

Impact of Subsurface Pressure Conditions on Caprock Structural Integrity and Retention Capacity in Petroleum Systems

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Abstract: *Pore pressure significantly influences prospect evaluation by driving mechanical top-seal failure under low vertical effective stress, preserving reservoir porosity through overpressure, and increasing drilling costs for high-pressure traps. Hydrocarbons may be preserved in regions with elevated overpressure, provided a protected trap exists with a caprock or upper seal of adequate mechanical strength. Understanding the geology is critical because it defines the subsurface pore and fracture profile and, in turn, helps predict a trap's sealing and retention capacity. As onshore exploration extends to greater depths and offshore exploration moves into deeper waters, understanding seal performance has become essential. The paper discusses a workflow for assessing trap headroom capacity and demonstrates, through a Far East example, how it aids hydrocarbon exploration.*

Keywords: Seal integrity, Reservoir seal pair, Top seal, Protected trap, Mohr's envelope, Headroom and Retention Capacity

1. Introduction

Accumulation and retention of hydrocarbons within a structural trap depend upon access to charge and the presence of a lateral seal and top seal¹. Given these are in place, it is the interplay between retention and charge that determines the height of the hydrocarbon column². Access to a mature source rock and hydrocarbon migration into a trap control charge, whereas the integrity of the cap rocks and sealing faults controls retention. Pore fluid pressure exerts a significant influence on prospect evaluation through three principal mechanisms:

- 1) Potential mechanical failure of the top seal under reduced vertical effective stress (VES), necessitating a structurally protected trap for commercial viability;
- 2) Preservation of reservoir porosity under overpressure; and
- (3) the financial implications of drilling in high-pressure environments.

The industry has long recognised the correlation between anomalous pressure regimes and hydrocarbon accumulations. To maintain top-seal integrity, pore pressure at the structural apex of a reservoir must remain below the mechanical capacity of the overlying caprock. Given the substantial capital investment required to drill oil and gas wells, assessing hydrocarbon prospects with particular attention to top-seal integrity is a prudent, systematic approach to prospect appraisal. As onshore exploration targets move deeper and deepwater targets become more complex, understanding seal behaviour is no longer optional- it is fundamental.

2. Seal Integrity Concept

Seal integrity is the sealing rock's ability to resist the buoyant pressure of hydrocarbons without allowing them to leak. This ability is primarily determined by two key parameters:

- 1) Capillary entry pressure (Pc): The minimum pressure required for hydrocarbons to displace water and enter the pores of the seal.

- 2) Mechanical strength: The rock's ability to resist fracturing under stress or differential pressure.

Top seal capacity is a critical factor in trapping hydrocarbons in the subsurface. The interplay of fluid forces, rock properties and stresses governs top seal integrity and capacity. Should the buoyancy pressure exerted by the confined hydrocarbons surpass either of these thresholds, leakage may transpire via capillary failure or fracturing. A top seal can fail when pore fluids exceed either the capillary entry pressure threshold or the seal's mechanical failure strength. The paper mainly discusses mechanical strength, which is directly related to the potential for hydrocarbon column accommodation. The retention capacity of any confining system, whether a conventional shale seal or a composite system, has its limits. For conventional shale seals, this is usually expressed in terms of pressure differential or column height, which can be converted to volume given knowledge of the trap geometry³. For composite confining systems, system thickness and average barrier length are good starting points, but converting to retention volume requires modelling, including sensitivity analysis.

Geologic work must focus on the characteristic seal problems that affect different classes of prospects. Anticlines have relatively low seal risk because any layer that acts as a top seal will also provide a lateral seal. Stratigraphic traps and faulted prospects, however, carry substantial seal risk⁴.

3. Top Seal Failure Analysis

A laterally continuous seal can fail when fluids overcome either the capillary entry pressure or the seal's mechanical strength⁵. Mechanical seal failure occurs when the pore pressure exceeds the fracture pressure. If pore pressure reaches fracture pressure due to hydrocarbon buoyancy, the trap will be limited in column height. If the brine aquifer pressure reaches fracture pressure, then the trap is "blown" (Figure 1) and unable to retain a hydrocarbon column. Seal failure occurs when pore pressure exceeds the fracture

pressure, defined as the minimum principal stress plus tensile strength. Even with elevated vertical effective stress (VES)

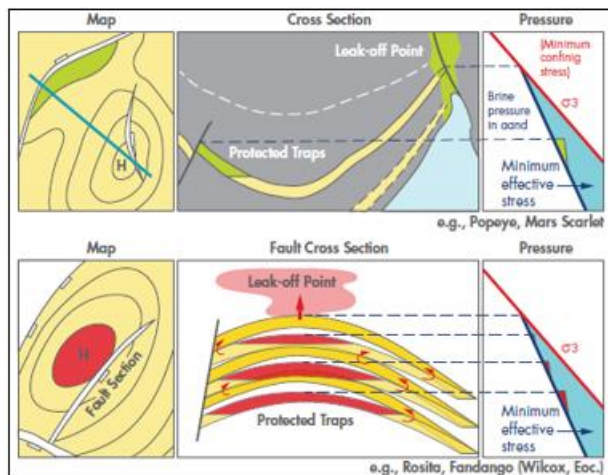


Figure 1: Commonly occurring protected traps⁶

and accounting for the hydrocarbon column's influence on the brine pressure profile- which corresponds to shale pore pressure- top seal breach typically does not occur. However, a narrow window between pore pressure and fracture pressure often cannot accommodate a substantial hydrocarbon column or maintain an intact trap, as numerous documented cases show. This challenge is exacerbated in deepwater shallow reservoirs, where the VES is inherently constrained. Figure 2 presents a conceptual illustration of a hypothetical penetration scenario at the trap crest in a deepwater environment. A wider VES and a pressure window between pore pressure (PP) and fracture pressure (FP) keep the hydrocarbon column stable. Figure 3 shows trap breaching under the same hypothetical conditions, caused by a narrower VES and a narrower PP-FP window.

