



Lessons Learned from the Golden Zone Concept for Understanding Overpressure Development, and Drilling Safety in Energy Exploration

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1 Introduction

At the invitation of Prof. Robert Bea, of the Deepwater Horizon Study Group (DHS Group), the following technical summary of the "Golden Zone" concept (Buller et al, 2005; Nadeau, 2011), its applications in the US Gulf of Mexico basin, implications for drilling safety, and lessons learned particularly over the last 6 months, has been prepared. It is hoped that this Working Paper with further advance the "Golden Zone" concept within the petroleum industry, as well as regulatory agencies, with respect to sub-surface energy exploration risk assessment and management.

2 An Overview of the Golden Zone Concept

Over the last 20 years mineralogical models for sedimentary diagenesis have been developed for predicting the impact of clay mineral diagenesis and quartz cementation on porosity/permeability evolution in sedimentary basins (Björkum et al., 1998a,b; Björkum and Nadeau, 1998; Buller et al., 2005; Nadeau, 1999, 2011; Nadeau et al., 1985; 2002; 2005; Nadeau and Bain, 1986; Oelkers et al., 1998; Schneider et al., 2003; Walderhaug, 1994, 1996). These models indicate that the precipitation of diagenetic clay minerals at temperatures $>60^{\circ}\text{C}$ leads to very low permeability in shales/mudstones, creating an important component in the geological controls on the distribution of oil and gas reserves in sedimentary basins. After extensive analyses measuring the amounts of quartz cement in North Sea sandstone reservoirs as a function of the burial history, quartz surface area, and stylolite frequency, the kinetics as well as the material mass balance of this precipitation-rate controlled reaction were also established (Walderhaug, 1994, 1996; Aase et al., 1996; Björkum et al., 1998b; Oelkers et al., 1996, 1998, 2000; Walderhaug et al., 2000, 2004). This research was mainly targeted at reservoir quality, porosity, and permeability, prediction. The implications for overpressure development, seal failure, hydrocarbon migration, and overall exploration risks ultimately came to supersede these initial research goals. This was evidenced by numerous exploration wells finding only residual hydrocarbon columns from former large oil and gas accumulations in good quality reservoirs whose seals had failed due to fluid overpressure at depths of $\sim 4\text{km}$ and temperatures $>120^{\circ}\text{C}$. It was soon realized that the exponential increase in cementational porosity loss rates was a major contributor to reservoir overpressure development and seal failure of low permeability shales.

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The quartz precipitation rate increases exponentially as a function of temperature and, unlike mechanical compaction, porosity loss by this process is not arrested by overpressure and reductions in effective stress (Bjorkum, 1996). Once overpressure is established in isolated pressure compartments, it will increase beyond the formation breakdown point, and reservoir fluids including oil and gas will migrate vertically via hydro-fracturing (Hubbert and Willis, 1957; Lothe et al., 2005) through anisotropic low permeability lithologies, to shallower reservoir entrapment intervals. This last point is extremely important, as will be shown later with regard to overpressure drilling and safety risks.

As a result, the probability of overpressure in fault segmented basins increases dramatically with increasing depth and temperature. In the North Sea this critical temperature of 120°C is reached at approximately 4 km depth (Figure 1). Around this depth, reservoirs typically show a rapid departure from more hydrostatic pressure condition, to very high degrees of overpressure, often approaching lithostatic gradients, and near the leak off pressure limit of the formations.

