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The Relationship Between a Naturally Fractured Carbonate Oil Reservoir and Production, From the Moose Rundle C Oil Pool, in the Alberta Fold and Thrust Belt.

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Introduction

The Moose field is located 100 kilometers southwest of the city of Calgary in the province of Alberta and underlies Moose Mountain. This mountain is a major topographic feature in the Foothills of the Canadian Rocky Mountain Fold and Thrust Belt.

Numerous underlying thrust faults repeat the Mississippian, Devonian and Cambrian age rocks in a duplex developed during the Laramide Orogeny. The structural style of the Moose field resembles that of several other significant hydrocarbon accumulations in the Canadian Rocky Mountain Fold and Thrust Belt (e.g. Waterton, Coleman, Savanna, and Limestone Mountain fields). These fields consist of multiple individual thrust sheets that control the distribution of the separate pools producing from reservoirs in the Mississippian and Devonian aged rocks. In the Moose field, the production comes from one or more thrust sheets beneath an overlying thrust sheet of Paleozoic rocks that are exposed at the surface. This is called the Moose Mountain Thrust Sheet and is carried on the Moose Mountain Thrust Fault (MMTF).

Existing production at the Moose field is from the Mississippian Turner Valley Formation, with minor production from the Devonian Palliser Formation. The production is from seven separate gas condensate pools (Rundle A, B, D, E, F, G and H pools) in addition to the Rundle C oil pool. (Figure 1)

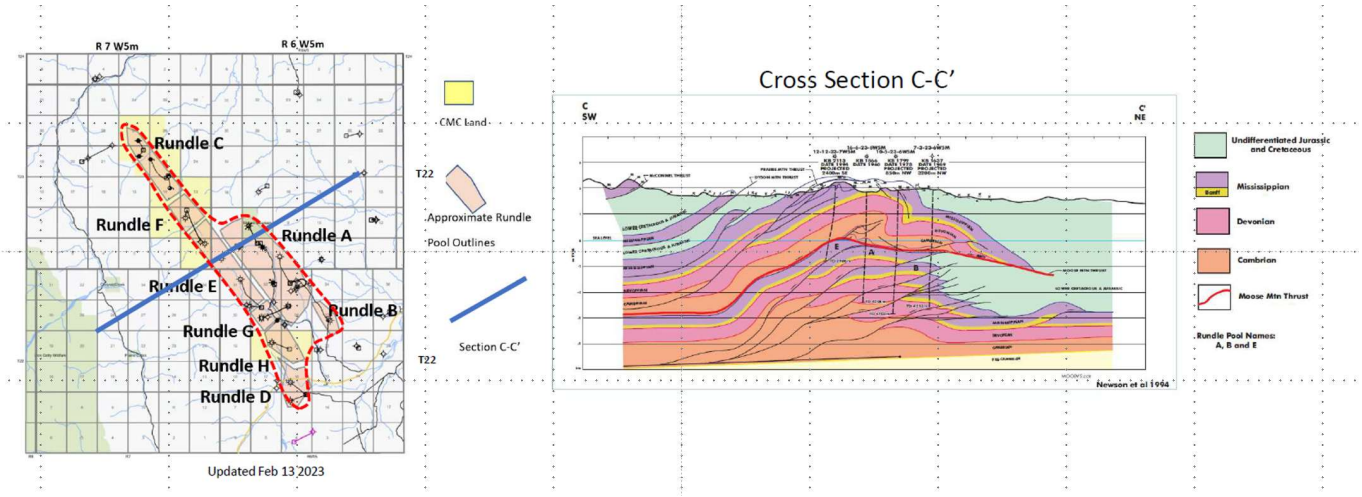


Figure 1: Cross section through the Moose Field that lies 100km SW of Calgary in the Alberta Fold and Thrust Belt. The Moose Mountain Thrust Sheet is exposed at the surface and is separated from the underlying Moose Duplex by the Moose Mountain Thrust Fault. The letters on the cross section represent the approximate position of the productive E, A and B pools.