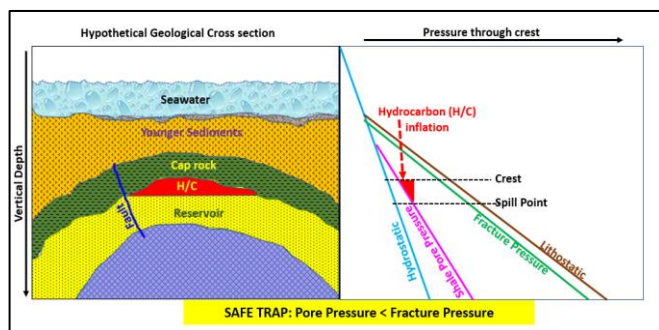


Figure 2: Pressure profile along a well trajectory drilled through the crest. Hypothetical situation for a safe top seal.

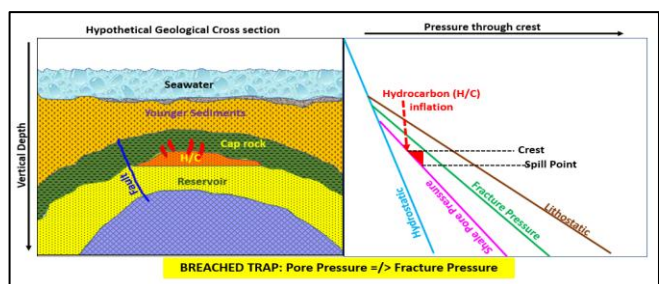


Figure 3: Pressure profile along a well trajectory drilled through the crest. Hypothetical situation for a breached top seal.

Hydrocarbons may be preserved in regions with elevated overpressure, provided a protected trap exists with a caprock or upper seal of adequate mechanical strength. In deepwater environments, shallower reservoirs may offer opportunities if the seal exhibits plastic geomechanical behaviour.

A single geological formation may contain multiple vertically stacked reservoirs separated by intervening seals. These configurations are known as alternating reservoir-seal pairs (RSPs). Numerous examples show that shallower reservoirs may be breached (Figure 4).

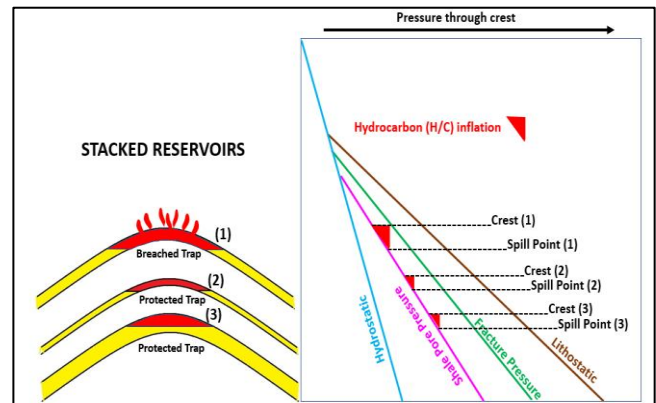


Figure 4: Breached and protected traps in stacked reservoirs

In 1992, Tennant⁶ demonstrated the locations of traps in pressure communication with shallower leak points, where aquifer pressures equal the top seal fracture pressure (Figure 5). These traps are protected from mechanical failure of the top seal by adjusting fluid pressure according to the shallow top seal leak pressure⁷.

Compaction depends on virgin VES (or maximum VES) and therefore influences reservoir porosity forecasting. Unlike seal-failure scenarios, reduced VES favours preserving reservoir porosity. Consequently, an optimum VES emerges,

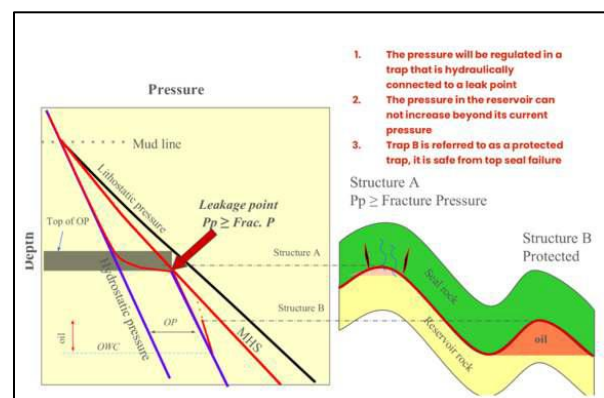


Figure 5: Top seal integrity and hydrocarbon accumulation⁷

low enough to maintain adequate reservoir porosity yet high enough to prevent seal compromise and fluid loss, termed a 'sweet spot'. Conversely, excessively high VES is detrimental, as reservoir quality deteriorates as porosity declines (Figure 6).

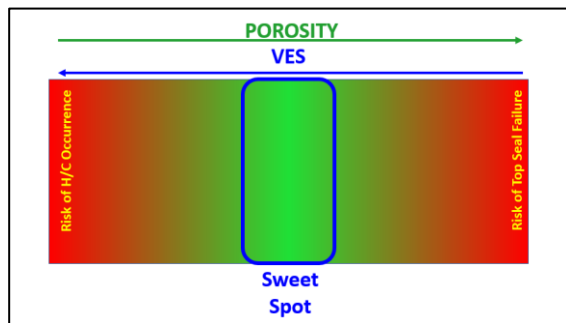


Figure 6: Schematic diagram showing interplay between VES and reservoir porosity.

