BOE Report Weekly Round-up
February 28th, 2025

In a quiet week for upstream activity (though busy in the financial markets with a flurry of earnings reports), we watched E&Ps continue to execute their growth plans – drilling to fill processing facilities throughout the Montney and Duvernay.

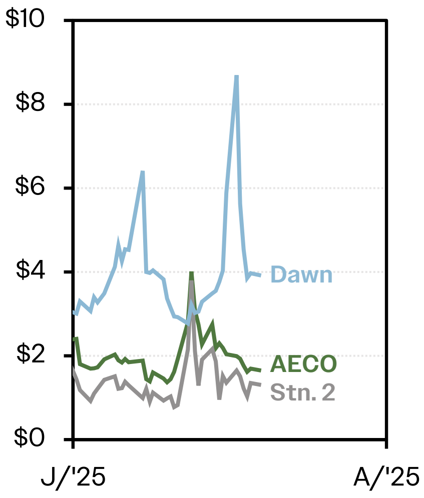
Kelt, unwavered by CSV noise, triumphantly continues to press on in the Montney, rig releasing a well on their 09-17 pad. Strathcona and Whitecap are both running rigs at Resthaven, hoping to push Kakwa south; with both companies having announced gas plant projects they intend to fill in the coming years (Strathcona an expansion of their existing facility, and Whitecap partnering with PGI for a new facility). Similarly, to fill their plant at Kaybob, Whitecap is running two rigs targeting the ultra-rich gas window of the Duvernay, which they'll complete after breakup.

Licensing activity was grim – with Veren permitting a massive pad at Gold Creek, and Spartan with another big pad this time in the Duvernay (on their 100% WI lands, opposed to inside their JV). Prairie Thunder applied for another Charlie Lake multilateral, IPCO for more Blackrod well pairs, and Strathcona for a new Meota pad – but nothing so radical as to unhinge our jaws (like, say, another batch of Cenovus Jean Marie multilaterals at Zama, which flowed at 135Bbls/d and 40Bbls/d of oil in January).

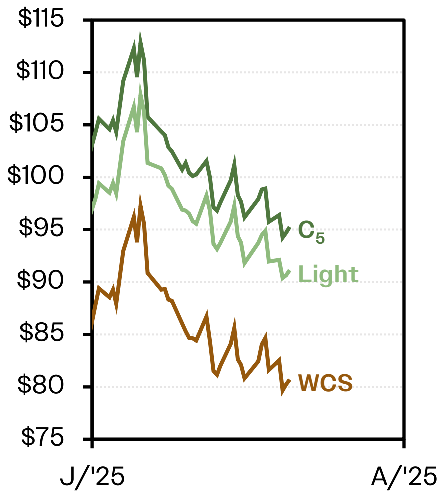
We watched NuVista flowback their Bilbo 10-29 pad, Logan flowback a well on their 11-22 pad – and a few other notable flares via the daily satellite passes (especially in the Hwy 671 area...)

All-in-all, while most wait for quarterly reports to gauge company performance, we monitor it daily through satellites, drones, and trail cameras – all integrated with well decline analysis, reserve estimates, subsurface modelling, regulator data, and price quotes – to provide an even better story than quarterly earnings can.

Producer Netback Gas Prices by Hub (CAD$/GJ)



Spot Edmonton/Hardisty Crude Pricing (CAD$/Bbl)



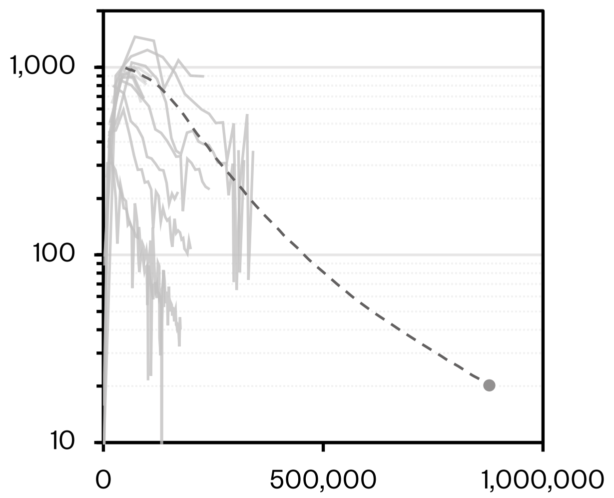
Note: Gas netbacks assume Gordondale plantgate, long-haul tolls assumed at minimum FT-R rates
Source: Bloomberg, NGI, HTM Data Suite

Weekly Headlines

- MEG releases 2024 financial results
- OBE releases 2024 financial results
- VRN releases 2024 financial results
- OVV releases 2024 financial results
- PPL releases 2024 financial results
- Pembina & Kineticor enter into a data center JV
- Trump revokes Chevron's Venezuela license
- Petronas expects first LNGC shipment in July 2025

HTM Energy Research

2-28.1: Teine Carrot Creek Results (BOE)