The Rundle C pool is a separate pool to the NW of the main structure and is modeled here as a hanging wall anticline defined by the 6 key wells. (Figure 2)

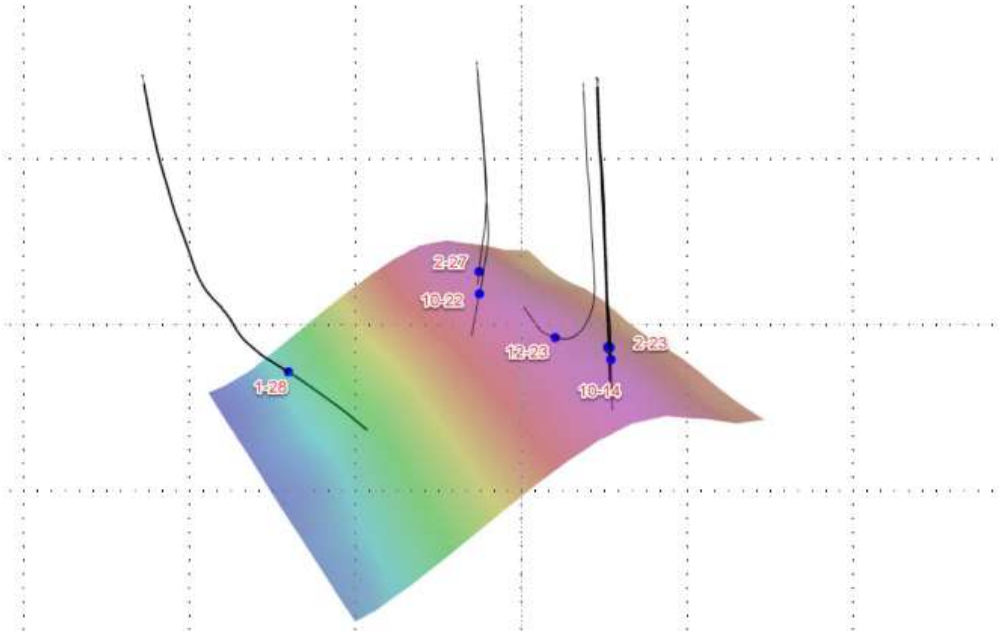


Figure 2: Looking north over a simplified model of the hanging wall anticline that defines the two way closure of the Mississippian aged Rundle Group reservoir. There are 5 oil producing wells and one untested well on the SW flank. All the wells are in Township 22 Range 6 west of the fifth meridian. NAD 83 Zone 11 UTM.

The productive Mississippian reservoir formation lies within the Rundle Group and consists of the Turner Valley formation. This formation is typically about 135m thick and is made up of the Upper, Middle and Lower members. It is characterized by porous dolomitized grainstones with pinpoint,

intercrystalline, and vuggy type porosity. Fractures are common throughout and are locally well developed. Dolostone, with secondary porosity resulting from dissolution of calcite forming moldic and intercrystalline porosity is also common in muddier intervals. The matrix porosities are on the order of 3-5+%, where enhanced by fractures. Permeabilities can reach as high as 100 md. Generally, permeabilities range between 1 and 10 md.

Geological Focus and Key Insights

Fracture System Characterization:

Detailed characterization of the fracture system was carried out through high-resolution core and image log analysis, allowing mapping of fracture azimuth, dip, spacing, aperture, and infill (Figure 3). In the 2-27 well, core fractures were directly compared with image-log interpretations (Figure 4). Fractures showing evidence of shear and dilation, characterized by rough, mismatched aperture walls in core, were identified as critical to enhanced porosity and permeability, and these fractures typically exhibited large image-log-derived apertures. Layer-bound, opening-mode fractures were also common; these fractures were generally close to perpendicular to bedding and frequently, though not always, terminated at bedding. In the image log, they commonly intersected the more horizontal fractures described above.

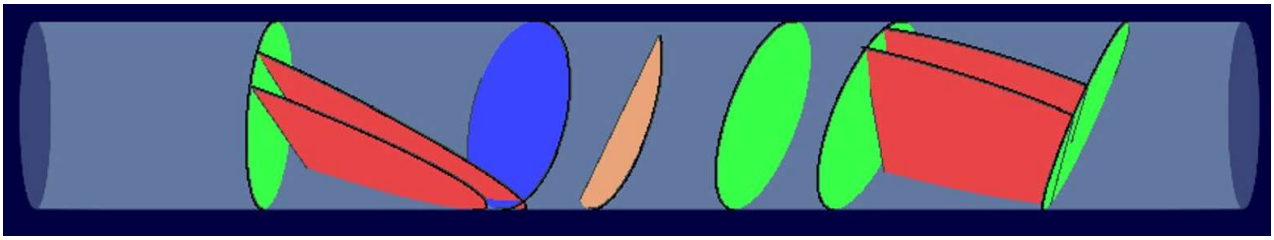


Figure 3. 3D core-style layout derived from a 2-27 image log. This image shows the borehole-enclosed fractures and beds. (The borehole diameter is about 22cm.) The fractures are red for layer-bound, blue for high-aperture, orange for partial but open fractures, while beds are green. The enclosed fracture area is used directly for calculation of fracture density (P32) by dividing it by the borehole-interval length. (For clarity, some of the fractures present in the image log are not shown.)