4. Influence of Geology and Overpressure Generating Mechanism

The pore-pressure profile configuration is critical to assessing a trap's susceptibility to breach. Investigations into the fundamental determinants of this profile's configuration show that it is intrinsically linked to both the sedimentary depositional setting and the mechanism responsible for overpressure generation.

The pore-pressure distribution, and consequently the classification of pressure-gradient characteristics, depends on the region's geological evolution, which may include tectonic influences or the spatial arrangement of lithofacies. The following examples illustrate how geological factors shape pressure-gradient patterns. Two examples of geological influence on pressure-ramp shape are as follows:

Marine Depositional Setup: In a typical marine depositional setting, eustatic changes that drive progradation and retrogradation of shelf sediments will vary the facies distribution. Shelf areas dominated by coarse, permeable clastics show hydrostatic or near-hydrostatic pore-pressure profiles to greater depths, beneath which thin layers of pressure seals (shales) may cause a steep pressure ramp-up. With increasing water depth, impermeable layers dominate, overpressure becomes more gradual, and pore-pressure profiles become parallel to overburden pressure⁸ (Figure 7).

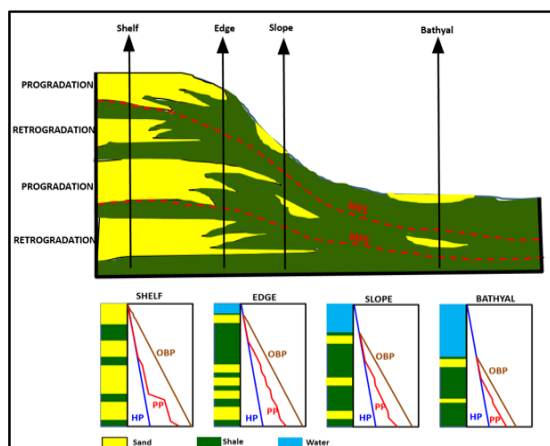


Figure 7: Schematic of the variation in subsurface pore pressure profiles with changing lithofacies along a cross-section extending from shelf to bathyal environments; MFS = maximum flooding surface⁸

In lateral plumbing systems where reservoir sands lie beneath the centroid and maintain robust connectivity or plume pathways to a shallower discharge point within the basin, protected traps form (Figure 8).

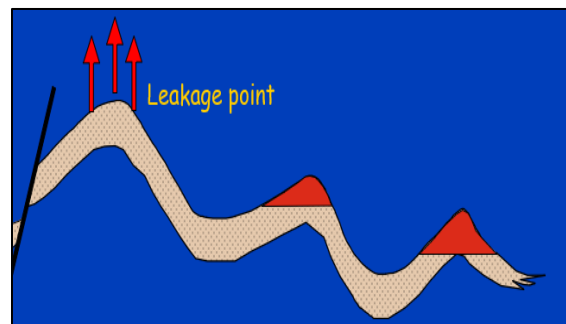


Figure 8: Deeper traps connected to shallow leak points.

In these settings, the shallower discharge point effectively 'shields' the deeper traps below the centroid, exemplifying the classical protected-trap architecture (Figure 9).

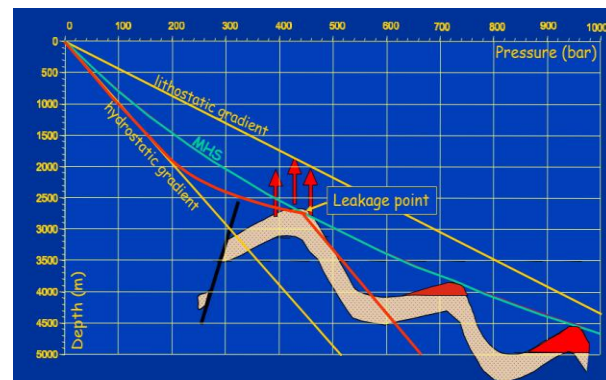


Figure 9: Pore-Fracture profile of Deeper traps connected to shallow leak points.

This configuration produces a markedly different pressure response. Effective stress rises substantially within these protected traps, which typically fill to spill capacity and can contain extensive hydrocarbon columns. Conversely, the shallower discharge point sustains minimal effective stress. These seals are designated as hydrodynamic seals, marking a marked departure from the elevated-pressure crest behaviour. Lateral fluid flow affects the sealing capacity of sandstone reservoirs and the variable position of hydrocarbon-water contacts around a structural accumulation. This requires considering each sandstone-shale couplet (reservoir-seal pair, RSP) separately for pore pressure prediction⁹.

The composite structure and geological transect (Figure 10) illustrate a deeper protected trap connected to a shallow trap that leaks and adjusts, thereby supporting the deeper accumulation in offshore Brunei in the Far East.