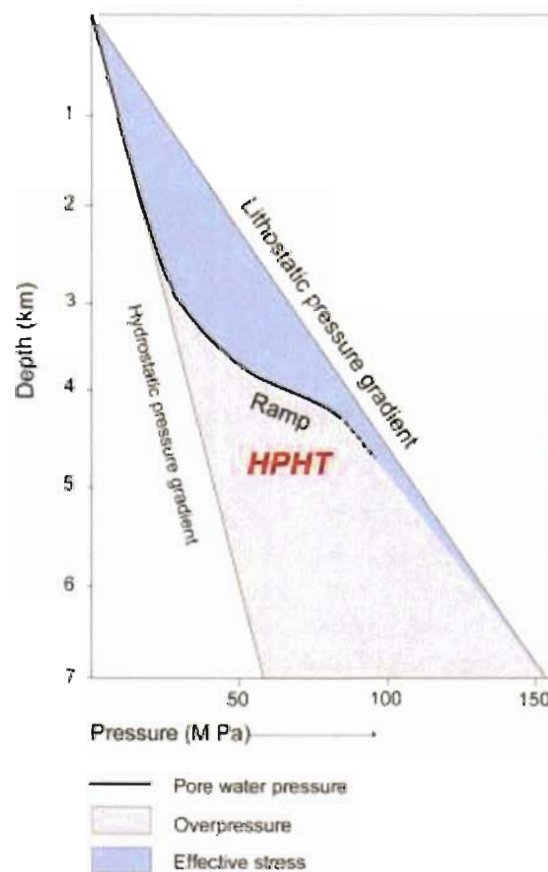


Figure 1 – Generalized depth plot of subsurface pressure regimes on the Norwegian continental shelf.²

² Note that the overpressure pore pressure ramp marks the departure of pore fluid pressure from hydrostatic gradients to lithostatic gradients, with a rapid reduction in the overburden effective stress. This transition ramp marks the onset of high-pressure high-temperature (HPHT) conditions (after Buller et al., 2005 and Nadeau, 2011).

These reservoirs are often referred to as HPHT, or high-pressure high-temperature reservoirs. For the purposes of this paper we will define HPHT subsurface environments as those >1.4 times hydrostatic pressure gradients (>1.4 g/cm³ specific gravity (SG) equivalent gradients or $\sim >12$ pounds per gallon (ppg) drilling mud weights), and $>120^{\circ}\text{C}$. These values are based on the analysis of reservoir pressure and temperature probability statistics from the Gulf of Mexico (Ehrenberg et al., 2008), as will be discussed later (Figure 5). The petroleum industry typically uses the higher values of 149°C (300°F) and ~ 15 ppg or 1.7 g/cm³ SG pressure gradients, to define HPHT drilling environments.

From the perspective of the Golden Zone (GZ) concept, the distribution of hydrocarbons in sedimentary basins is the result of dynamic migration from mature source rock maturation areas, as well as remigration of hydrocarbons from overpressured reservoirs. These HPHT structures have completely or partially failed, remigrating most of their oil and gas to the optimal accumulation zone, which we call the GZ (Figure 2).