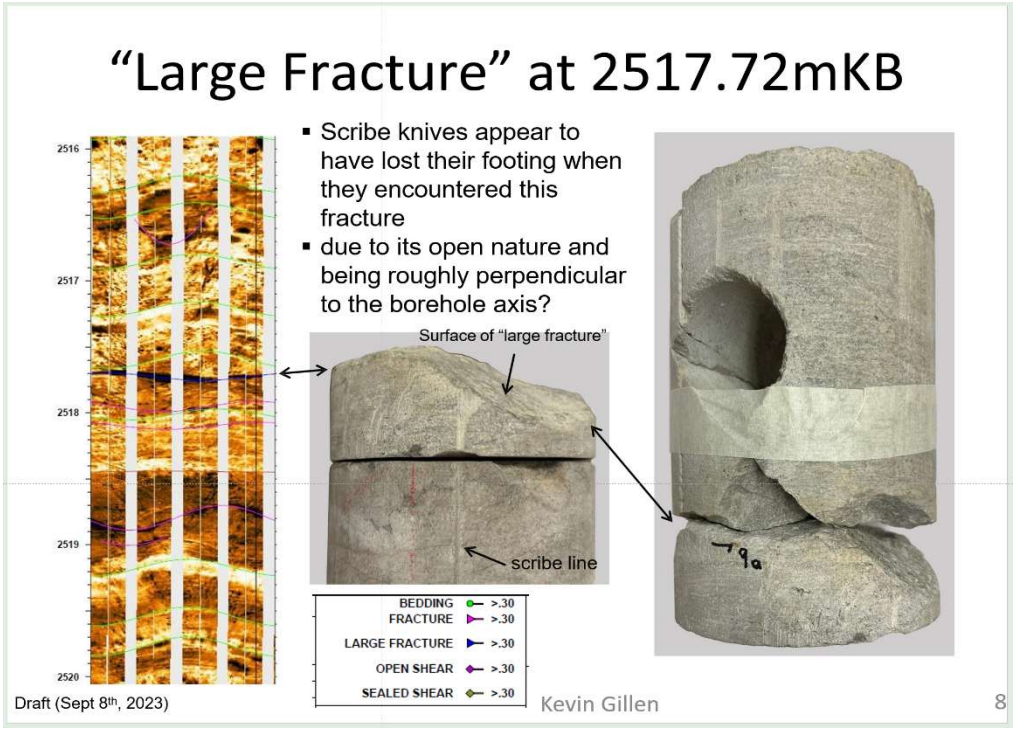


Figure 4: Detailed reconstructed core description matched to the image log in 2-27. Confidential Report by Kevin Gillen

Matrix and fracture porosity were quantified. The matrix porosity was calculated from a modern logging suite, but it proved difficult to find a consistent method that generated a good match to routine core analysis measurements. (Figure 5). The reservoir intervals displayed 3–5+% total porosity, with significant heterogeneity linked to fracture density and connectivity.