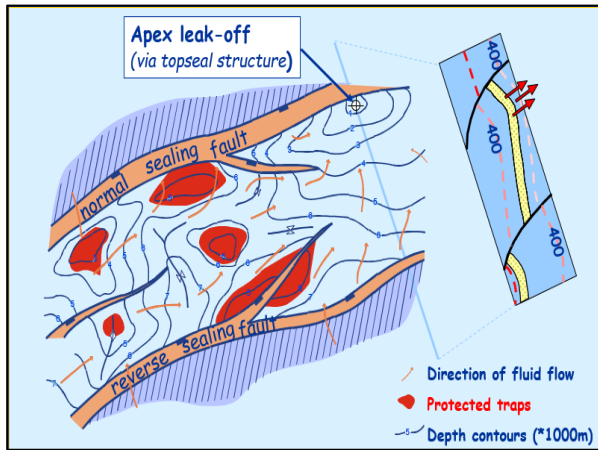


Figure 10: Occurrence of Deeper traps connected to shallow leak points

Uplift and erosion: In a post-depositional marine setting, sediments uplifted by tectonic plate movement are exposed above mean sea level. This exposure leads to erosion of the surface. After a hiatus, deposition resumes over the eroded surface. The sediments deposited after this event may or may not show imprints of any further tectonic activity. In many cases, the tectonic imprints in these two episodes differ and can be clearly distinguished in the field or in geophysical data by an angular unconformity.

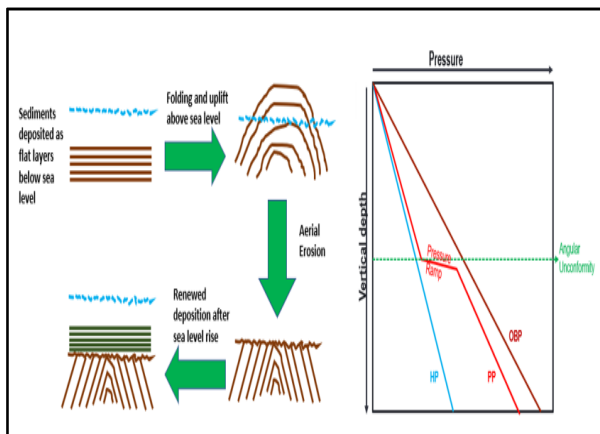


Figure 11: Unloading leading to steep pressure ramp

Uplift and erosion transfer deeper pressures vertically with less overburden. The pressure ramp in this situation is usually a steep pressure ramp. This process is also known as unloading (Figure 11).

Overpressure-generating mechanisms directly control the shape of the pore-pressure profile. Although there are various reasons for overpressure generation, they can be broadly categorised into two types: a) Type-1 (loading or disequilibrium compaction) and b) Type-2 (unloading) (Figure 12).

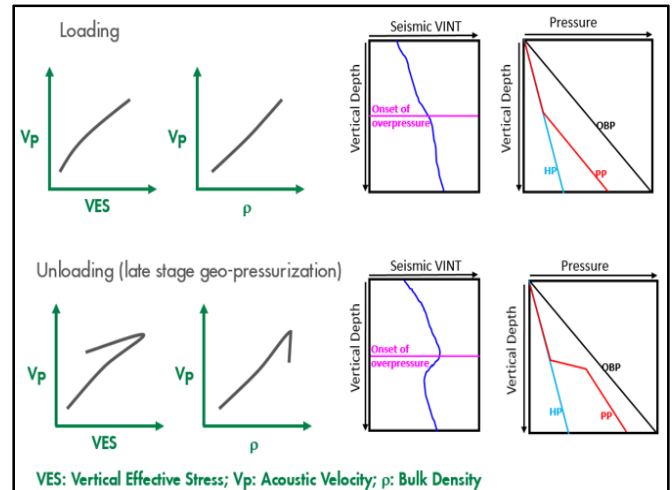


Figure 12: Responses to different pressure generating mechanisms

5. Fracturing Behaviour of the Top Seal

As with the overpressure mechanism, understanding the leakage type and top-seal fracture behaviour is vital to a comprehensive analysis of top-seal failure. Fracturing is generally categorised into three types: extensional fractures in overpressured brittle mudrocks, dilatant shear fractures in moderately pressured brittle-ductile mudrocks, and non-dilatant shear fractures in high-pressure ductile mudrocks.

Figure 13 schematically illustrates the top seal's fracturing behaviour using Mohr's Circle. As pore pressure increases, both the effective maximum and minimum principal stresses decrease, causing the Mohr circle to move into the tensile failure zone (Mohr circle 1, left of the shear stress line). The criterion for triggering extensional fracture in a top seal is "Pore Pressure is equal to or greater than the minimum principal stress + tensile strength". In this case, the minimum horizontal stress is taken as the minimum principal stress. In some cases, shallower brittle-ductile (semi-brittle or semi-ductile) mudrocks that are moderately pressured and deform under low-confining-stress regimes exhibit dilatant shear fractures (Mohr circle 2 in Figure 13).

The limiting criteria for triggering dilatant shear fracture is $\sigma_1 = 2 \cdot C \cdot F \cdot 0.5 + F \cdot \sigma_3$

where σ_1 = Maximum Effective stress (vertical effective stress in this case); σ_3 = Minimum effective stress (effective stress between minimum horizontal stress and pore pressure); C = cohesion; F = friction factor, $F = [(1 + \mu^2) \cdot 0.5 + \mu]^2$.

Where μ is the coefficient of friction and is equal to the tangent of the friction angle.

The third type of fracturing, i.e., non-dilatant shear fractures, occur during deformation at high confining pressures (under deep burial) or in weak, ductile rocks with a low friction angle. The non-dilatant shear fractures will remain closed and sealing after deformation¹⁰.

