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Application of sand percentage to evaluate fault seal risk

Robert Shoup[1,*], John Jong[2], Franz L Kessler[3]

[1] Subsurface Consultants & Associates, USA
[2] JX Nippon Oil and Gas Exploration (Malaysia) Ltd, Malaysia
[3] Goldbach Geoconsultants O&G and Lithium Exploration, Germany
*Corresponding author email address: rcs@clasticman.com

Abstract: In hydrocarbon exploration, establishing Allan Sections, calculating Shale Smear Factor and Shale Gouge Ratios are the few commonly applied methods for assessing fault seal risk. In this paper, an alternative approach is introduced to evaluate seal risk at the prospect scale by overlaying a sand percent map over the prospect structure map to help quantify seal risk along the fault trace. This approach effectively integrates all G&G data readily accessible to an interpreter during a prospect maturation process to narrow the seal risk uncertainty.

Keywords: Allan Sections, fault seal, sand percent, Shale Smear Factor, Shale Gouge Ratios

INTRODUCTION

Industry has traditionally relied on three methods to assess fault seal risk, Allan Sections (Allan, 1989), Shale Smear Factor (Smith, 1966, Weber *et al.*, 1978, Lindsay *et al.*, 1993), and Shale Gouge Ratios (Yielding *et al*., 1997). This paper will introduce a fourth method to evaluate seal risk using sand percent.

We will briefly review the use of Allan Sections and Shale Smear Factors to evaluate seal risk, and include a more thorough discussion of Shale Gouge Ratios since the sand percent method is a derivative of the Shale Gouge Ratio method. We will then discuss the application of sand percent to evaluate seal risk.

Several studies have shown that traps have a tendency to leak when the Shale Smear Factor is less than 3 and the Shale Gouge Ratio is less than 0.2. Conversely, traps are likely to work when the Shale Gouge Ratio is 0.4 or greater (Broussard & Lock, 1996, Bretan *et al*., 2003, Kessler & Jong, 2018).

ALLAN SECTIONS

The use of Allan Sections is based on the assumption that the fault itself has no sealing properties; the fault is not an open conduit; and the trapping and migration relationships at a fault depend upon the juxtaposition of sands across the fault (Allan, 1989). Impermeable beds juxtaposed against permeable beds are assumed to seal in structural closure whereas permeable beds juxtaposed against permeable beds allow hydrocarbons to spill across a fault. To assess the cross-fault juxtaposition relationships, cross sections are constructed along the hanging wall and the footwall of a faulted structure (Figure 1).

Allan Sections allow interpreters to see the relationship of the footwall stratigraphy relative to the hanging wall stratigraphy to assess the risk of cross-fault leakage. However, the assumptions listed by Allan (1989) are not universally true; there are a number of fields in which there are hydrocarbons tapped in fault blocks that are juxtaposed across from permeable horizons. As such, interpreters must use caution when using Allan Sections to assess seal risk. Nonetheless, it is generally true that the more permeable layers a horizon is juxtaposed across, the higher is the seal risk.

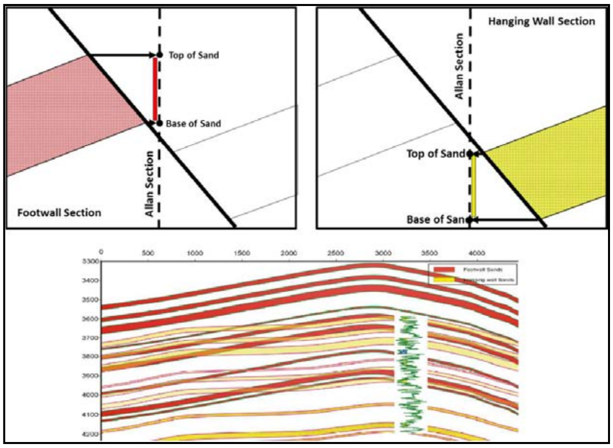

Figure 1: The Allan Section is a cross section constructed through the fault gap. The footwall and hanging wall horizons are projected on to the cross section normal to the section. When the footwall and hanging wall sections are displayed together we can see where permeable beds of the hanging wall are juxtaposed across the fault from permeable beds in the footwall (modified from Tearpock & Bishske, 2003).