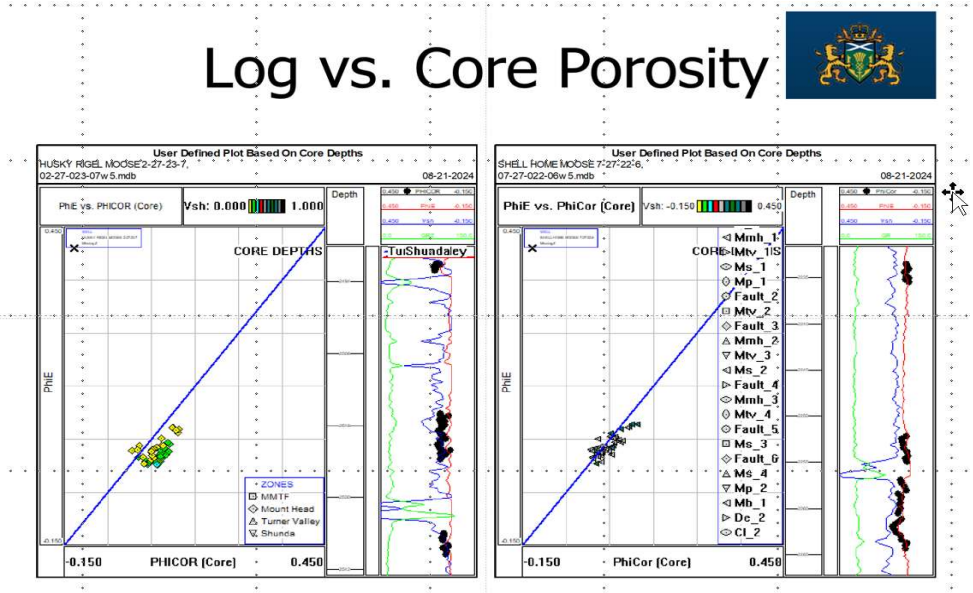


Figure 5: Examples from two different wells in the study, demonstrating the difficulty in matching nuclear-porosity from logs to Routine Core Analysis porosity measurements (Kisilevsky, 2024)

When image-log-derived fracture density (P32), size, and connectivity were calculated and calibrated to the core analysis, the results compared favorably with well production (Figure 6). Overall, the role of shear and dilation along fractures, and the associated enhancement of both porosity and permeability, is considered critical to production throughout the field.

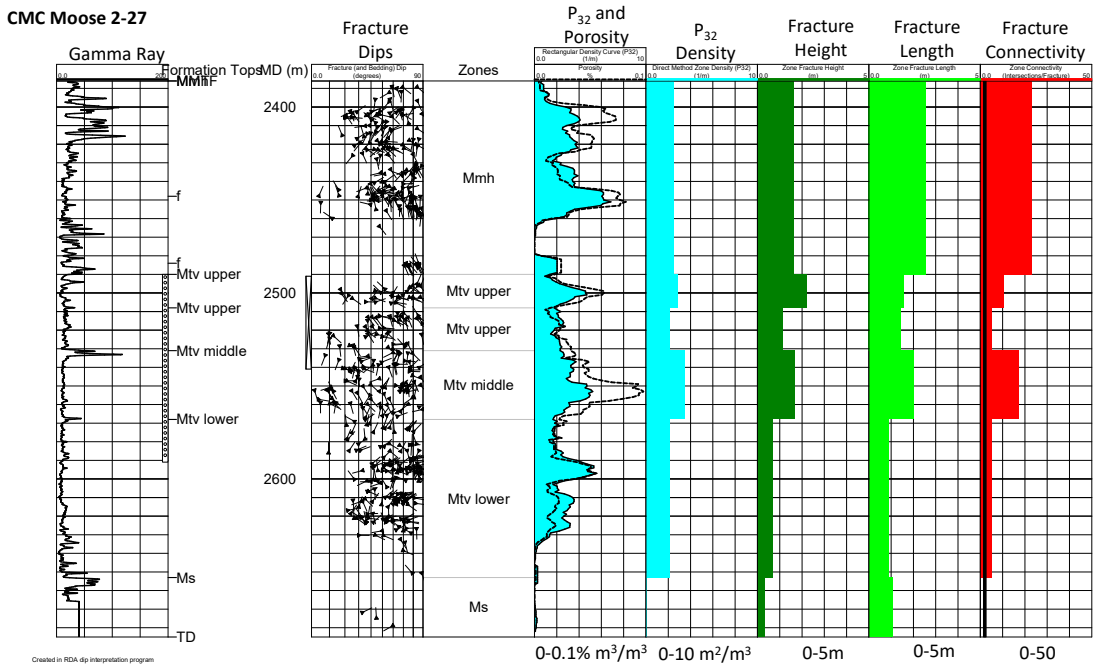


Figure 6: Fracture properties log. This log shows fracture density, porosity, height, length, and connectivity for the CMC 2-27 well. This well is significant in that it is a good producer and has both image log and cores, which allowed for calibration of the image log to the core. (When core corrections were applied, fracture porosities approached 0.5%. In addition, the high connectivity above 2490 m was not produced because of low matrix permeability.)