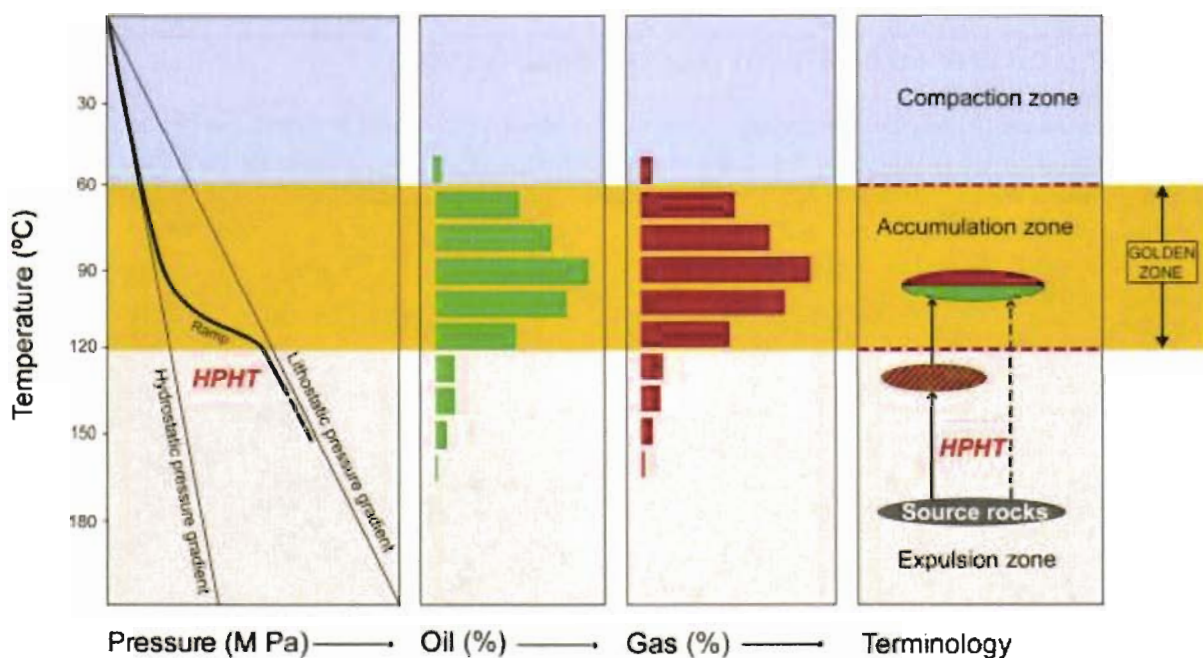


Figure 2 – A composite thermal zonation model for sedimentary basins.³

Based on this understanding, Buller et al. (2005) and Nadeau (2011) have identified the following thermal zones in sedimentary basins:

- the compaction zone $<60^{\circ}\text{C}$,
- the accumulation zone from 60°C and 120°C also known as the “Golden Zone,”
- the expulsion zone from 120°C and 200°C , and
- the depleted zone $>200^{\circ}\text{C}$.

³ The compaction zone $<60^{\circ}\text{C}$; the optimum petroleum accumulation zone 60°C to 120°C also known as the Golden Zone; the high-pressure high-temperature (HPHT) fluid expulsion zone 120°C to 200°C ; and the depleted zone $>200^{\circ}\text{C}$ (after Buller et al., 2005 and Nadeau, 2011).

The thermal structure of the Earth's sedimentary basins has also been examined in order to map the GZ worldwide (Nadeau and Steen, 2007; Steen and Nadeau, 2007). This effort has focused on using high quality reservoir temperature data, rather than the more numerous but less certain bottom hole temperature data (BHT data, e.g., Hermanrud et al., 1990; for a US Gulf Coast comparison, cf. Nagihara and Smith, 2008, their Figure 2 with Ehrenberg et al., 2008, their Figure 2) as a basis for predicting the reservoir temperatures of exploration targets. This is very important, because the thermal gradients in sedimentary basins can vary widely, but generally fall between $30^{\circ} \pm 10^{\circ}\text{C}/\text{km}$, which in turn mean that the thermo-chemical overpressure "ramps" can occur at significantly different depths.

It is important to acknowledge that the GZ view for overpressure development is not shared by most basin modelers. The commonly held view by analysts, as implemented in these numerical simulators, is that mechanical compaction disequilibrium is dominantly responsible for overpressure generation (e.g., Bethke *et al.*, 1988; Giles *et al.*, 1998), in combination with low permeability shale aquitards which are crucial components of overpressure (Bjørlykke *et al.*, 2010).

3 The Golden Zone in the US Gulf of Mexico

A concerted effort is being made to compile reservoir data world wide to further evaluate the GZ concept. The US Gulf Coast is a focus area for this effort, in part because it is characterized by extremely high rates of sedimentation and burial, having predominantly very young Neogene Tertiary reservoirs (Figure 3).