SHALE SMEAR FACTOR

Shale Smear Factor (SSF) was first described by Smith (1966). He noted that clay was often smeared along the fault zone and that the smeared clay would inhibit fluid migration across the fault (Figure 2). The SSF is determined by dividing the fault throw by the thickness of the shale layer (Lindsay *et al*., 1993).

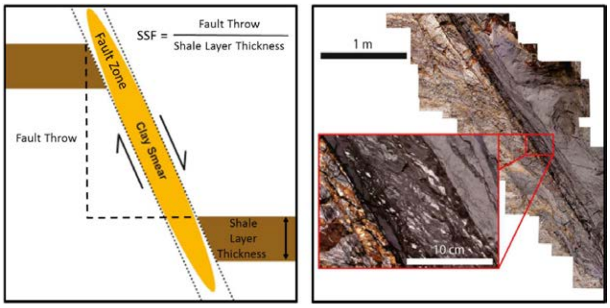

Figure 2: The Shale Smear Factor is a measure of the amount of clay material smeared along a fault zone (Smith, 1966). Clay smear observed in a fault zone near the city of Miri in Sarawak Malaysia (Vrolijk *et al*., 2015).

SHALE GOUGE RATIOS

Yielding *et al*. (1997) defined Shale Gouge Ratio (SGR), which is simply the percentage of shale or clay in the slipped interval. The more shaley the wall rocks, the greater the proportion of shale in the fault zone, and therefore the higher the capillary entry pressure (Yielding *et al*., 1997). More simply stated, the SGR is equal to the net shale in the interval offset by the fault (Figure 3).

OUTCROP AND SUBSURFACE SHALE GOUGE RATIO INVESTIGATIONS

The greater Miri area offers particularly well-exposed, world-class examples of fault geometry and clay gouging (Figures 4 and 5). Such information offers good material for studying fault architecture and clay smear morphology, and help to understand fault seal mechanisms in the subsurface (Kessler & Jong, 2017a & b). Field measurements of fault throws suggest that small fault throws result in thin layers of clay gouging, whereas large fault throws offer thick layers of clay smear (Figure 5). Such data can provide important analogues for predicting, or to simulating pressure and retention of hydrocarbon columns (Kessler & Jong, 2018).

In a recent study by Kessler & Jong (2018), it can be observed that within sand-prone shallow marine to intertidal settings, and a SGR of 0.1 to 0.2, fault sealing can be highly dependent on gouge texture, but in most cases commercial quantities of hydrocarbons cannot be retained with the resulting short hydrocarbon columns (Figure 6). On the other hand, within shale-dominated settings, such as the Sabah deepwater area, fault sealing capacity is high with SGRs mostly above 0.5. Furthermore, sand-to-shale juxtaposition along fault is more likely and leading to a high probability of retention (Figure 6).

This study indicates that for traps with a SGR of less than 0.20 traps rarely work. The traps that do work generally have column heights less than 50 feet. For traps with a SGR between 0.20 and 0.4, traps can work. Column heights range from negligible to 250 feet, but are mostly less than 50 feet. Traps having an SGR greater than 0.4 commonly work and often exhibit column heights greater than 200 feet. These results are similar to those observed by Broussard & Lock (1996), Yielding *et al*. (1997) and Bretan *et al*. (2003).

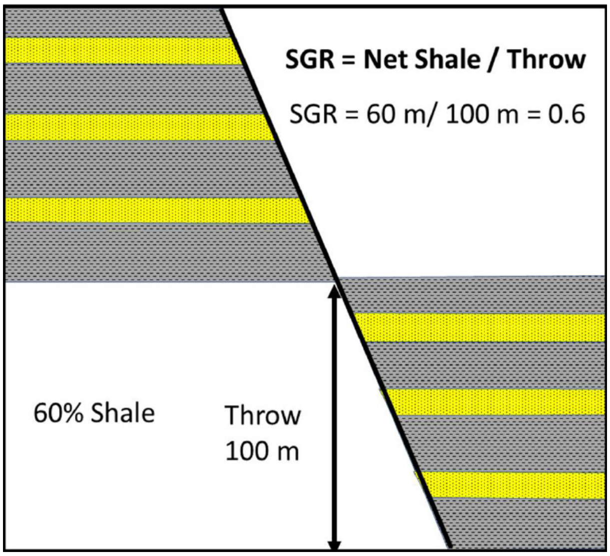

Figure 3: The Shale Gouge Ratio is equal to the net shale in the interval offset by the fault, i.e. net shale/throw.