Outcrop Analogues and Structural Domains:

Field studies in the Alberta Fold and Thrust Belt established fracture distribution patterns by structural domain, serving as analogues for subsurface interpretation (Figure 7). Outcrop data revealed the persistence of type 1 and 2 fracture sets in dipping beds, informing models of secondary production halos and guiding expectations for flank well performance (Figure 8).



Figure 7: Moose Mountain, Southwest dipping back limb in outcrop with well-defined type 1 and 2 fracture sets within the grainstones of the Turner Valley formation. Newson et al (1996)

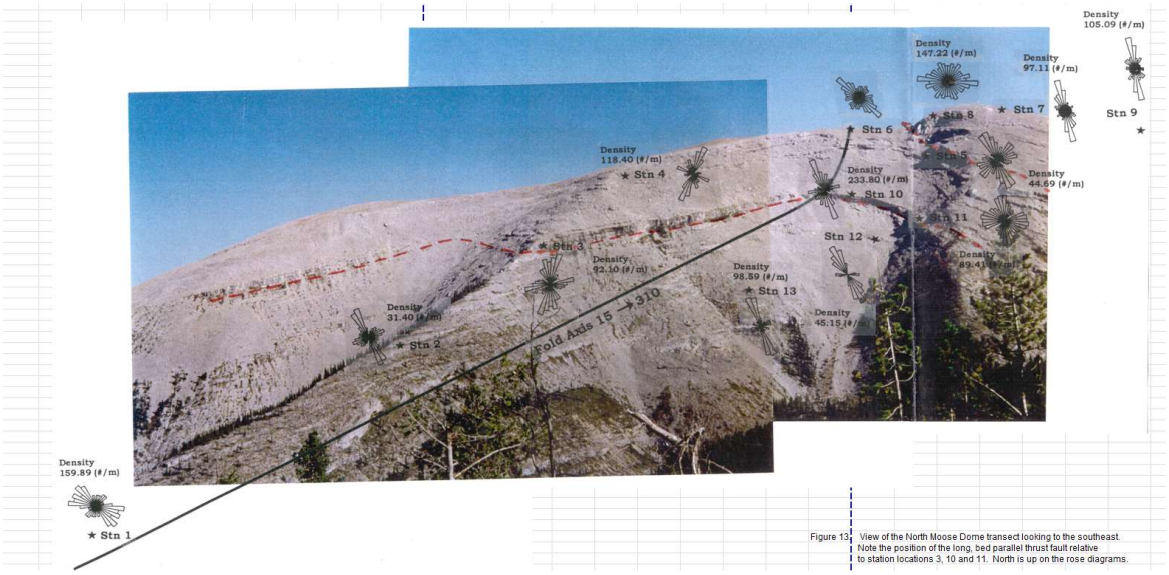


Figure 8: Looking southeast over Moose Mountain illustrating the low angle thrust fault geometry typical of the surface sheet. Billesberger (2000)

Integrated Subsurface Synthesis:

Integration of fracture, petrophysical, and production data enabled the mapping of dip domains and cumulative production trends (Figure 9). Comparative analysis with adjacent Moose Field

hydrocarbon production provided context for the evolution of fracture systems and their influence on reservoir behavior.

Well	Pool	Image log within the reservoir	Structural position	Fracture Density	Production	Highest rate of production	Fault within the reservoir	Reservoir quality	Overall Well Performance
2-27	C	Yes	Crest	3.66 m2/m3	687 Mbbl	529 Bbl/d	Yes	Good	Good
10-22	C	Yes	Backlimb/Crest	5.99 m2/m3	818 Mbbl	518 Bbl/d	Yes	Good	Good
12-23	C	Yes	Forelimb/Crest	15.84 m2/m3	1000 Mbbl	814 Bbl/d	Yes	Good	Good
2-23	C	Yes	Forelimb	1.97 m2/m3	104 Mbbl	194 Bbl/d	No	Good	Poor
10-14	C	Yes	Forelimb/Crest	1.5 m2/m3	46 Mbbl	75 Bbl/d	Yes	Poor	Poor
12-12	F	Yes	Backlimb/Crest	4.06 m2/m3	38 Bcf	9626 Mcf/d	No	Medium	Good
16-1	E	No	Backlimb	0.88 m2/m3	10 Bcf	4198 Mcf/d	Yes	Poor	Poor

Figure 9: Summary of the structural domain, fracture density, reservoir quality and well performance of the key wells associated with the Rundle C, F and E pool.