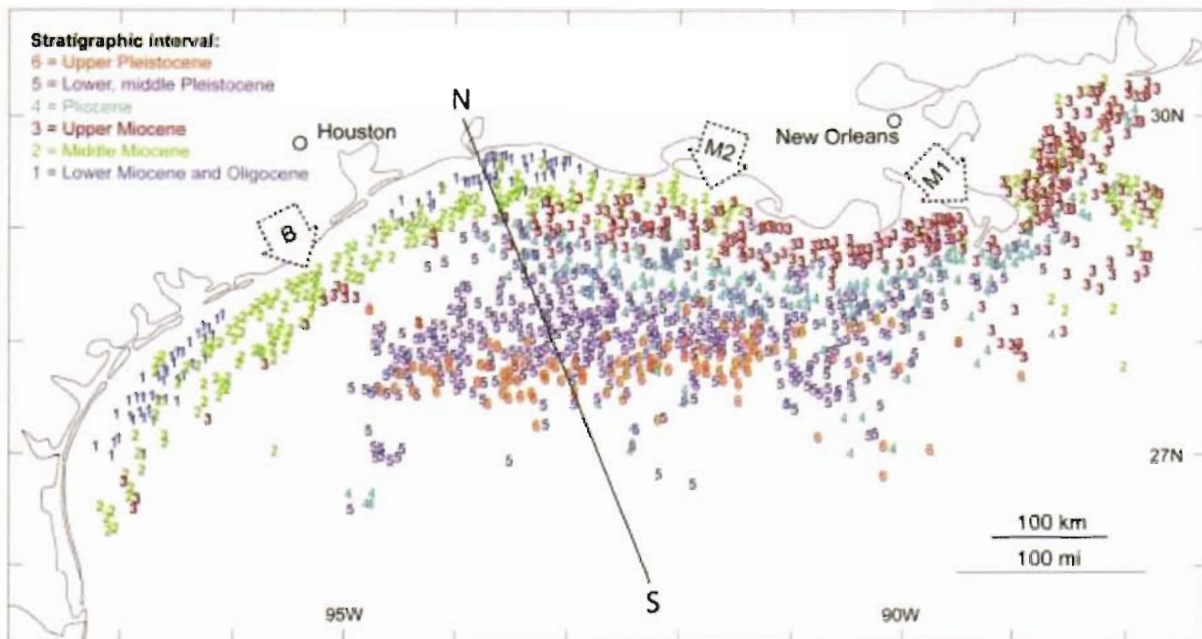


Figure 3 – Map showing the geological ages and spatial distribution of US Gulf Coast reservoirs.⁴

⁴ The pattern represents the reservoir ages which are predominantly within the Golden Zone across the basin, which is controlled mainly by the geothermal gradients and the sedimentary burial from the Mississippi River system arrows "M1" present day and ~Miocene time and "M2" mainly in Pleistocene time, and to a lesser extend the Brazos River system arrow "B" along the Texas coast. The Golden Zone model is unique in

It also has the largest and most comprehensive publicly available offshore reservoir data base in the world (Ehrenberg et al., 2008), and as such is unaffected by uplift and erosion, except for a few isolated occurrences such as certain reservoirs in the Perdido foldbelt. It was thought that in a basin so dominated by rapid burial and mechanical compaction, thermal chemical process would be only of minor importance. It was unexpected, therefore, to observe that ~90% of the oil and 80% of the gas reservoirs occur within the GZ (Nadeau et al., 2005), despite the relative exploration maturity of the shallow water shelf areas at that time.

The distinctive pattern of reservoir ages in Figure 3 reflects this distribution, and the GZ concept is thus far the only oil and gas migration and accumulation model that can predict it. The US Gulf Coast, therefore, provides a rigorous validation of the GZ concept as well as its founding geological diagenetic process models. The reservoir age pattern reflects an overall decrease in age of offshore reservoirs, mainly from Miocene, to Pleistocene in the outer shelf, and then back to Miocene and older reservoir plays in deep water environments. This distribution is in response to:

- a) generally decreasing geothermal gradients in deep water environments,
- b) sediment input variations through time, mainly from the Mississippi River and to a lesser extent the Brazos River systems (Figure 3), and
- c) variable surface temperatures related to water depth (e.g., Figure 9b).