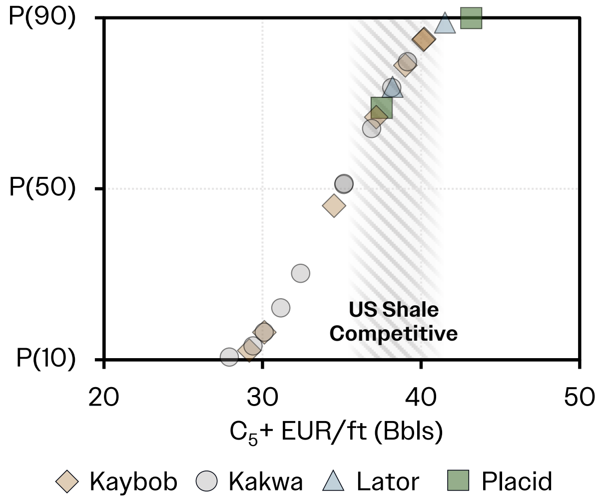


Privates Push Forward with Oil Exploration & Development

Well, there *was* some more exciting news out of Rainbow last week – when Spur put their single leg Haro Pekisko test well on production. Ensign's petite 650 single rig released this unstimulated lateral and it was quickly put on pump early last week. Spur is testing this play concept with a single-leg, trying to avoid the wet zones that previous Pekisko horizontals fracked into – we're extremely excited to see their early results.

Much further south, at Carrot Creek, Teine pushes forward with their Duvernay development, targeting an oil-rich part of the West Shale fairway with scant middle carbonate a good net thickness. Fascinatingly, for the midstream enthusiasts, we track Teine's gas through to the local Journey, Obsidian, and Vermilion plants, where the Duvernay gas is quite literally so rich, it alters the plant's throughput capacity. Even without the valuable ethane recovered (i.e. through a shallow cut), Teine's raw gas yields ~50Bbls/MMcf. At 13,500', we model raw oil EURs in the area at ~365,000Bbls, and total EURs in the ~800,000BOE range – notably, very competitive with their run-rate Viking economics (though, not with their recent 'success in the Success' at Dodsland).

2-28.2: Whitecap 2023+ EUR Probit Plot



Whitecap Kills it in the Montney & Duvernay After Buying XTO

There can't be a more steady company than Whitecap... After beating guidance and subsequently raising their production target multiple times in 2024 on the back of strong Montney and Duvernay results – Whitecap is back delineating land, while testing new well designs in the Montney. To the left we show HTMe EURs from their 2023-2024 capital program. Not shown on the chart to the left are their **monstrous** wells at Musreau Lake, where we estimate condy EURs >550MBbls. Whitecap has posted strong, consistent Montney liquids results while also maintaining gas upside without putting material value at risk for shareholders. One hint that Whitecap is consciously developing their Montney assets is how they drawdown wells compared to ARC; going for maximum EUR over IP.

Acquisitions have been a bad word over the last few years – but it's jarring to imagine where Whitecap (and even Veren) would be without them. Today, Whitecap has positioned themselves in two premiere plays, while deleveraging their balance sheet post-deal. Despite this, people still complain about deals, when it was deals that built the company! Since 2012, Whitecap has tripled production per share without using leverage irresponsibly.