Geomechanical Behaviour and Reservoir Management:

A first-order geomechanical investigation was undertaken to assess the effects of reservoir pressure depletion and the concomitant in-situ stress changes likely to have occurred for different degrees of depletion (McLellan Energy Advisors Inc. 2024). Such stress changes are known to affect the porosity and permeability of naturally fractured carbonate reservoirs.

Basic data on the present-day in-situ stress magnitudes and orientations (Sv, SHmax, SHmin) and the reservoir pressure were compiled and analyzed for the Rundle C pool from well log and well test data from the field. Not all the desired stress data were readily available for the Moose Mountain field therefore analogs from other Mississippian and Devonian carbonate reservoirs were compiled from Alberta Foothills reservoirs previously reported in open literature.

A simple natural fracture re-activation model analysis was performed to examine possible scenarios for varying degrees of reservoir depletion, using reasonable stress path relationships from other carbonate reservoirs. Natural fracture statistics were compiled from core and log analyses undertaken by Vox Terra (2023), HEF Petrophysical (2023) and Berg (2019, 2021 and 2023).

Figure 10 shows an example of the drilling induced fractures (DIFs) that are parallel to SHmax in the 2-27 well between 1650 and 2680m MD. A mean SHmax azimuth of N41°E is found from this image log data. SHmax determined from three near-vertical wells ranged from 41° to 48°. Regional borehole breakout data in the Rundle Group gave an SHmax azimuth of N50°E (Bell et al,1994). SHmin magnitudes from analog minifracs in Mississippian TV and Devonian Wabamun minifracs ranged from 13.8 to 22.7 kPa/m, with a mean value of 18 kPa/m, prior to production.

Fracture re-activation analyses were performed with the Weatherford software STABView (2009) for 50% and 80% depletion cases and representative natural fracture orientations from core and logs from well 2-27.

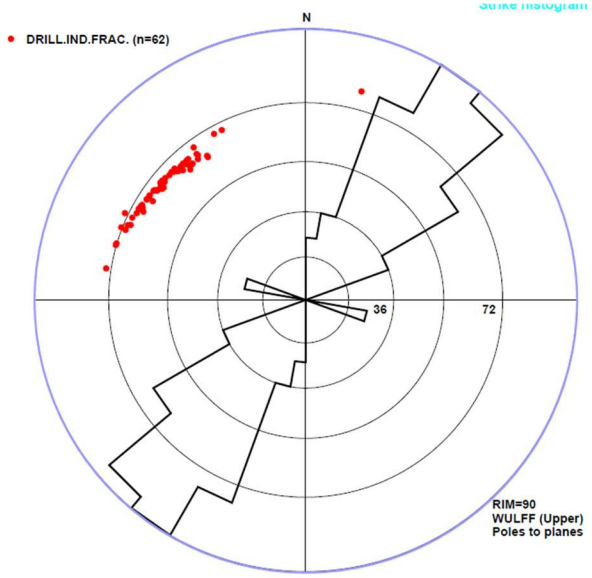


Figure 10: Rose diagram showing the orientation of drilling-induced fractures, parallel to SHmax, in well 2-27 between 1650-2680 m MD.

Figure 11: shows a colour contoured polar plot from STABView with values of the modelled pore pressure gradient required in natural fractures for all possible fracture orientations, that could result in shear slippage. Other analysis parameters used in the modelled case, for what is predicted to be a normal fault stress regime today, are shown in Figure 11. This case indicates that injection pressure gradients in excess of 10.8 kPa/m are required to cause natural fractures to slip. In other words, reservoir injection pressure gradients above this value during acid stimulations, waterflooding and/or EOR operations would be needed to re-activate natural fractures in shear. Note that a stress-aperture relationship for these Turner Valley natural fractures was assumed for this case, based on earlier laboratory work of McLellan (1993). However, this analog may or may not be appropriate for the Moose Mountain case.