The GZ concept predicts that HPHT environments should dominate deeper than the 120°C isotherm (Figure 4). This can be compared with basin simulations based on mechanical compaction

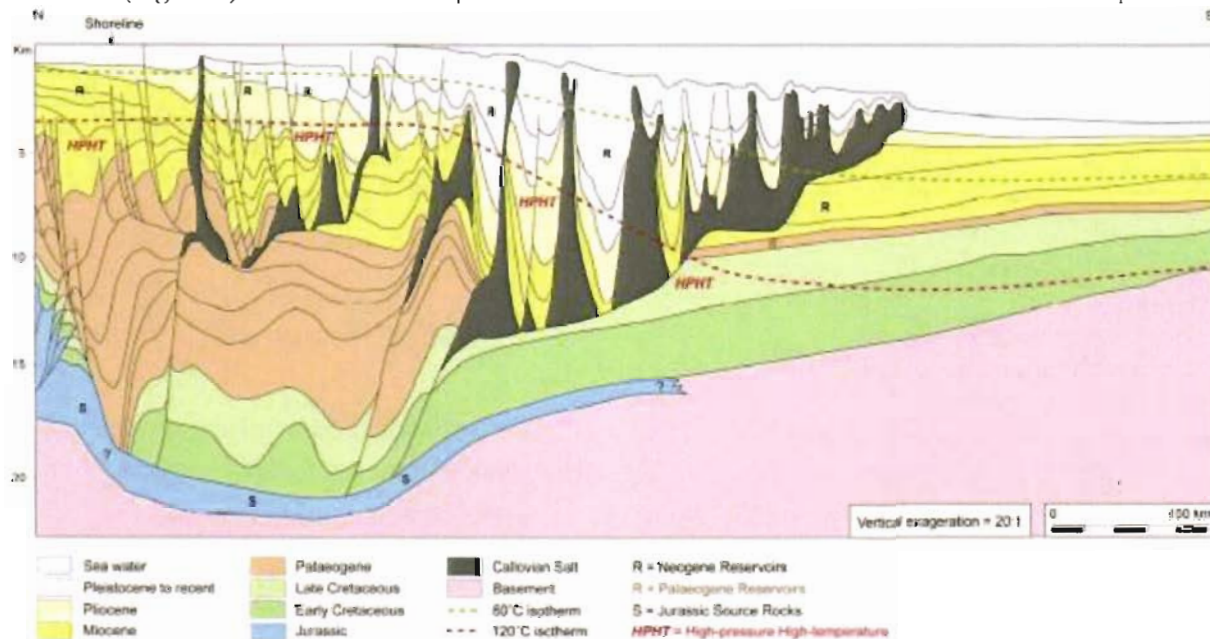


Figure 4 – Geological cross section of the US Gulf Coast.³

its ability to explain this pattern of discovered reservoirs. The line N-S shows the approximate location of the geological cross section in Figure 4 (after Ehrenberg et al., 2008 and Nadeau, 2011).

³ Shows the complex relationships of stratigraphy and salt movement tectonics resulting from the very rapid sediment burial rates in this basin (modified after Peel et al., 1995 and Nadeau, 2011). The general locations of the 60°C and 120°C isotherms of the Golden Zone are also shown (Steen, personal

disequilibrium, which predict high-pressure environments in areas of rapid Pliocene-Pleistocene sedimentation loading rates (e.g., Summa et al., 1993, their Figure 8). Despite the high sedimentation rates, allochthonous salt tectonics, and dynamic fluid migration, the thermal structure of the basin is generally well behaved with respect to reservoir temperature, play segment burial depth, and water depth (e.g., Figure 9a). It is important to remark here that although there is a general trend of decreasing geothermal gradients in deeper water environments, there are notable deep water thermal anomalies, of ~50% (Steen personal communication) that should also be considered when making geological evaluations for exploration potential, overpressure predictions and drilling safety.

In order to evaluate the GZ concept vs. mechanical compaction models for overpressure, the relationship of reservoir pressures vs. temperature and burial sedimentation rates were examined and compared (Figure 5a). Here it is important to recall that reservoir overpressure also requires restricted lateral drainage, meaning that the reservoirs have to be laterally sealed, as well as top sealed by low permeability shales. This is normally accomplished by the presence of fault bounded pressure compartments in sedimentary basins (Nadeau et al., 2005). Even with this important proviso, the Gulf Coast data show that the median (P50 Figure 5a) reservoir pressure probability is for normal, or near hydrostatic pressures to occur at temperatures <60°C, despite the extreme rates of porosity loss in this compaction zone. At >60°C the probability of overpressure begins to increase, at first gradually and then more rapidly, such that at temperatures >120°C, the P50 is increasing exponentially, with 50% of the reservoirs having pressures >1.4 times that of hydrostatic gradients. We use this gradient, therefore, to distinguish between normal and high-pressure environments.

