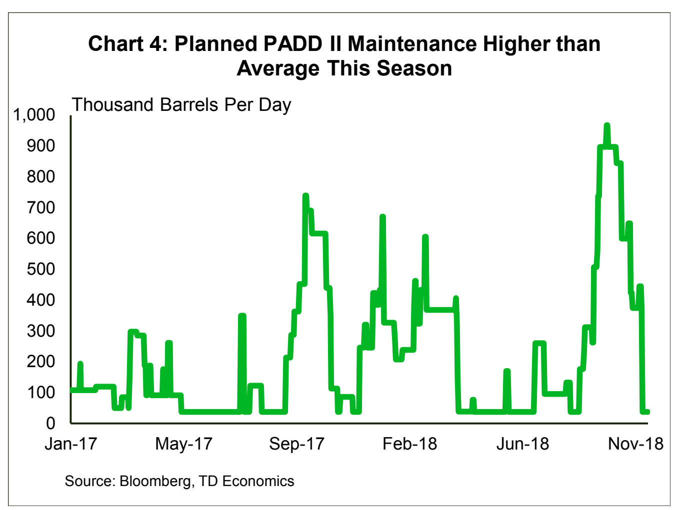
The lighter oil variations, on the other hand, have mostly traded closer to WTI – with Edmonton Light averaging a US$4 discount, likely reflective of transportation costs, and Synthetic crude trading at par or at a slight premium. The transportation costs premiums for these light grades that are not subject to quality costs are generally lower given the ease of flow relative to heavier grades, resulting in generally low spreads.

Elevated spreads are nothing new. For instance, in late 2012 and 2013, as oil sands production started to pick up in a high oil price environment, discounts ballooned to above US$30 as transportation bottlenecks started to materialize[6]. A transitory outage occurred in November 2017, where a leakage in the Keystone pipeline temporarily amplified pipeline bottlenecks and increased supply, sending the spreads to as much as US$30 temporarily. Historically, however, these periods of elevated spreads were always followed by a normalization to more sustainable levels in the historical average range. The question today though, is what level the spread will normalize to this time around.

What happened? Demand-side factors are largely transitory

The recent drop in prices has reflected both supply and demand factors. In turn, some of these factors are temporary in nature while others are more structural.

On the demand side, an important driver of the recent



record slump in prices – and the eventual spillover to lighter oil benchmarks, is likely to have been higher than average planned refinery outages during maintenance season in the PADD II (Midwest) region (Chart 4). These refineries are the largest foreign customer for Canadian heavy oil (Chart 5) – and may have thus contributed to an exacerbation of existing bottlenecks. The good news is that refinery operations are resuming to normal (see Chart 5), with the spreads also slowly following suit. The Whiting refinery in Indiana, for instance, one of the largest Canadian heavy oil importers, has already begun to restart processes.

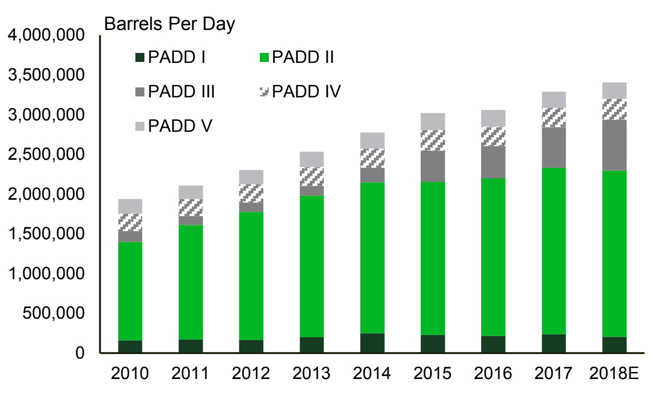
From a medium and longer term perspective, demand for Canadian heavy oil remains solid. Many refineries in the United States are configured and optimized to process heavier grades of oil, thus maintaining solid demand for the Canadian product. Canadian heavy oil competes with Venezuelan and Mexican heavy grades in the U.S. market, both of which have experienced declines in the last few years due to political instability and natural declines – and are likely to continue declining (Chart 6). The risk, however, remains, that in the face of Canadian pipeline constraints and the U.S. shale boom, some of these refineries may start retooling their configurations.