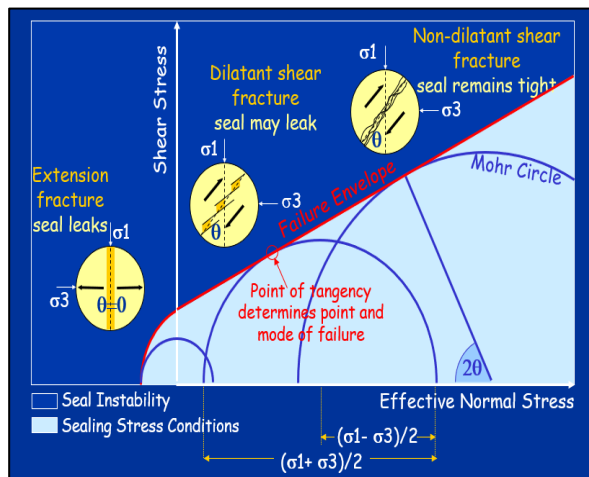


Figure 13: Failure criteria per Mohr's envelope

Given that non-dilatant shear fractures have negligible effects on hydrocarbon leakage in a ductile caprock, we will proceed with the other two fracture types for the top-seal failure discussion.

Before determining which fracture type can occur, it is critical to know whether the caprock is ductile or brittle. Fundamentally, the tendency to dilate depends on (1) the rock's mechanical properties, (2) effective stress and (3) shear-zone geometry. At a given effective stress, a stronger, brittle (over-consolidated or cemented) rock is more likely to dilate than a weaker, ductile rock. Three methods may be used to estimate embrittlement in mudrocks⁹:

a) **Over-consolidation Ratio (OCR):** This is the ratio between maximum effective stress in geological history and the current day history stress. In this paper, we treat vertical stress as the maximum principal stress.

$$OCR = VES_{max}/VES_{current}$$

This index also measures uplift and erosion. In ductile rocks, the ratio is significantly higher than unity, as the maximum VES is not the current VES. In brittle rocks, the current VES is usually the maximum value in the geological history, or the maximum VES is only slightly higher than the current VES,

So, the index is close to unity.

b) **Mudrock Brittleness Index (BRI):** This index is a ratio between the unconfined compressive strength of the zone of interest (UCS) and the UCS of normally pressured mudrocks in the region (UCS_{nc}).

$$BRI = UCS/UCS_{nc}$$

UCS can be derived from core data or calibrated well-log-based Mechanical Earth Model (MEM). UCS_{nc} can be established by fitting it to the UCS of normally pressured shales at the location or well. If no data is available, Horseman et al.¹¹ proposed an empirical relationship: $UCS_{nc} = 0.5 * NES$, where NES is the normal effective stress (effective stress between vertical stress and hydrostatic pressure). If BRI is greater than 2, the risk of embrittlement increases.

c) **Friction Angle from surface area or gamma ray:** Ingram and Urai¹² established an empirical relationship between the internal friction angle (ϕ) and the specific surface area (S) of

mudrocks. This relationship shows that the friction angle decreases logarithmically as specific surface area increases, reflecting how clay mineralogy and related physicochemical properties affect mudrock shear strength. The friction angle can be estimated using the following expression:

$$\text{Log}(\phi) = \text{log}(35) - S * (\text{log}(35)/1266)$$

Estimating surface area from DCM or drill-cuttings data often has a high margin of error and may therefore be inaccurate. Surface area and friction angle also relate to gamma ray (GR) and can be estimated from gamma ray logs, which have a relatively small margin of error. The relationship between friction angle and GR is shown in Figure 14.

Ingram et al.¹⁰ defines ductile rocks as having a surface area greater than $300 \text{ m}^2 \text{ g}^{-1}$, corresponding to $\phi < 14^\circ$ and GR > 150 API.

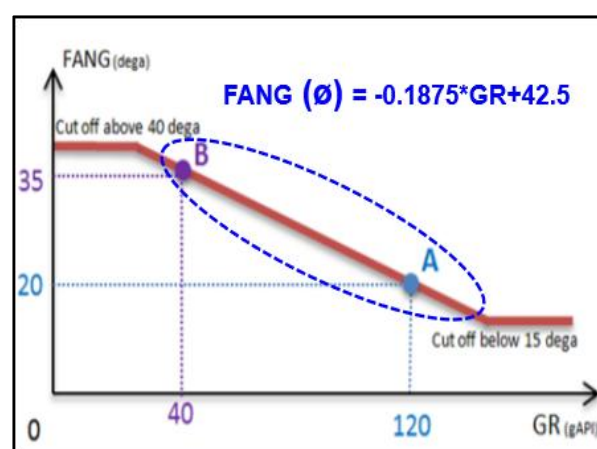
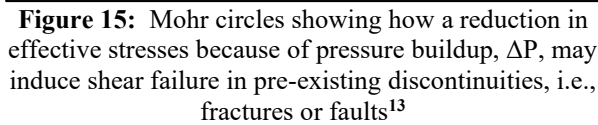


Figure 14: Relationship between GR and Frictional angle

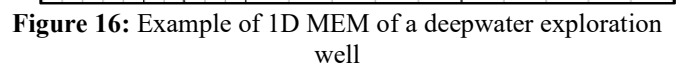
So far, we have focused on fracturing mechanisms within intact cap rocks. How would the geomechanical conditions differ if the seal were compromised by faulting or existing fracture systems? When pre-existing faults or fractures create pathways between the reservoir and the cap rock, they typically contain fluids that reduce both cohesive strength and frictional resistance.

Geochemical processes may modify fault frictional properties, potentially triggering failure if the fault becomes sufficiently weakened¹³. In rocks containing pre-existing failure surfaces, cohesion is typically treated as negligible or absent. According to Byerlee¹⁴, intact rock has a friction coefficient (μ) generally between 0.6 and 0.85, depending on the effective normal stress. By contrast, rocks containing faults or pre-existing weakness planes show lower friction coefficients, typically ranging from 0.3 to 0.6. Consequently, the failure envelope in Mohr's circle shifts to the right and has a slightly different slope from the failure line for intact rock (Figure 15).