Bonterra Makes a Mark in the Montney

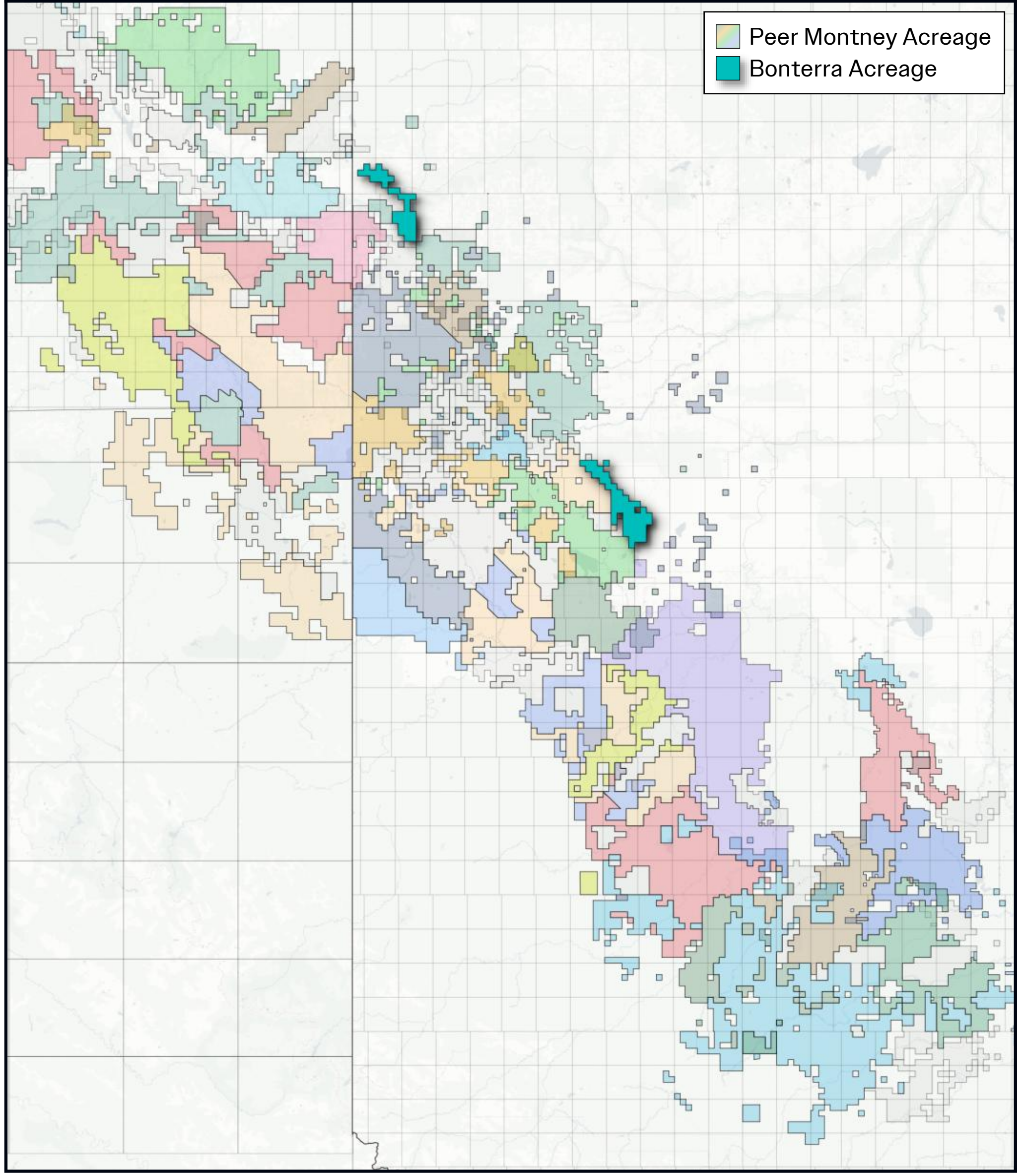
We just don't think that Canadian energy is 'hated' – though perhaps relatively ignored. A good example of the industry being avoided – is that fact that Bonterra has assembled, completely organically, a Montney play in the Wembley area, as well as a Charlie Lake play in the Bonanza area; both of which offer wholly superior capital efficiency and recycle ratio metrics to their legacy Pembina Cardium assets. And they did this without issuing any incremental equity, very impressive for a company of their cap size with limited access to capital, and beginning from a disadvantaged position with relatively high leverage out of COVID. A truly monumental feat the size of which can't be understated.

So far early-time results from the Montney asset they assembled have been very economic – our asset type curve at 3 miles of lateral length contemplates an ultimate recovery of 305MBbls of oil, 4.9Bcf of raw gas, and 105MBbls of NGLs, for ~1.1MMBOE on an unrisked basis.

While the IRRs may not rival the Cardium with their current cost structure, the F&D costs certainly do, at ~$8/BOE the Montney is the highest recycle ratio asset in Bonterra's portfolio, even at $2.50/GJ AECO. The shallower drilling depth allow for lower capital costs, and the strong liquids cut that doesn't decline as hard as the Cardium, makes for better lifetime economics than Pembina infills. The Montney, and their Charlie Lake asset (acquired from Archer in 2024), may not be meaningful to a larger SMID player, but for Bonterra, we think their shift into W6 has been a success story.

Now is a good time to interrupt this note, for the sake of our lawyer's sanity, to remind readers that nothing discussed within is investment advice. The discussion of various upstream assets, and the performance of said assets may have no bearing on the financial performance of related securities; please consult a registered financial advisor before making any financial decisions. HTM Energy Research ("HTM") is not a broker-dealer, and is not qualified to provide investment advice. Please carefully review the disclaimer attached to the end of this document. HTM partners, employees, and contributors have no interest of any kind in Bonterra Energy ("Bonterra") or related securities offered by Bonterra, and have no intentions to initiate one; HTM does not receive any fees for services, or compensation of any kind from Bonterra.