...But supply-side issues are the culprit and will remain

With these temporary factors fading, the more structural supply-side issue remains – that of rising oil sands production being unmatched by transportation capacity and diversified market access (Chart 7). This was particularly notable this year, as several oil sands projects, including the Fort Hills project, started ramping up production at a faster rate than expected. This exacerbated pipeline bottlenecks, contributing to a larger than normal spread for most of 2018. The two key pipelines expected to alleviate the structural pressures and diversify market access, TransMountain and Keystone XL, have experienced regulatory setbacks, delaying any potential construction until at least the next decade. Furthermore, a potential longer-term setback for the pricing of WCS is the implementation of International Maritime Organization shipping regulations on fuel quality in 2020, which are expected to impact high-sulphur oils, like Alberta's bitumen. Additional refining and upgrading capacity that are part of Alberta's Petrochemical Diversification Program will not come online until the next decade. It is not all bad news, fortunately. One positive development is Enbridge's Line 3 replacement project, which now having overcome all of its regulatory challenges, is expected to add upwards of 330K barrels per day of capacity by late 2019.

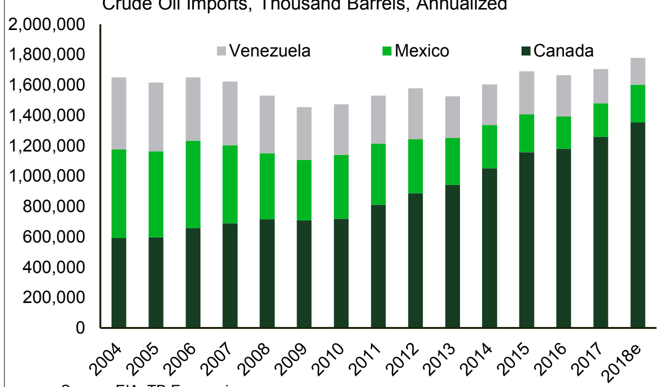
Meanwhile, producers have been resorting to less-than-ideal measures in response to this. Perhaps the most significant near-term support will come from producers' recently announced temporary production shut-ins, estimated to now surpass 160K barrels per day for both November and December, with the purpose of gradually balancing the existing glut. Coupled with a return to normal refinery utilization, the output curtailment should help to lower the currently elevated spreads. It is important to note, however, that output cuts are far from a first-best solution, as these projects' structures are optimized to continue ramping up production over the long term.

Chart 5: Almost all Canadian Oil Exports go to the U.S., with Most to PADD II (Midwest Region)

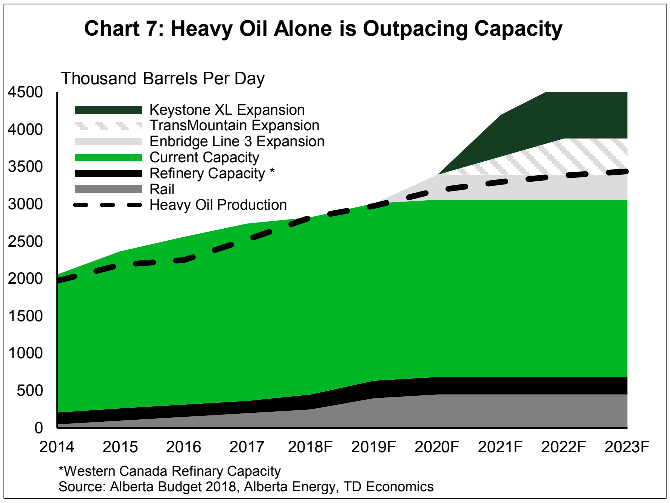


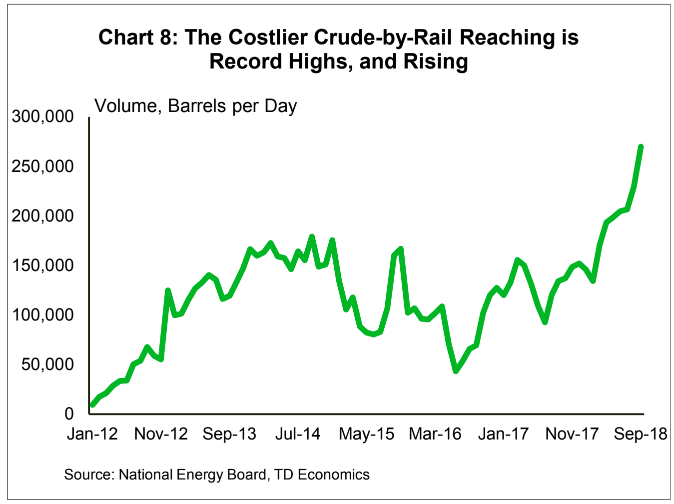
Source: National Energy Board, TD Economics

Chart 6: U.S. Importing More Heavy Oil from Canada, less from Mexico and Venezuela