- Thorough analysis of the fracturing behaviour of cap rock;
- Rock-property modelling; and
- In-situ stress estimation needs to be considered for top seal failure.

- 1) Thorough geological knowledge of the basin and the prospect, such as type of reservoir, reservoir connectivity and thickness, single or stacked reservoirs, presence of faults, whether the faults are active, how deep-seated the faults are, whether the deep-seated reservoirs are connected to shallower ones, type of caprock, etc.
- 2) Maximum possible coverage of uncertainties associated with the T-Z model and hence with the velocity model.
- 3) Expectation of the geomechanical nature of the caprock-ductile or brittle.
- 4) Any signatures of breached reservoirs due to zero VES in seismic data, like gas expulsion features.
- 5) Velocity model showing any drastic reversal overlying the top of the structure.
- 6) Well Log and pressure data analysis in offset wells (if any) for overpressure-generating mechanisms.
- 7) The Mechanical Earth Model (MEM) requires robust calibration against field data for rock-property modelling and in-situ stress estimation, and to determine the ductility of the top seal (Figure 16).



Assessing trap integrity significantly affects prospect appraisal, safety, and drilling costs, making it a priority in exploration and operations. While trap integrity is most critical in exploration for deciphering accumulations, in drilling operations seal strength is a key safety factor, relevant to drilling margin, mud-weight planning, and borehole-stability management. Structures have higher retention capacity as depth increases below potential or actual leak points, improving prospectivity. Reservoir pore pressure at the top of the structure must be lower than that in the overlying shale for top seal integrity. Assessing hydrocarbon prospects by top seal is a sound prospect appraisal strategy, given the high costs of offshore drilling. The difference between pore and fracture pressure is a qualitative indicator of hydrocarbon retention capacity. Strong correlations between hydrocarbon discharge and pore-pressure dynamics will significantly influence exploration risk assessment in zones with elevated pressure.

The key terms are:

- 1) The breaching point is the depth at which the HC inflation line intersects the fracture pressure line. The breaching point must be shallower than the crest depth to retain hydrocarbons.
- 2) Retention capacity is the difference between fracture pressure and pore pressure (brine or HC-inflated) at the crest or sand top. The lower the value, the less likely

hydrocarbons are to be retained. In the Central North Sea, 900 psi (Gaarenstroom et al.¹⁵) or 750 psi (Swarbrick et al.¹⁶) is a risk threshold below which traps are considered breached.

- 3) The vertical distance between the crest and the breaching point indicates how close the crest is to the breaching point. This helps the geoscientist recognise the risk associated with depth uncertainty when interpreting the crest.
- 4) Maximum allowable headroom is the vertical distance between the spill depth and the breaching point. This indicates the maximum possible HC column that can be allowed during the volumetric evaluation.

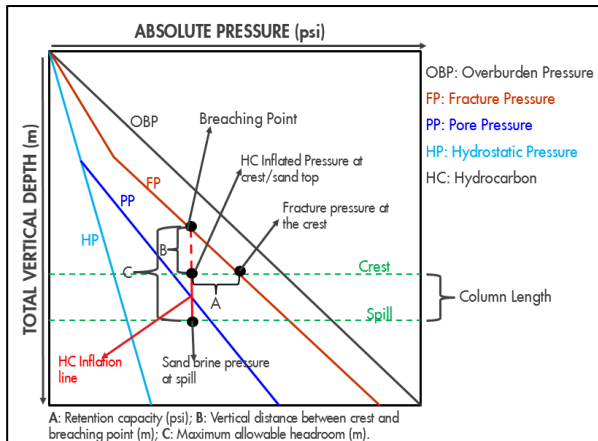


Figure 17: Headroom Potential Evaluation Terminologies

Following a comprehensive evaluation of geomechanical models across all conceivable scenarios, these models are instrumental in conducting headroom potential analyses of subsurface reservoirs. To facilitate rigorous headroom potential analyses, pore-pressure scenarios must be integrated with assessments of cap seal failure risk and potential associated fault slippage, alongside critical information on reservoir crest and spill depths. During the preliminary phases of exploration, the hydrocarbon column length- defined as the vertical distance between the crest and spill point- frequently remains undetermined or is only approximately established.

Gaarenstroom et al.¹⁵ found that in the central North Sea, most traps with retention capacities below 875 psi were non-productive or dry (Figure 18). A reservoir's retention capacity is defined as the difference between fracture and pore pressures at a specified depth. Figure 19 shows the pore and fracture pressure profiles of several wells in the onshore and offshore Netherlands, from which the prospects retention-capacity trend can be inferred¹⁷.

Seal Integrity Modelling makes an often-overlooked aspect of petroleum systems quantifiable and decision-driving for exploration and production.

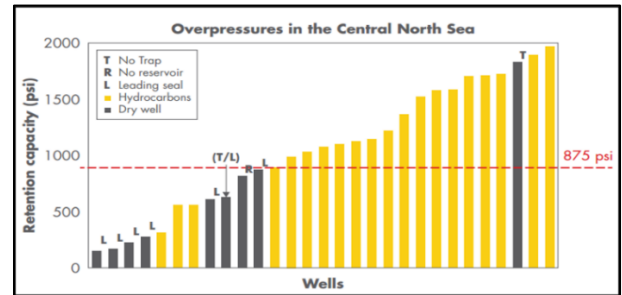


Figure 18: Retention capacity of several traps drilled in the central North Sea. Retention capacity is defined as the difference between the RFT pressure and the extrapolated LOT value at the shallowest reservoir level, based on the minimum horizontal stress trend¹⁵