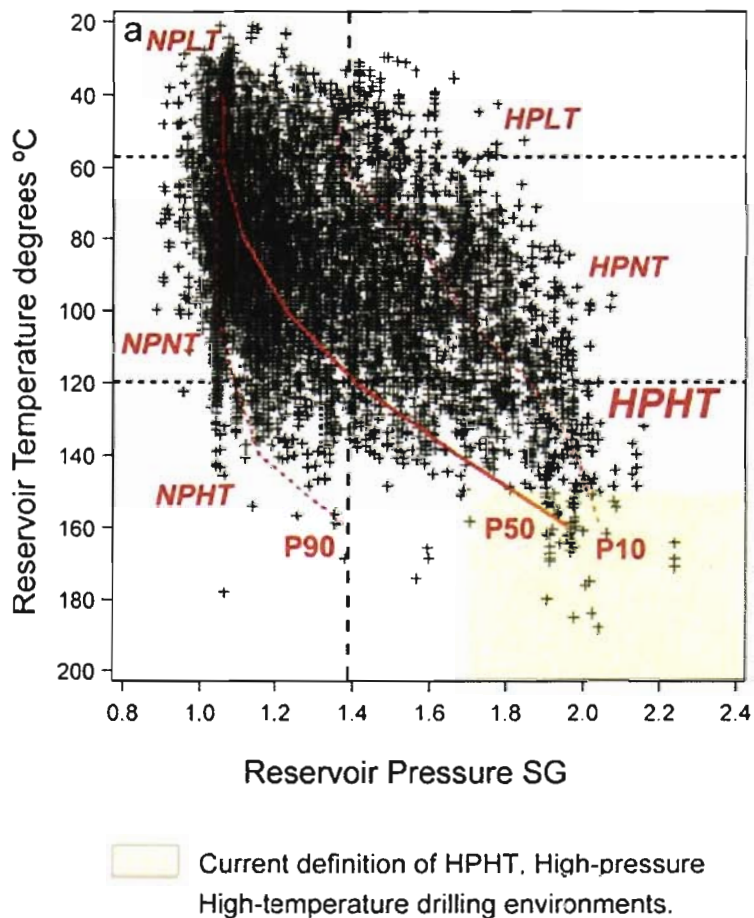


Figure 5a – Reservoir temperature versus pressure.

communication), and demonstrate how the dominant reservoir play ages in Figure 3 occur within the predicted optimal accumulation zone temperature interval. Note how the Golden Zone deepens and thickens to the South, in response to lower geothermal gradients and surface temperatures (see also Ehrenberg et al., 2008), such that older reservoirs re-enter the Golden Zone in deep water environments (see text).