Source: EIA, TD Economics





Meanwhile, many producers have been resorting to the more costly crude-by-rail option, sending shipments to record high levels of 270K barrels per day last September (Chart 8). Estimates, including those by the IEA, have forecast crude-by-rail shipments at 390K barrels per day in 2019. Indeed, a recently announced deal of 100K barrels per day by one of the largest oil patch companies is a sign that crude-by rail will likely surpass that mark in 2019. This was accompanied by further smaller deals from others, in addition to announcements by the two rail companies signaling an intention to increase shipments. Altogether, it appears likely that crude-by-rail shipments will likely surpass 400-450K barrels per day in 2019. The Alberta government has also proposed a plan that would fund additional rail capacity of up to 140K barrels per day, although the timing and likelihood of this happening are still uncertain. Additional capacity from the Sturgeon refinery in Alberta, while discouragingly delayed from Q2 to an expected Q4, should process around 80K barrels of diluted bitumen (and thus WCS). This should provide a modest outlet for some barrels in the near term.

Altogether, these short term supply-side solutions should contribute to an easing of bottlenecks, albeit only partially given expectations of a continual rise in production. Additionally, inventory buildups will probably take a few months to normalize. In short, this fall's slump, and the historical volatility of the spread, is a demonstration of an inland oil benchmark that will continue to be volatile and sensitive to any transitory setbacks given the transportation constraints.

Price outlook: a gradual, albeit partial normalization

We expect the differential to gradually normalize to the US$25-US$30 range during Q1 of 2019, and to the US$20-US$25 range during second half of year, as transitory factors fade and inventory buildups decline. With an assumption that WTI will also gradually hover towards the US$60-65 range by that time, this results in a WCS price estimate in the range of US$25-$30 in Q1 and US$30-$35 by the end of Q2. Of course, some downside risks exist to this outlook, based on global oil price dynamics, which may become more clear following the upcoming OPEC meeting in December.

The deviation of the spread from the historical US$13-$17 average is driven by the higher cost of rail transportation that will increasingly become utilized, additional storage costs where there is lack of pipeline capacity, in addition to the expectation that the market will still exhibit higher-than-usual tightness due to rising production. For instance, a previous study by CAPP placed estimated crude-by-rail costs between US$10-22 per barrel[7]. While illiquid and generally not a great indicator of where prices will materialize, the WCS futures strip nevertheless indicates a somewhat similar normalization pattern.

Meanwhile, lighter oils, notably Synthetic Crude and Edmonton Mixed Sweet, should see a speedier normalization pattern in 2019. These oils are generally easier to flow through pipelines than heavy oils, have lower transportation costs, and are less impacted by the eventual IMO regulations. Historically, WCS spreads have been far more volatile and are far more likely to surge than those of synthetic or light crudes, implying that its normalization path should be subject to more risk than the two lighter oil benchmarks.

Nationally, economic impacts are expected to be muted so far

A significant portion of the oil sands' real GDP impacts following the 2014 oil price shock centered on large hits to business investment. We expect that the already poor handoff will mean that any business investment cuts should not be be particularly noticeable from a longer-term GDP perspective, at least relative to the 2014-15 experience. This is especially given that investment in the unconventional oil sector hasn't recovered since 2014. Furthermore, the recently announced $2+ billion Aspen oil sands project in Northern Alberta, the first since 2013, should partially offset potential reductions in investment.

With this said, the production shut-ins recently announced will serve to impact the near-term growth profiles. Nationally, the impact of the approximately 160K+ barrels per day volume cuts on annual real gdp growth is expected to be somewhat muted, reflecting a reshuffling of growth through the quarters. Growth is estimated to be up to 0.5 ppts lower than would otherwise have been the case in Q4 and 0.1 ppts lower in the first quarter of 2019 due to production cuts. These are expected to be reversed as we approach the spring, boosting Q2 and Q3 gains modestly. It is a similar story for export prices (and thus Canada's terms of trade and income growth). These dynamics mean that annual growth is largely unchanged, as short term pain gives way to a recovery.

The effects will be slightly more concentrated and pronounced provincially

With the 160K+ barrels per day deduction representing a sizable portion of Alberta's monthly unconventional production, and with unconventional oil being an important part of Alberta's economy, we expect both volumes and confidence impacts to modestly subtract from our real GDP estimates. This leaves us with a combined impact of a 0.1 ppts cut to Alberta's real GDP growth in 2018, and up to a 0.2-0.3 ppts cut in 2019, with the higher range in 2019 driven by expected confidence, income, and consumer spending effects. Saskatchewan has a slightly lower hit in 2019 given its lower exposure to oil production as a share of real GDP. Of course, for the industry as a whole, the presence of integrated operations in some companies through partial or full ownership in refineries, in addition to the existence of partial financial hedges for others, mitigates a portion of the full price impact on corporate incomes. In other words, not all producers are fully subject to the currently elevated spreads and spot prices. Nevertheless, the unprecedented levels will serve to further dent confidence, potentially further reducing hiring and investment intentions.