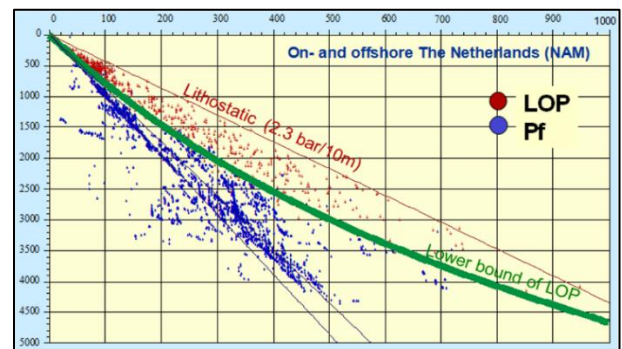


Figure 19: Pore and fracture pressure profile of Onshore and offshore Netherlands¹⁷

8. Case Demonstration from the Far East

This section presents workout of the headroom potential of an offshore exploration project study in Brunei, in the Far East. Brunei is situated within the Baram Delta Basin, a structural depression that has persisted from the early Miocene epoch to the present day, characterised by an accumulation of 35,000 to 45,000 feet of northward-prograding deltaic and associated non-deltaic clastic sedimentary wedges¹⁸. Brunei maintains an extensive Near Field Exploration (NFE) portfolio of undeveloped hydrocarbon resources in reservoir blocks along the northern flank. These blocks, beneath the shallow marine surf zone, have historically posed significant accessibility challenges due to the minimal water depth and the seaward-inclined structural configuration of the fault blocks. The green block shows the exploration venture and defined prospects with available structural details, following the defined workflow (Figure 20). Table 1 and Figures 21, 22, and 23 present the results. Prospects A, B, C, D, and F are protected, while E and G are breached traps.

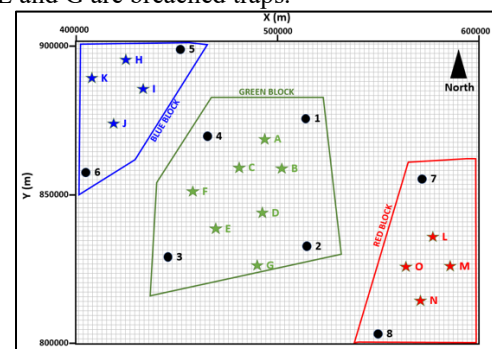


Figure 20: Prospect location map for Headroom Potential Evaluation demonstration

Table 1: Headroom Potential Analyses and Interpretation

AREA B BASIC INPUTS				HEADROOM POTENTIAL ANALYSES				
PROSPECT LOC	CREST (m)	SPILL(m)	BREACHING POINT(m)	MAXIMUM ALLOWABLE HEADROOM POTENTIAL	CREST TO SPILL - H/C COLUMN	VERTICAL DISTANCE BETWEEN BREACHING POINT AND CREST	RETENTION CAPACITY (psi)	BREACHING INTERPRETATION
A	3270	3370	3140	230	100	130	1200	Not Breached
B	3400	3600	3200	400	200	200	1050	Not Breached
C	3472	3625	3362	263	153	110	925	Not Breached
D	3375	3550	3300	250	175	75	850	Not Breached
E	3150	3332	3200	132	182	-50	500	Breached
F	3620	3726	3610	116	106	10	910	Not Breached
G	3410	3572	3475	97	162	-65	413	Breached

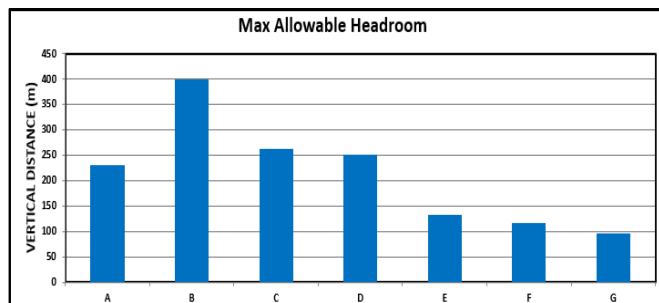


Figure 21: Maximum Headroom Potential Evaluation

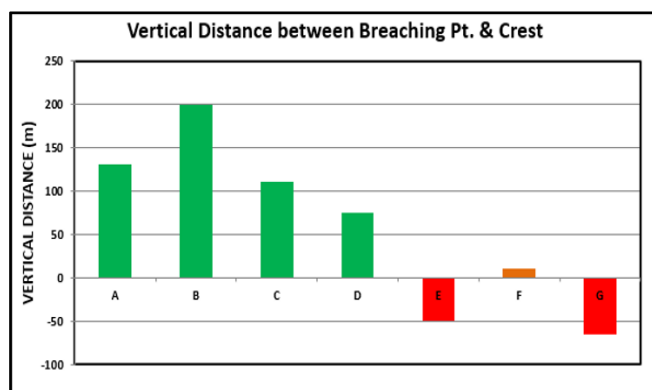


Figure 22: Vertical distance of the breach points for the structural crest of the prospects

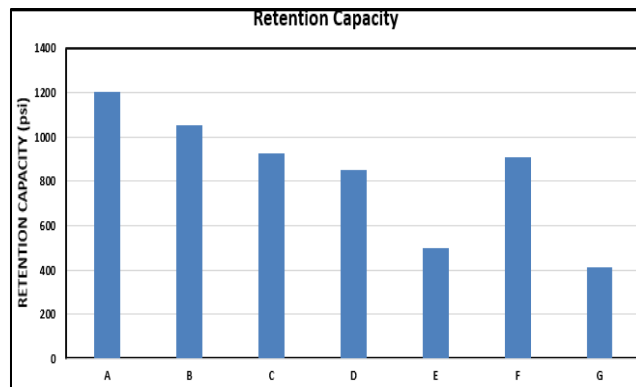


Figure 23: Retention Capacity for the crest of the prospects

9. Risk Register for Headroom Potential Evaluation

A risk register for risking the top seal integrity of a prospect is designed considering the elements discussed in the headroom potential analysis. It is presented as Table 2.