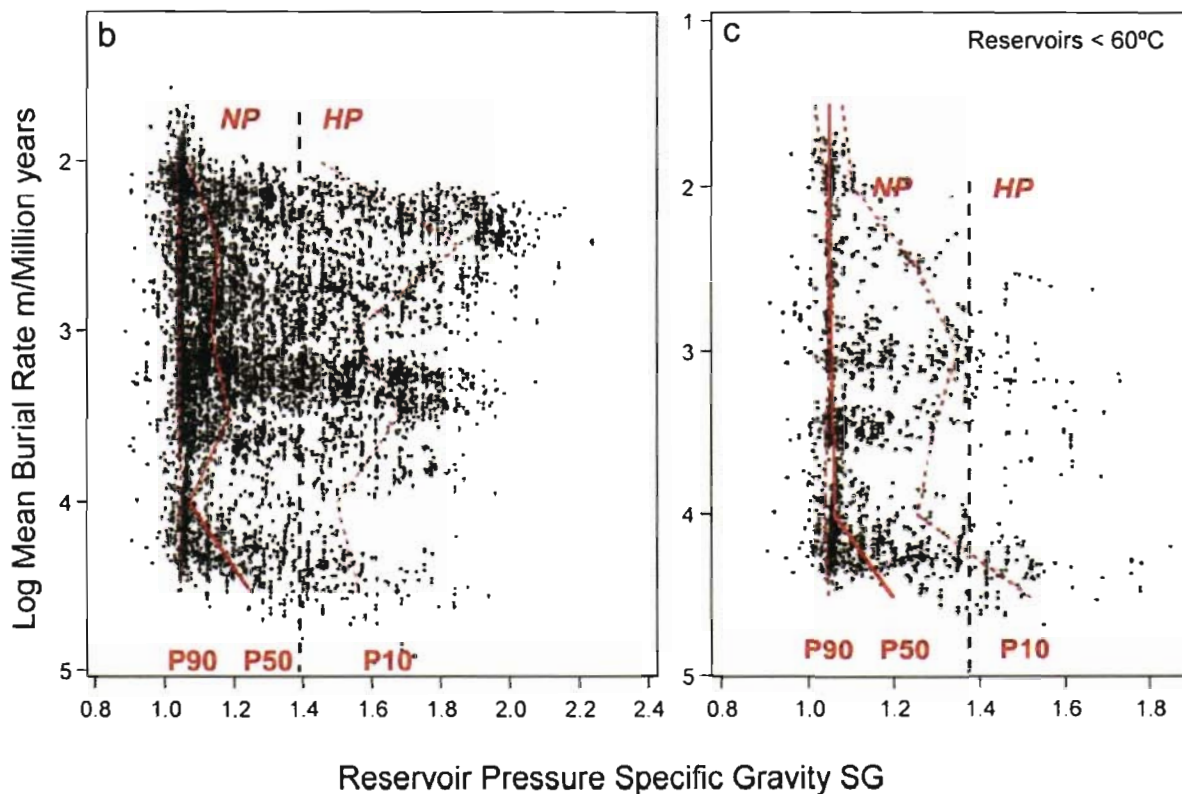


Figure 5b and 5c – Log mean burial rate versus reservoir pressure specific gravity.⁶

Those who are unfamiliar with temperature vs. pressure analysis of very large data sets should note that most of these reservoir observations are normally pressured, in spite of the extremely high rates of burial and sedimentation. That is why the calculated probability distributions are also included in Figure 5a and Figure 5b. In fact, 79% or ~4 out of 5 GZ reservoirs are NPNT (Normal-Pressure Normal-Temperature, Table 1), as compared to 64% HPHT or ~2 out of 3 reservoirs in the expulsion zone (Table 1). This means that the risk of high-pressure reservoirs increases by a factor of 3, or 300%, at temperatures >120°C.

When reservoir pressure vs. the mean sedimentation burial rates is examined (Figure 5b), we find that there is little if any relationship with the pressure probability distributions. The burial rate scale is inverse logarithmic in order to compare with the reservoir temperature (Figure 5b and 5c). These are among the highest burial rates in the world, up to ~10,000 meters per million years (Log scale 4

⁶ US Gulf Coast reservoir data (n=11864) showing the distribution and probability statistics for temperature vs. pressure in specific gravity (SG) units (a) and burials rates (b & c). Note that the median P50 probability increases exponentially at temperatures >60°C, such that at >120°C the P50 >1.4 SG, entering the HPHT expulsion zone. Temperature vs. pressure is utilized rather than depth because thermal gradients in this basin vary widely, between 14°C and 36°C per kilometer (Ehrenberg et al., 2008). Note also the inverse logarithmic scale on the burial rate vs. pressure. The overpressure probability statistics show little to no relation to this indicator of mechanical compaction rates, with the exception of the P10 probability for reservoirs in the <60°C zone (c) at burial rates >100 meters per million years (log scale >2, see text). The current industry definition of HPHT drilling environments is shown on (a) for comparison, in the yellow shaded area. Less than 1% of the discovered reservoirs fall into this current definition.