Worryingly, even though Alberta's budget was relatively conservative with their WTI forecast, it estimated a WCS-WTI spread of US$22 for 2018-19 and US$21 for 2019-2020[8]. The government estimates that its revenues move by about CAD$210 million for a US$1 change in the spread. With the current discount levels, and with the average spread for the year now at more than US$27, this implies an approximately CAD$1 billion loss, all else equal. The actual impact is likely less than this, given the hedges mentioned above, the larger-than-expected increases in production (and thus increased royalties) from the Fort Hills project. Additionally, the first quarter update in August estimated the deficit at approximately CAD$1 billion less than the outlined deficit in the budget plan, owing to higher revenues from personal incomes and higher WTI prices earlier in the year– thus leaving the province with some buffer. Nevertheless, the risks of a higher deficit are skewed to the downside from the combination of elevated spreads and production shut-ins, especially going forward.

The Potential for sustained shut-ins will likely catch the BoC's attention (and ours)

Given the temporary nature of the refinery component of the shocks, we do not expect the Bank of Canada to react to these developments. Monetary policy is set for four to six quarters into the future, at which time more normal conditions are expected to prevail. We continue to expect the Bank of Canada to raise its monetary policy interest rate a further 75 basis points through 2019, starting in January. The expected move towards more 'normal' spreads should also help reduce downward pressures on the loonie, helping bring it towards the US79-80 cent mark.

The risk to this view is clearly skewed by current events. If by the time of the Bank's January interest rate decision, the dynamics remain unfavourable (i.e. further refinery delays, additional shut-ins, or a more permanent shock to spreads and/or prices), this would suggest a more prolonged period of weakness, and a worsening of the economic impact. Should this occur, we would expect the Bank of Canada to hold off on raising its policy interest rate until there is further stabilization in oil prices. The likelihood for any further hits to volumes through additional or further extended shut-ins will also likely have a more material impact on our national growth forecast. For instance, should prices hold at current levels, we would be likely to mark national growth down by as much as 0.5 ppts, and expect the Bank of Canada to do the same – a result that would be likely to preclude any further monetary tightening.

Bottom line

Historically, periods of rapidly-widening Canadian oil price spreads have not proved sustainable. And, indeed, we look for spreads to narrow in the coming months partly on the back of production cuts and a recovery in demand. The firming market conditions will in turn allow for some of the near-term output curtailment to be reversed as 2019 unfolds. Still, with transportation issues likely to remain largely unresolved over the medium term, we believe that the extent of price discounting on Canadian blends will remain wider than average.

This scenario would still result in some near-term pain for the economies of Alberta and Saskatchewan, but the hit to 2019 national real GDP growth due to the recent oil price collapse should prove relatively modest. Still, the path to a more normal price situation is not set in stone – far from it. Any setbacks prolonging the expected recovery would increasingly make an imprint on Canada's overall economy and slow the pace of monetary tightening. Moreover, until the structural transportation issues are addressed, there will remain significant concerns about the longer-term prospects Canada's oil sector and its ability to compete.

Endnotes

1. TD Economics, "Drilling Down on Crude Oil Price Differentials," 2013. https://www.td.com/document/PDF/economics/special/DrillingDownOnCrudeOilPriceDifferentials.pdf
2. Data is obtained from the National Energy Board. The calculations are a 2018 estimate based on a mix of actual and projected monthly, seasonally adjusted production by type and province.
3. Usually falls within the $5-$7 range when combined with other sources and if there is a long-term committed toll.
4. Canadian Association of Petroleum Producers, "2018 Crude Forecast, Markets and Transportation" 2018. https://www.capp.ca/publications-and-statistics/publications/320294
5. This proxy has been used before to estimate the quality spread, controlling for transportation. For example: Aliakbari, Almira, and Ashley Stedman "The Cost of Pipeline Constraints in Canada," 2018 https://www.fraserinstitute.org/sites/default/files/cost-of-pipeline-constraints-in-canada.pdf
6. Also referred to at the time as the "Bitumen Bubble"
7. Canadian Association of Petroleum Producers, "Transporting Crude by Rail in Canada," 2014. www.capp.ca/~/media/capp/customer-portal/documents/242427.pdf
8. Government of Alberta. "Budget 2018, A Recovery Built to Last," 2018. https://open.alberta.ca/dataset/8beb5614-43ff-4c01-8d3b-f1057c24c50b/resource/68283b86-c086-4b36-a159-600bcac3bc57/download/2018-21-fiscal-plan.pdf