Table 3: Risk Register for Headroom Potential Evaluation

		Risk Register (Interpreter to fill-in colors)			Interpreter Comments	Reviewer Comments
		High risk	unknown or medium	low risk		
Risk of Top Seal Failure	Trap crest is close to the mudline or ground surface					
	AOI is known to be hydrostatically (normally) pressured, or have medium or high overpressures					
	Nearby traps are known (or believed) to be top seal limited					
	Trap is high relief or proposed column height is large					
	Top seal is silty					
	Trap crest is structurally highest point in basin, indicating high risk of top seal limitation					
	Trap crest is structurally deeper than basin apex, indicating its potentially a pressure-protected trap					
	What is overpressure in offset wells?					
	What are mudweights in offset wells (converted to pressures at objective level)?					
	What are overpressures from seismic velocities?					
	Seismic velocity inversions are known in AOI					
	Seismic wipeouts are present over trap crest, indicating blown or leaking trap					
	Expulsion features, pockmarks, mudvolcanoes, slumps, chemosynthetic communities, seeps are present at seafloor, indicating a blown or leaking trap					
	Calculated effective stress at trap crest is high, medium or low.					
	Top seal is assumed to be thin salt or a weld					
	Top seal is laterally variable in facies, acoustic impedance or velocity					

A worked-out example of the risk register for two offshore prospects is given in Table 3.

Table 3: Example of a Headroom Potential Risk Register

		Risk Register (Interpreter to fill-in colors)			Interpreter Comments	Reviewer Comments
		High risk	unknown or medium	low risk		
	Trap crest is close to the mudline or ground surface	< 5000 ft below mudline = High risk		> 5000 ft below mudline = low risk		
Risk of Top Seal Failure	AOI is known to be hydrostatically (normally) pressured, or have medium or high overpressures	High OP		Hydrostatic		
	Nearby traps are known (or believed) to be top seal limited	Yes		No		
	Trap is high relief or proposed column height is large	Yes		No		
	Top seal is silty	Yes		No		
	Trap crest is structurally highest point in basin, indicating high risk of top seal limitation	Yes		No		
	Trap crest is structurally deeper than basin apex, indicating its potentially a pressure-protected trap	No		Yes		
	What is overpressure in offset wells?	High OP		Low or no OP		
	What are mudweights in offset wells (converted to pressures at objective level)?	High MW		Low MW		
	What are overpressures from seismic velocities?	High OP		Low or no OP		
	Seismic velocity inversions are known in AOI	Yes		No		
	Seismic wipeouts are present over trap crest, indicating blown or leaking trap	Yes		No		
	Expulsion features, pockmarks, mudvolcanoes, slumps, chemosynthetic communities, seeps are present at seafloor, indicating a blown or leaking trap	Yes		No		
	Calculated effective stress at trap crest is high, medium or low.	Low (few hundreds of psi)		High (thousands of psi)		
	Top seal is assumed to be thin salt or a weld	Discontinuous weld		Continuous autochthonous		
	Top seal is laterally variable in facies, acoustic impedance or velocity	Yes		No		

10. Conclusions

Hydrocarbons can be retained in zones of elevated overpressure if a secure trap is present, sealed by caprock with sufficient mechanical integrity. A thorough understanding of the geological framework is essential because it defines the subsurface pore and fracture architecture and helps predict a trap's sealing and retention capabilities. A seal, or caprock, is a low-permeability layer that prevents hydrocarbons from escaping the trap. Its effectiveness determines whether hydrocarbons accumulate or leak away. In short, the seal acts as the gatekeeper of hydrocarbon retention.

A strong seal maintains pressure differences across the reservoir, keeping hydrocarbons in place until production begins. In contrast, a weak or breached seal can cause partial or complete hydrocarbon loss, resulting in dry wells or smaller-than-expected accumulations. Evaluating headroom potential is integral to Seal Integrity Modelling and plays a crucial role at multiple stages of petroleum exploration and development, helping to derisk prospects. Seal Integrity Modelling turns an often-overlooked aspect of petroleum systems into a quantifiable, decision-driving part of exploration and production.

As onshore exploration targets move deeper onshore and deepwater targets become more complex, understanding seal behaviour is no longer optional- it is fundamental. Ultimately, a reservoir is only as good as its seal. This paper presents a systematic workflow for evaluating trap headroom capacity and, through a Far East case study, illustrates how it enhances petroleum hydrocarbon exploration.

Nomenclature

Boe = barrels of oil equivalent

PP = pore pressure

FP = fracture pressure

VES = vertical effective stress

Pc = capillary entry pressure

MFS = maximum flooding surface

RSP = reservoir seal pair

OCR = over- consolidation ratio

UCS = uniaxial compressive strength

UCS_{nc} = UCS of normally pressured mudrocks

BRI = mudrock brittleness index

NES = normal effective stress

S = specific surface area

DCM = dielectric constant measurements

GR = gamma ray

MEM = mechanical earth model

OBP = overburden pressure

HP = hydrostatic pressure

HC = hydrocarbons

LOP = leak-off pressure

Pf = formation pressure

RFT = Repeat formation test

LOT = Leak-off test

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Author Profile



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