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Rebound Affected Traps – Part 2: Migrated Accumulation Case Study

Lee, Robert, Independent researcher; Pedersen, Per K., University of Calgary.

Summary

This presentation looks at how observations from basin centered rebound affected traps may be used to understand accumulations of migrated oil which do not quite fit conventional expectations. Over 40 years working as a geologist in the Western Canada Sedimentary Basin, the lead author repeatedly noted oil pools which did not seem to fit with conventional models of migrated oil accumulations. Much of this work was focused on Mannville Group formations but similar observations were noted in other zones. This article focuses on understanding a recent Mannville oil pool discovery in central Alberta and why the initial test well "failed".

Workflow

The basic information about the pool is:

Formation:	Lloydminster
Facies:	NNW-SSE Shoreface
Thickness:	4-7 m
Average depth:	1100 m
Trap:	East-west bounding channels plus updip facies change.
Seismic:	Trade 2D - reprocessed
Log density porosity:	12-18 %
Permeability:	1-30 mD
Water Rw:	.08 ohm*m
Water saturation:	48-75%
Formation T°:	50° C
Formation P*:	~9,000 kPa
Oil gravity:	21° API
In situ viscosity:	~10 cP
Area:	>5120 Ha
OOIP resource:	~100 MM Bbls

The Mannville Group formations were correlated in every well across ~1200 Twps in central Alberta using the Lloydminster area stratigraphy. This pool was chosen for testing over other opportunities noted due to its areal extent. Most of the wells in the pool have good modern logs but the only cores available for the sand are small diameter ones from 1950's era Devonian test wells. The old cores are all very rubbly with most of the pieces less than 2.5cm long and abundant milling. The more cemented layers preferentially survived the coring process. No pieces were large enough for routine core analyses, but oil-stained, fine-grained sand was noted. Some samples were selected for mercury injection capillary pressure (MICP) measurements and XRD. The MICP indicated permeability up to 30 mD which meant not all the better rock was lost to milling. The Rw was defined using Pickett Plots of digital log data from several dozen wells across a few hundred Twp area and confirmed with the few high quality water analyses. There are very few oil analyses in the region and gravities ranged from 12°-26° API. Temperature data was taken from offsetting Ellerslie gas tests to calculate the geothermal gradient. These tests also gave guidance towards an initial pool pressure because none of the drillstem tests of the Lloydminster had sufficient buildup to extrapolate. There was a considerable range for temperature adjusted

viscosity due to the oil gravity uncertainty. Data from every Mannville PVT in a large region was tabulated to model for live oil viscosity. The live oil viscosity adjustment was favourable for any oil down to 15° API. One offset well had a weak neutron density log gas indication and another well tested gas on completion at higher elevations than the test well. There were excellent oil shows while drilling and gas ratios indicated solution gas only. The discovery well produced up to 25% oil cut at ~25% drawdown on test but gas influx limited the ability to draw the well down further. At 25% drawdown the water cut was too high. The fluid rates were within expectation. The carbon tax on flaring made extended testing prohibitively expensive.
The primary conundrum of this pool is the fluid saturations over the full +60m height of the pool are essentially transition zone. Elevated water saturations are not unusual for successful Mannville lithic sandstones.

Theory

Our earlier presentation on the aspects of basin centered rebound affected traps noted that porosity aperture dilation, imbibition, and low capillary film water mobility could be responsible for the broad transition zone saturations below the ultimate updip edge of the rebound affected Deep Basin region as predicted by Capillary Forces Theory (Lee et al., 2022). John Masters (Masters, 1979) observed that producing gas wells within the transition zone region updip of basin centered gas deposits typically show decreasing water cut over time. This indicates the volume of mobile water within the pore system of the transition zone is limited.
Burial history modeling of Alberta indicates maximum generation occurred in the Paleocene to Eocene during maximum burial (Higley et al., 2009; Matava & Barclay, 2025). Most of the available traps in western Canada were likely charged during the time of maximum generation. The beginning of uplift during the Eocene stopped generation (Higley et al., 2009). In low capillarity reservoirs, large pore apertures allow high fluid mobility so fluid saturations would adapt to changing conditions comparatively quickly. The oil-water contact may shift upwards to some degree. In high capillarity reservoirs, the capillary forces of smaller pore apertures generally restrict fluid mobility. Dilation would reduce the capillary pressure which would allow a limited volume of available water to recharge the capillary film while the oil remains trapped. This pool does not have a water contact so water supply would be limited.

Conclusions

The primary question is whether this pool could be produced economically with more optimal well placement. There are Mannville oil wells within the region which display decreasing water cut. Could the transition zone saturations in this pool have the potential to produce oil like the gas wells noted by John Masters (Masters, 1979)?

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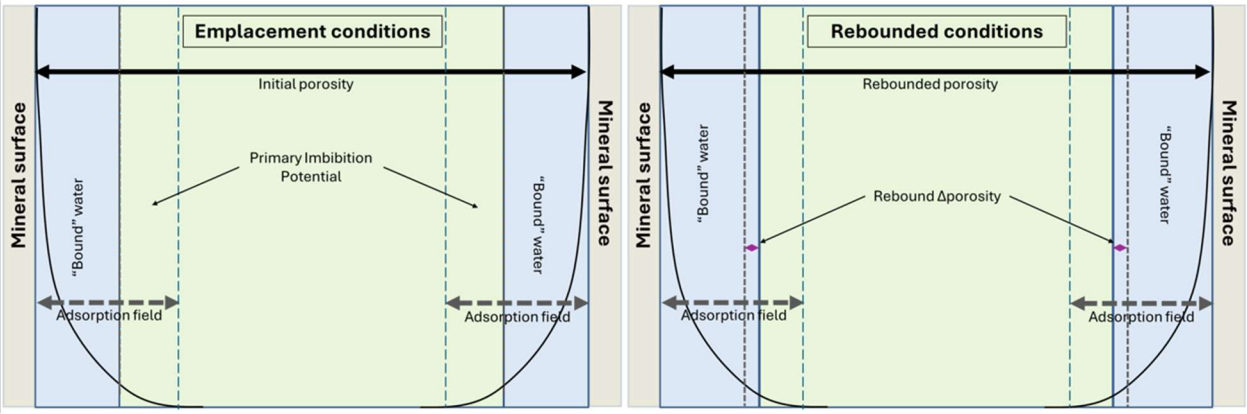


Fig. 1 The left diagram shows the saturation conditions at time of emplacement. Primary Imbibition Potential is present due to insufficient water and ions within the capillary film to balance the surface charge. The right diagram shows how pore fluids would redistribute in response to a decrease in capillarity (increase in pore apertures). There is no additional oil volume, so water preferentially fills the dilation space. During production, water becomes less mobile with depletion because of capillary forces.

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