2-28.3: Greater South Montney Acreage Map

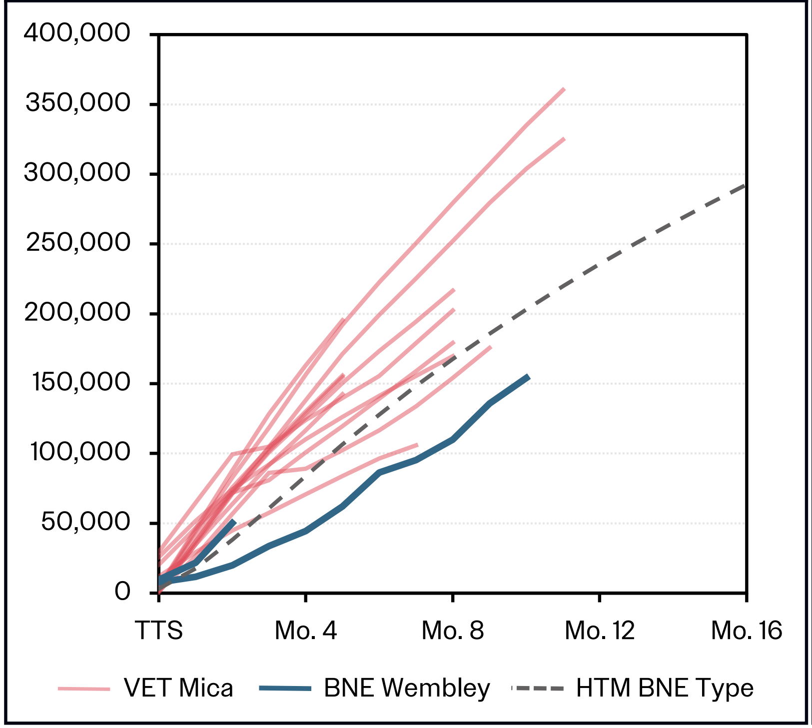


Bonterra's Montney Results Have Been immediately Competitive

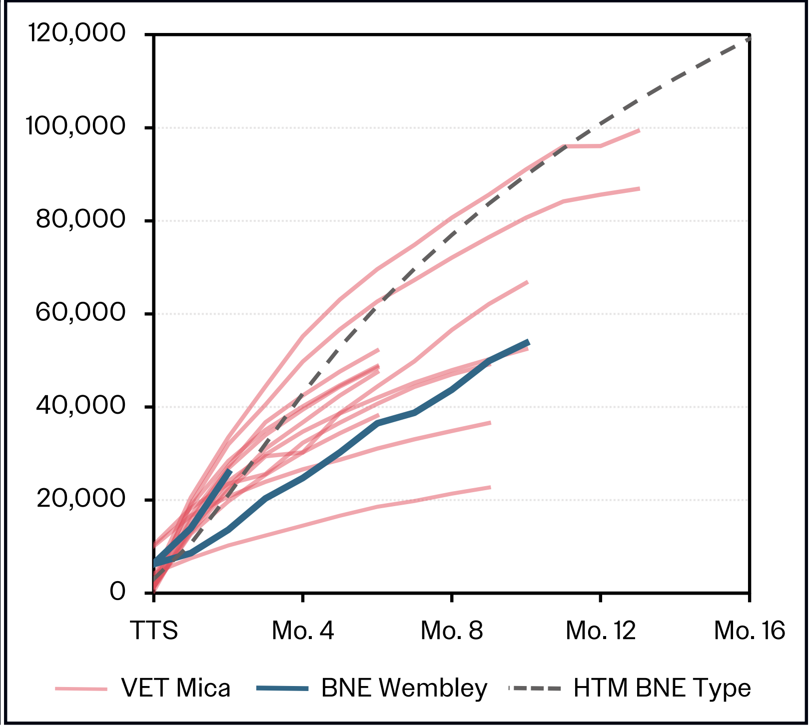
Field infrastructure buildouts and general downtime obscure calendar day rates from their initial drill, but Bonterra's 100/04-03 well is on pace to produce an adjusted oil IP_{365} of 180Bbls/d, with their recent TIL showing a peak IP_{30} rate of 400Bbls/d, and on a sales basis we estimate a ~900BOE/d IP_{30} – which is very strong for an initial trial, especially at a ~48% liquids weighting.

These results, in terms of oil production, are in-line with Vermilion's Mica asset (acquired from Leucrotta in 2022), though Vermilion handily wins in terms of gas and NGL volumes; with Bonterra winning on their full-cycle cost basis (recall, Vermilion is into their ~15,000BOE/d asset for ~$700MM – the $475MM deal, then facilities and DCE&T). Meanwhile, Bonterra will be slower to capitalize their Montney given limited liquidity. Notably, they plan zero Montney wells in 2025; but their focus on unconventional plays is already delivering massive capital efficiency improvements sequentially (their implied maintenance capital spending is down ~$15MM), drilling only 11 wells in 2025 to maintain production (compared to 20-30 in prior years, though that included a growth wedge). Fantastic.

2-28.4: Comparative Montney Cumes (BOE)



2-28.5: Comparative Montney Oil Cumes (Bbls)



We See >100 Locations

Using the reserves report we prepare for our own internal analysis, we see over 100 future drilling locations, accessible from <20 surface pads. Bonterra has begun some form of a surface infrastructure build on their flagship Montney pad, with a disposal well and battery now in place.