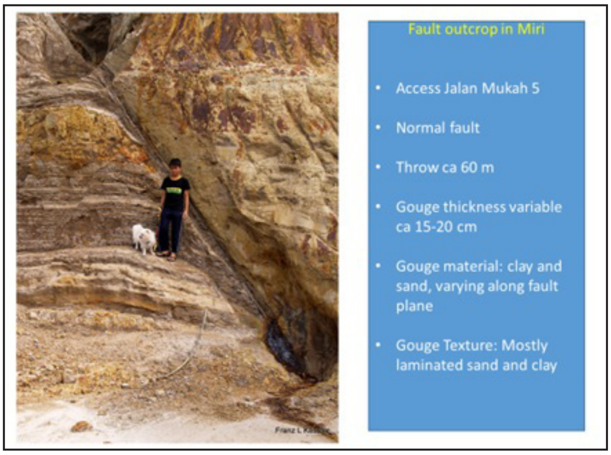

Figure 4: A normal fault on Miri's Canada Hill showing variable gouge material and texture with an estimated Shale Gouge Ratio of 0.3.

SAND PERCENT FOR RESERVOIR PREDICTION

Sand percent maps, alternatively known as Sand-to-Shale Ratio Maps or Net-to-Gross Maps, are a portrayal of the percentage of either total sand or net sand in a given gross interval. Sand percent maps have long been used to predict reservoir as they provide the interpreter with a map that illustrates the distribution of sand across the study area. The distribution of facies within clastic depositional systems is well understood from outcrop and modern depositional environment studies. This understanding can be used to generate sand percent maps even when there is limited well control.

When defining exploration play fairways, sand percent maps can be used to delineate the exploration sweet spot

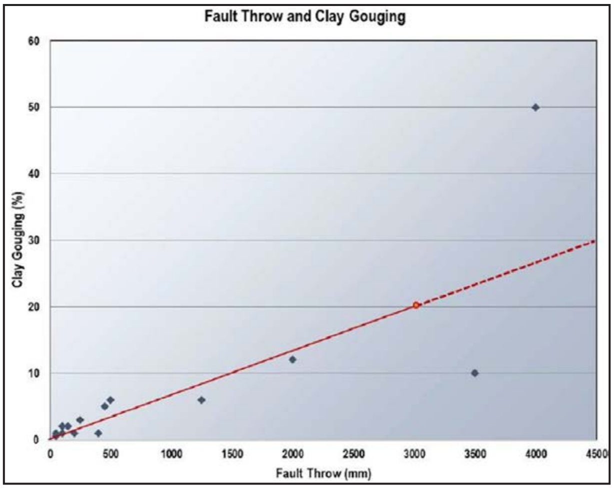

Figure 5: Measurements of clay gouging and fault throw taken from the shallow marine Neogene sedimentary outcrops located in Miri. Small fault throws result in thin layers of clay gouging, whereas large fault throws offer thicker layers of clay smear. Note the lack of data points for fault throws of more than 2000 mm resulted in an unreliable trend line for throw values of more than 3000 mm. However, this trend may be substantiated with more data, and may be useful to predict potential hydrocarbon columns in fault-traps (Kessler & Jong, 2017a & 2017b).

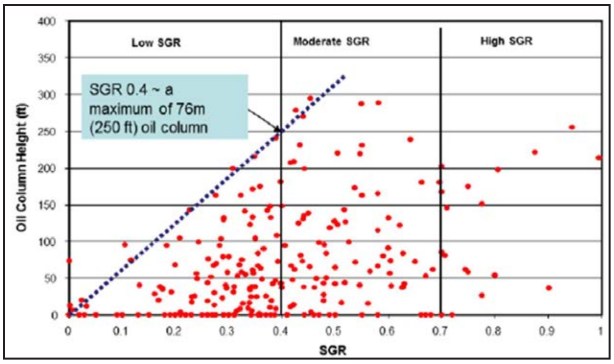

Figure 6: Oil column length (feet) versus SGR based on data compiled by Shell.