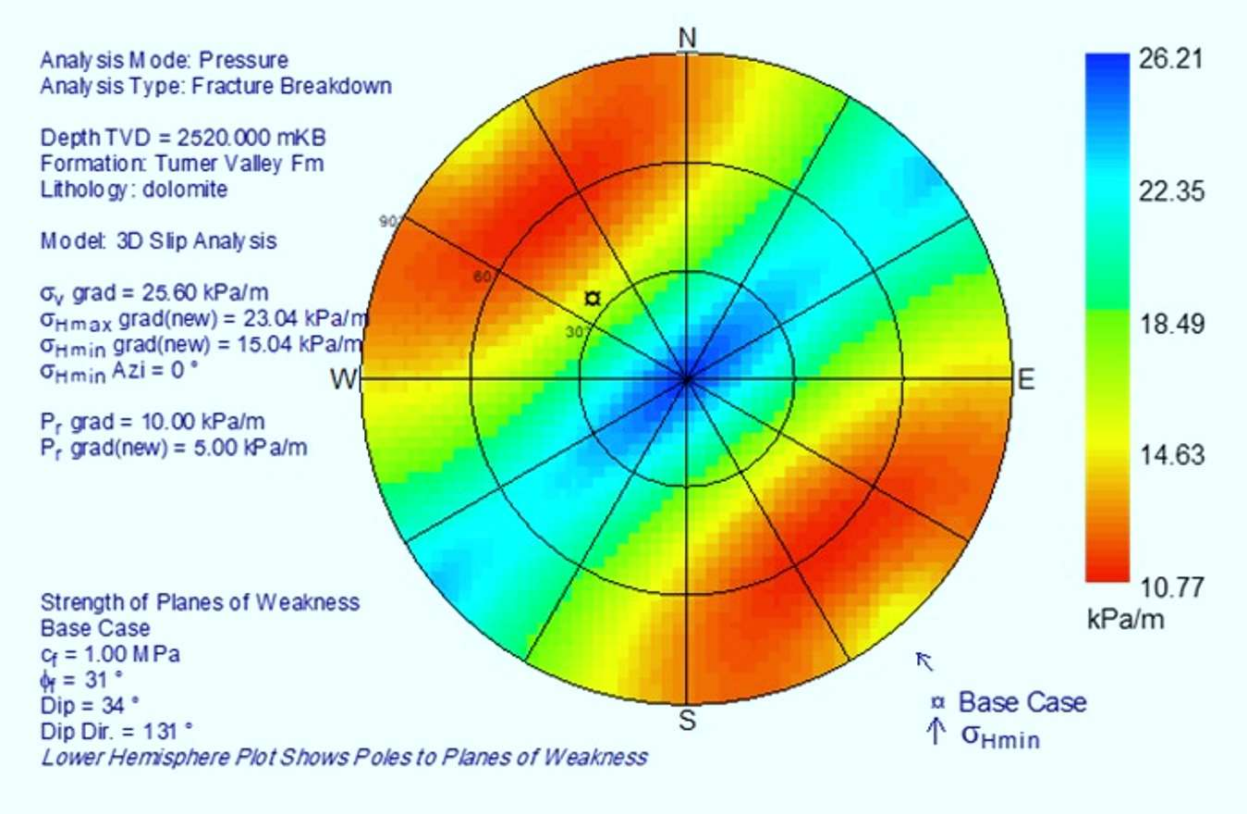


Figure 11: Polar plot from STABView showing injection pressure gradients required in natural fractures of all possible orientations to cause shear slippage.

In conclusion, scoping analyses using a basic geomechanical model for natural fracture re-activation suggest that there would have been no dilative behavior during classic reservoir pressure depletion, to levels of 50% depletion. However, it is predicted that injection processes in the depleted reservoir could cause dilative behavior and hence favorable natural fracture porosity and permeability changes during acid stimulation, waterflooding or EOR operations conducted today.

Geological Implications and Conclusions

The findings highlight the pivotal role of natural fractures in controlling fluid flow, storage, and production in carbonate reservoirs. The multidisciplinary workflow demonstrates the value of integrating geological, geophysical, and engineering datasets to accurately characterize fracture networks and predict their dynamic behavior. For geologists, this approach provides a robust framework for:

- Predicting fracture-controlled reservoir heterogeneity and compartmentalization.
- Informing well placement and completion strategies in structurally complex settings.

- Anticipating the impact of operational interventions on fracture permeability and reservoir performance.

This study reinforces the importance of analogue-based reasoning, structural domain analysis, and geomechanical understanding in the successful development of naturally fractured carbonate reservoirs in Fold and Thrust Belts.

Acknowledgement

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