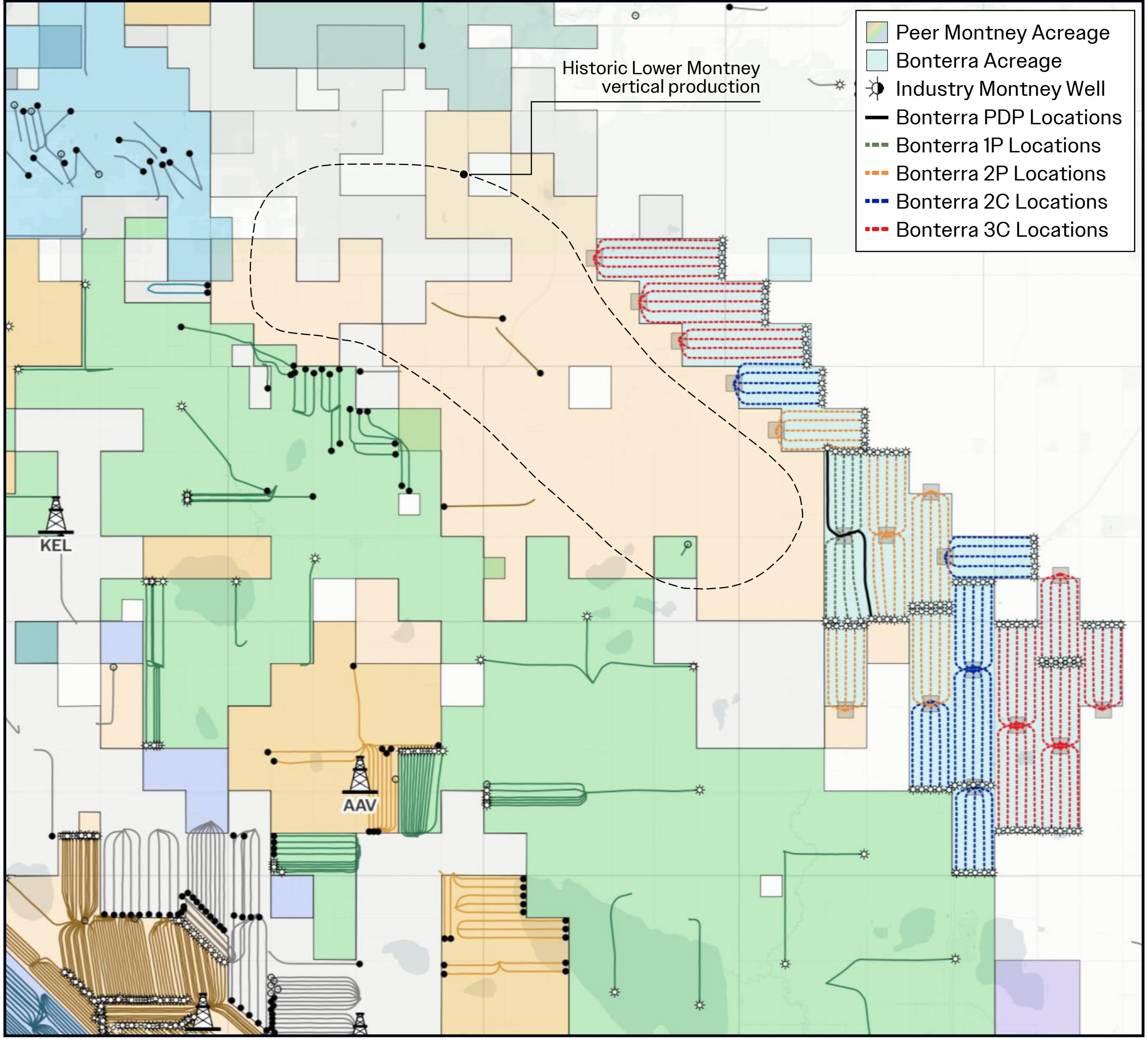
Notably, to the west of Bonterra's asset, the Lower Montney was targeted for gas production with vertical wells from the late 80s through to the early 2000s.

That same Lower Montney vertical gas production provides valuable insight into reservoir, a benefit that Bonterra enjoys both in terms of subsurface mapping – but they *also* have a prospective (but sour) Lower Montney bench across the western part of their asset; though their 2 Montney wells so far have focused on the Upper Middle interval, which has turned out to be less sour than expected.

With over 100 locations in just the Middle Montney, we see over 105MMBbls of total recoverable resource, and ignoring initial funding constraints, capable of growing to then maintaining plateau production at 10,000BOE/d for over 15 years. Truly an impressive feat for such a small company.

For general disclosure purposes, we should (and have to) say, that this analysis is not comprehensive, and not comparable, and should not be in any way compared to a reserve report generated by a qualified professional reserve auditor, of which HTM Energy Research, is not.

2-28.6: Greater Wembley Montney Acreage Map



Will Anyone Ever Return to the Alberta Bakken?