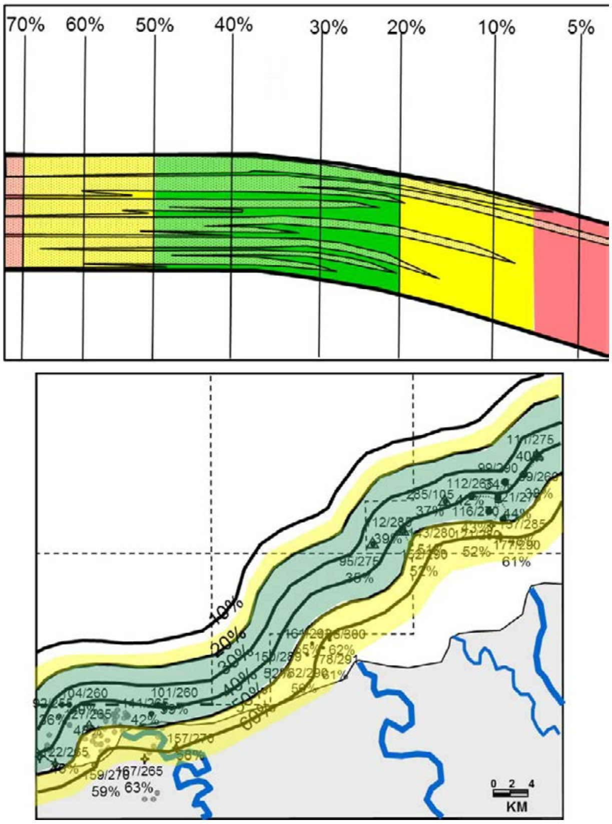

Figure 7: Sweet spot definition and play fairway map for a deltaic sequence. Where sand percent values are too low reservoir risk is high. Where sand percent values are too high seal risk is high. This means there is a reverse probability correlation between reservoir and seal.

(Figure 7). Reservoir risk increases in a downdip direction and seal risk increases in an updip direction. The play fairway lies between sand percent values of 7 or 70%. The play sweet spot is between 20 and 50%.

SAND PERCENT FOR SEAL PREDICTION

As we can see in Figure 7, we can use sand percent to help define seal risk in the play fairway scale. We can also use sand percent to help define seal risk at the prospect scale by overlaying a sand percent map on to the prospect structure map (Figure 8).

Where high sand percent values (>60%) intersect the fault, seal risk is high. Where sand percent values between 20 and 60% intersect the fault, seal risk is moderate, and where low sand percent values (<20%) intersect the fault, seal risk is low.

The application of this method can be illustrated for a prospect in the Texas Gulf Coast where two wells have been proposed to test Frio A and B reservoirs. The Frio B

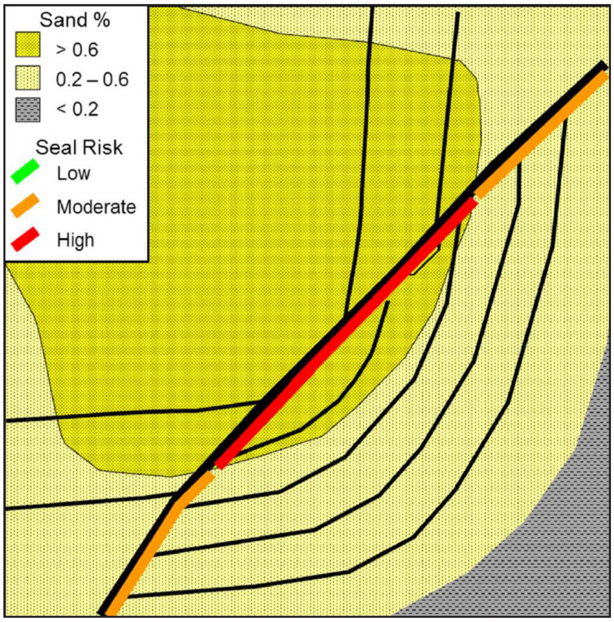

Figure 8: Sand percent map overlain with a depth structure map. Where high sand percent values (>60%) intersect the fault, seal risk is high. Where sand percent values between 20 and 60% intersect the fault, seal risk is moderate. Where low sand percent values (<20%) intersect the fault, seal risk is low.