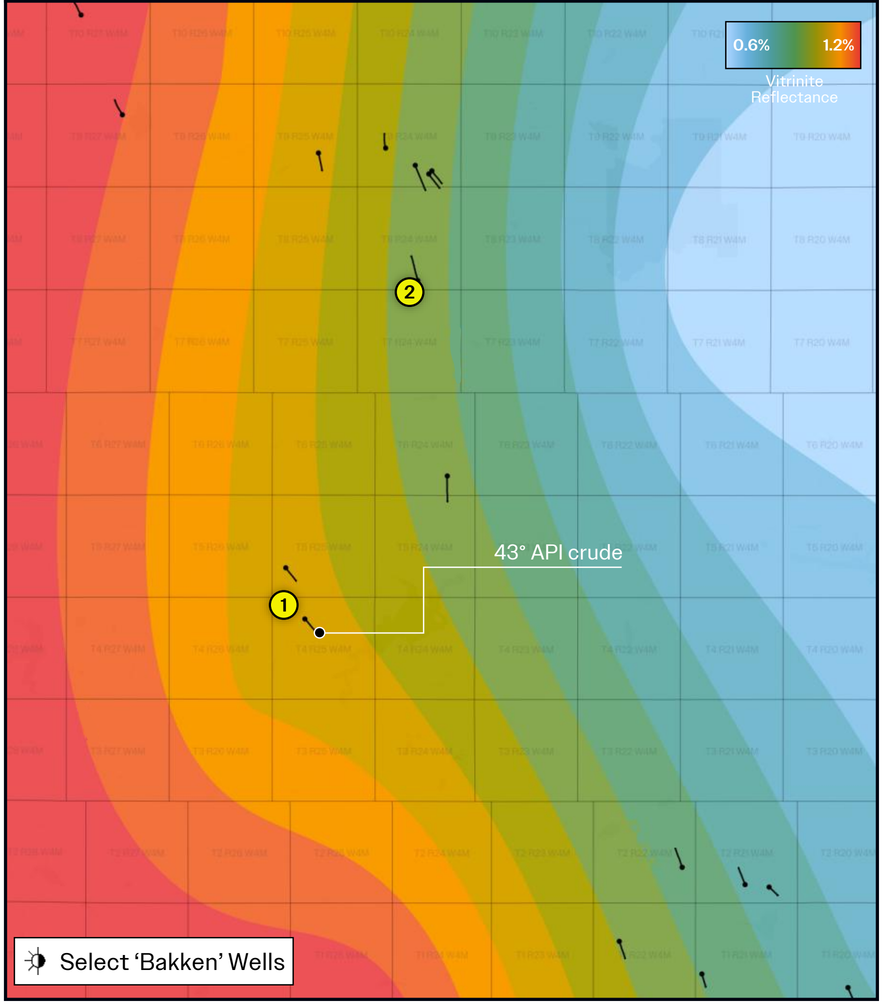
Many have tried, and many have failed – but what's one more? There's a real, and proven productive (though economic, TBD) petroleum system in Southern Alberta that has yet to be fully explored. Murphy, Shell, and a handful of other players attempted in the early 2010s, though with mixed success that didn't delineate the shale interval – and interpreting results is equally difficult. For example, the Murphy 100/09-29 well has a "Projected Formation" of 'Wabamun', but our analysis classifies it as an Exshaw well (the stratigraphic equivalent to the Middle Bakken); either way, it's a fantastic well, with an EUR of 450,000Bbls of light crude (115Bbls/ft). The Murphy well to the north wasn't as exciting, with a technical EUR of 125,000Bbls, though its since been suspended. There is also prospectivity in the Big Valley, which is equivalent to the Three Forks in North Dakota, and the Torquay in Saskatchewan.

Early "Alberta Bakken" exploration by companies like DeeThree (split into Granite Oil, and acquired by IPCO) targeted a Lower Banff migration play that some operators initially misclassified as the Exshaw. That's the Ferguson waterflood, and while it's in the whole "Alberta Bakken" unit, it's not the Middle Bakken equivalent member – which is stratigraphically equivalent to the Exshaw in Alberta. Tuktu has seen major success targeting this play further updip, with early test results from their Upper Banff sand recompletion flowing at ~400Bbls/d.

Early Exshaw wells targeted the shale group in the late oil generation window, as most early unconventional delineation wells did; while the consistent "sweet spot" for unconventional plays has been slightly past peak oil generation where the reservoir is also overpressured. This maps to a thermal maturity, as measured by vitrinite reflectance, of ~1.0%.

Though development wouldn't be without challenges – if operators thought sourcing freshwater in the Duvernay was tough, doing it in Southern Alberta would be near impossible. Though, there's a massive prize waiting in lurch for anyone that chooses to incinerate a few hundred million dollars chasing it! Institutional clients can login and access our recent Alberta Bakken exploration released early January.

2-28.7: South Alberta Bakken Maturity Contour Map



1. Early Murphy Middle Bakken test on the Blood Reserve, peak oil IP_{30} of 235Bbls/d, oil EUR of >450,000Bbls
2. Early Kainai Three Forks on the Blood Reserve, peak oil IP_{30} of 320Bbls/d, oil EUR of ~215,000Bbls

Montney Spacing Matters – Conoco Delivers a Masterclass at Inga

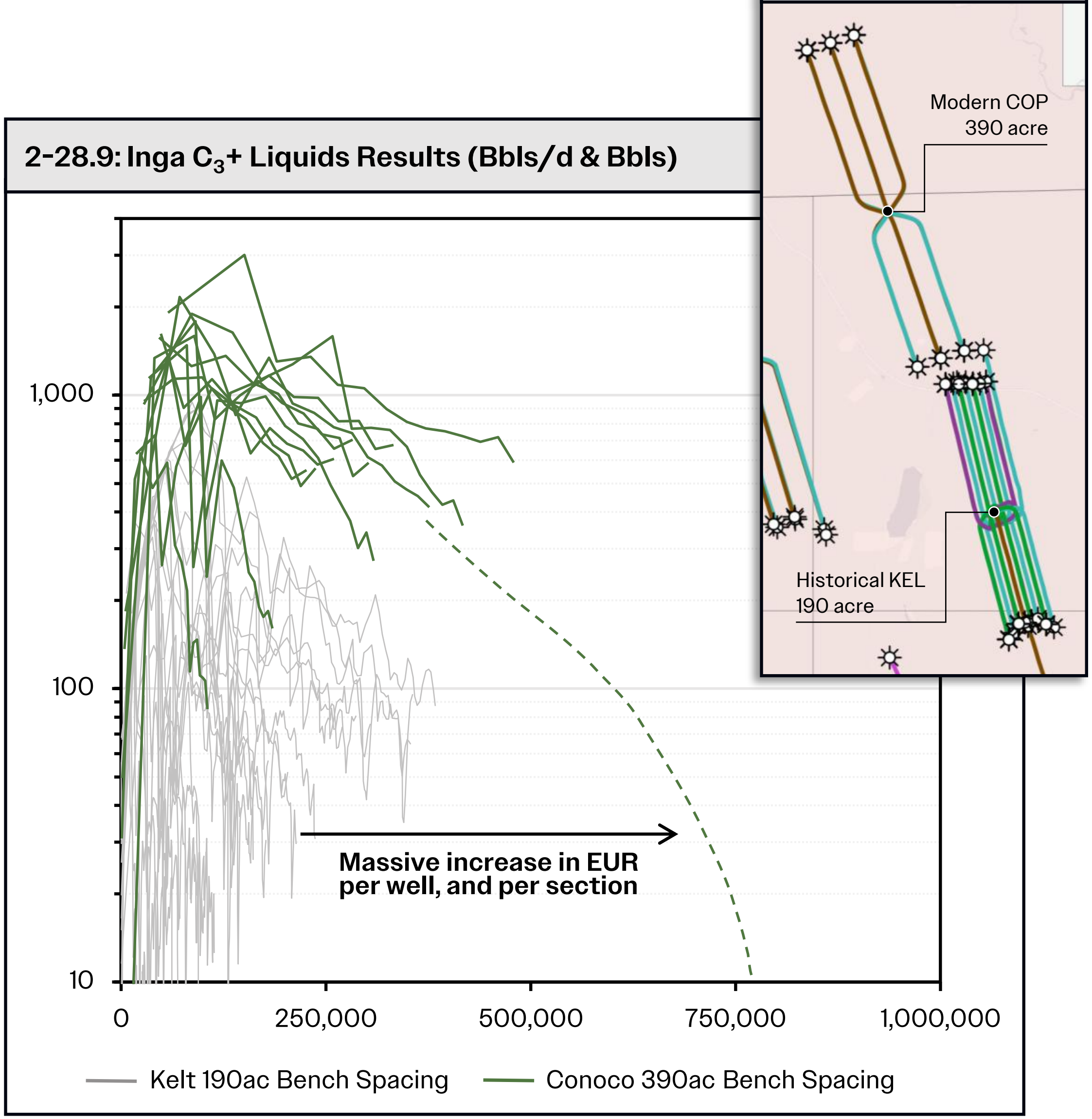
After acquiring the acreage from Kelt in 2020 for $405MM, ConocoPhillips substantially changed the asset's D&C design – widening spacing, and increasing proppant placed by over 200%. This change in D&C practice has resulted in some of the best wells ever drilled in the Montney, some paying out in less than 90 days.

Kelt's historical 190 acre bench-DSU wells codeveloped 3 benches at 18 wells per sections, and were spud throughout 2018-2019 – completed with ~4,000 tonnes of proppant. Lower wells were completed with 30-40 stages, and shallower wells completed with 40-60 stages. Liquids EURs range from ~100-435MBbls, including NGLs.

Meanwhile, ConocoPhillip's modern 390 acre bench-DSU wells codevelop 2 benches at 8 wells per section, with completions in the 11,000 tonnes range. Lower wells are completed with 30-40 stages, and the shallower wells completed with 60-80 stages. Notably, EUR per well and EUR per section have both increased. Single well liquids EURs range from ~300MBbls, to >1MMBbls, including NGLs.

It's not just at Inga – for example, at the Gordondale oil pool, historical development by Birchcliff highlights the dangers of overcapitalizing an updip liquids-rich Montney asset. In multiple instances, we've noted pads directly offsetting each other, ones with 9 wells per section, and ones with 3-4 wells per section – over their lifetime, both will produce the same amount of oil per section, reinforcing the importance of proper updip spacing when liquids is the primary target. Tighter spacing isn't necessarily always wrong, and many operators retain flexibility to downspace in a higher AECO environment (like, NuVista) with the ability to widen spacing and moderate completions with condensate prices.