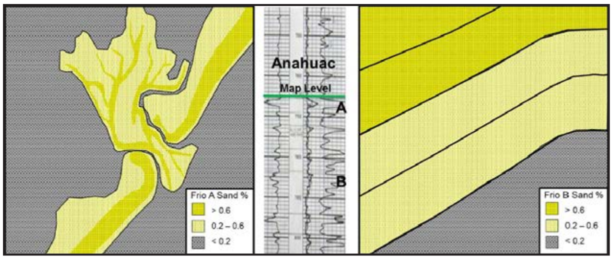

Figure 9: Sand percent maps for the Frio A (Left) and the Frio B (Right). The map level for the structure map seen in Figures 10 and 11 is the top of the Frio A. The Frio A was deposited in a barrier island and tidal delta environment. Frio B was deposited in a coastal strandplain just southwest of a wave-dominated delta. The Frio is overlain by the thick Anahuac Shale.

was deposited in a coastal strandplain and wave-dominated delta striking northeast to southwest (Figure 9). The Frio A is characterised as a barrier island and tidal delta sequence that formed when the Frio B was transgressed (Figure 9). The Frio A is overlain by the Anahuac Shale, which is over 500 feet thick in this location.

Looking first at the proposed Location 1, the trap is rollover anticline with a portion of the trap comprising a downthrown fault closure. The offset along the fault is such that the Frio A in the downthrown block is juxtaposed across from the Frio B in the upthrown block. To properly assess the seal risk, the Frio B sand percent map is overlain in the upthrown block and the Frio A sand percent map overlain in the downthrown block (Figure 10). The juxtaposition of the Frio A against Frio B sand percent values of 20 to 60% resulted in a moderate seal risk.

The trap for Location 2 is an upthrown fault closure. The offset along the fault is such that the Frio A in the upthrown block is juxtaposed across from the Anahuac Shale such that the seal risk is low (Figure 11).

One advantage of using sand percent maps to assess seal risk is that it also provides a map of the reservoir which can be used to plan exploration and development wells. It is possible to construct reasonably accurate sand percent maps ahead of the drill bit so long as the interpreter knows the depositional environment.

CONCLUSIONS

In hydrocarbon exploration, predicting fault seal risk for an effective trapping mechanism is as much an art as science. There are a few common methods established to assess fault seal risk, including Allan Sections, Shale Smear Factor and Shale Gouge Ratio, each with its own advantages and short-falls. In this paper we introduced an alternative approach for evaluating seal risk at the prospect scale by combining a sand percent map with the prospect structure map to help quantify seal risk along the fault trace. This approach integrates seismic, well, core analysis petrophysical parameters and field observations; data which are readily available to an interpreter during a prospect maturation process to lower the seal risk uncertainty.

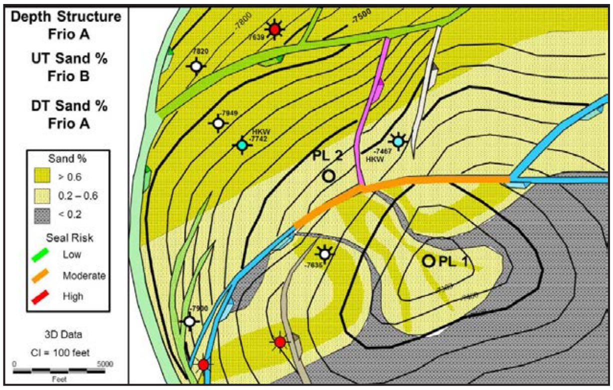

Figure 10: Overlay of the Frio A sand percent in the downthrown block and the Frio B sand percent in the upthrown block to assess seal risk for prospect location 1. Frio A sand percent of 40% and higher are juxtaposed against Frio B sand percent values or 40 to 60%, making the seal risk for location 1 moderate.

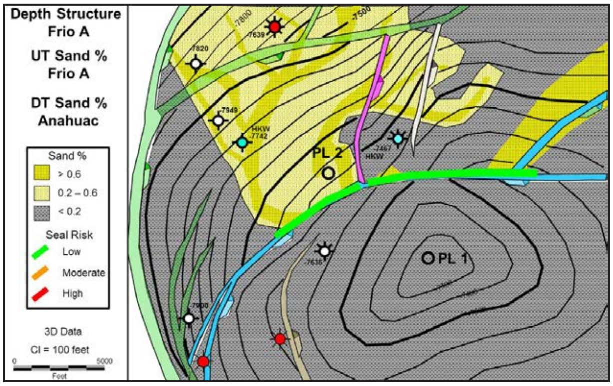

Figure 11: Overlay of the Frio A sand percent in the upthrown block and the Anahuac Shale sand percent in the downthrown block to assess seal risk for prospect location 2. Frio A sand percent of 40% and higher are juxtaposed against shale, making the seal risk for location 2 low.

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