2-28.9: Inga C_3+ Liquids Results (Bbls/d & Bbls)



2.28-8: Inga Montney Benching Inset Map

Disclaimers and Disclosures

Neither the information, nor any opinion expressed herein constitutes an offer, recommendation, inducement, or solicitation of an offer to transact in any securities, or other financial instrument(s). Opinions expressed herein are not investment recommendations, and are not meant to be relied upon as investment advice in any manner. HTM Energy ("HTM") is not an investment broker-dealer, or a registered investment advisor and does not provide professional financial investment advice. This document does not constitute an offer to sell, or a solicitation of an offer to purchase securities of any kind. The author(s) of this information may not be licensed to conduct regulated activities in your jurisdiction, and, if not licensed, do not represent themselves as being able to do so. Recipients who are not institutional investors or market professionals should seek the advice of their independent financial advisor before considering information in this document in connection with any investment decisions, or for a necessary explanation of its contents.

All information, including ideas, data, charts, models, opinions, and analysis of any kind in this document, is provided "as is", with no guarantee of completeness or accuracy, and without warranty of any kind, express or implied, including, but not limited to warranties of performance, merchantability, or fitness for a particular purpose. HTM assumes no responsibility for errors, omissions, inaccuracies, or misinformation in the contents of this publication. This publication, and all opinions, projections, and estimates therein constitute the judgement of the author(s) at the date of publication, and are subject to change without notice. HTM is under no obligation to update this information. You should therefore assume that HTM will not update any fact, circumstance, or opinion contained herein. Furthermore, HTM reserves the right to make additions, deletions, or modifications to any publication, chart, or model at any time, without notice, advance or otherwise. This document does not contain all the information that may be required to evaluate the matters discussed, and thus should not be relied upon.

HTM will not be liable to anyone for any decision made or any action taken in reliance on the information produced by this publication or for any consequential, special, or similar damages, even if advised of the possibility of such damages. In no event shall HTM be liable for any special, direct, indirect, or consequential, or incidental damages, or any damages whatsoever, whether in an action of contract, negligence, or other tort arising out of or in connection with the use of any HTM publication, chart, model, data, analysis, idea, opinion, or content of any kind. This information is prepared for the use of HTM clients and may not be redistributed, retransmitted, or disclosed, in whole or in part, or in any form or manner, without the express written consent of HTM. All information is distributed through HTM owned websites, or other licensed portals and affiliates.

This information has been prepared independently of any issuer of securities mentioned herein and not in connection with any proposed offering of securities or as agent of any issuer of any securities. Materials prepared by HTM personnel are based on public information. Facts and views presented in this material have not been reviewed by, and may not reflect information know to other energy professionals. None of the information contained herein has been filed, or will be filed with any regulating authority. No governmental authority has passed, or will pass on the merits of this document. The information obtained in this document was obtained from sources deemed to be reliable, but has not been independently verified. Therefore, HTM cannot guarantee its accuracy. Spyker Management LLP, HTM Energy, other affiliated personnel, or employees of HTM may have existing long, or short positions in the securities, or derivatives of the securities mentioned herein, and may purchase, or sell such securities without notice in the future.

The information disclosed within is, to the best of HTM knowledge accurate compiled and is presented based on the best available data and analyses at the time of publication. All estimates, projections, and assumptions, including those related to ultimate recoveries, well performance, production rates, breakeven prices, and other related metrics, are made based on current knowledge, industry standards, and available technologies. These figures are subject to inherent uncertainties and assumptions that may not fully account for real-world variables. The actual outcomes may differ materially from the estimates provided due to numerous factors that are outside our control. These include, but are not limited to, changes in market conditions, operational difficulties, variations in reservoir performance, evolving regulatory environments, and unforeseen technological or environmental challenges. Consequently, the estimates and projections presented herein should not be considered as guarantees or definitive indicators of future performance.

Unless otherwise noted, data disclosed in this document is sourced from, and interpreted by HTM Energy Research via various Government portals, data is retransmitted with permission under various license agreements. We do not assume any responsibility for errors, omissions, or inaccuracies that may arise from new data, unforeseen events, or changes in circumstances. Future results may also be impacted by external factors such as fluctuations in commodity prices, geopolitical developments, economic trends, and changes in demand for energy resources. Readers are advised to exercise caution and make independent evaluations and decisions based on their own judgment and the advice of qualified professionals. The estimates and projections are provided for informational purposes only and should not be relied upon as the sole basis for any investment, operational, or strategic decisions. Statements made within, including; estimated ultimate recovery figures for Teine Energy Duvernay wells; estimated ultimate recovery figures for Whitecap Resources Montney and Duvernay wells; estimated ultimate recovery figures for Bonterra Energy Montney wells; initial productivity estimates for Bonterra Energy Montney wells; estimated ultimate recovery figures for select Southern Alberta Bakken wells; estimated ultimate recovery figures for select Kelt Exploration and ConocoPhillips Montney wells; are made "as is" and without any warranties, either express or implied. While we have made reasonable efforts to ensure the accuracy and reliability of content, HTM makes no representations or guarantees regarding the completeness or accuracy of the information provided for any purpose.