to 5). By comparison, North Sea burial rates are orders of magnitude lower, generally 10 to 100 meters per million years (Log scale 1 to 2). The older, mainly Miocene reservoirs at the top of Figure 4b have, if anything, a higher probability of overpressure compared to the extremely young and rapidly buried Pleistocene reservoirs at the bottom. In fact the data show general repeating trends where the burial rate of any given reservoir age class required to reach the 120°C isotherm is where high-pressure is predominantly observed. Older reservoirs generally reach this isotherm at lower burial rates than do the younger reservoirs, as can be observed in the P10 probability distribution (Figure 5b). Thus the P10 actually shows an overall decrease in pressure with increasing burial rates.

Table 1 – Distribution of reservoir overpressure – U.S. Gulf Coast.⁷

Reservoir Temperature	Normal Pressure	Overpressure SG > 1.4
<60°C Compaction Zone	95% NPLT	5% HPLT
50° to 120°C Golden Zone	70% NPNT	21% HPNT
>120°C Expulsion Zone	36% NPHT	64% HPHT

Closer examination of Figure 5a shows that in the compaction zone at <60°C there are a few HPLT (High-Pressure Low-Temperature) reservoirs. The P5 probability is 1.4 SG, that is to say that 5% of the pressure observations are >1.4 times the hydrostatic pressure gradient (Table 1). There is a tendency for these observation to originate from reservoirs with burial rates >100 meters per million years (log value >2, Figure 5c) so here mechanical compaction disequilibrium is the most likely overpressure mechanism. This is not surprising, given the very large porosity reductions in this mechanical compaction zone, from ~40% to 25% porosity for sandstones and ~>50% to <20% for shales (Giles et al., 1998). These shallow reservoirs predominantly contain dry gas, formed from bacterial activity and referred to as biogenic gas, or exsolution gas from rising formation waters entering lower pressure regimes (Nadeau et al., 2005). The pressure data also demonstrate that some of these reservoirs have restricted lateral drainage, even at relatively shallow levels of burial. Nearly 95% of these reservoirs have normal or moderate overpressure, which indicates that shale permeabilities in this zone are relatively high, in the micro-Darcy range, or sufficient to facilitate the escape of compaction driven formation water under mainly hydrostatic pressure conditions.

4 Implications for Drilling Safety and Environmental Risks

The predictive power of the GZ concept is unique with respect to its ability to quantify exploration risk assessment, particularly for overpressure, as well as for drilling and environmental safety. Safety statistics compiled by the Norwegian Petroleum Directorate over the years 1995-2005

⁷ Distribution of discovered oil and gas reservoir overpressure in the US Gulf Coast within the defined temperature zones from 11864 reservoirs (Figure 4a, see also Ehrenberg et al., 2008), using the pressure gradient of 1.4 SG, or 1.4 times the hydrostatic gradient, as the boundary between normal and overpressured reservoirs (see text). Note that 79%, or nearly 4 out of 5, Golden Zone (60°C to 120°C) reservoirs are normally pressured, and that 64% of the expulsion zone reservoirs >120°C, or nearly 2 out of 3, are overpressured. The data demonstrate that the overall risk of reservoir overpressure is 3 times (300%) greater at temperatures >120°C than for Golden Zone reservoirs. (NP = normal-pressure <1.4 SG; HP = high-pressure >1.4 SG; LT = low-temperature <60°C; NT = normal-temperature 60°C to 120°C; HT = high-temperature >120°C; thus HPHT = high-pressure high-temperature, etc., see text).



show that the serious incident frequency for HPHT wells, as defined by the petroleum industry, were ~10 times that of normally pressured wells (Petroleum Safety Authority, 2006). Since that time, safety performance has improved significantly. Furthermore, HPHT wells typically cost between 2 and 10 times more than conventional NPNT wells. Therefore, understanding the geological processes responsible for the occurrence of HPHT reservoirs is vital in order to properly assess these risks as well as increase exploration efficiency.

A key aspect of the GZ concept deals with the behaviour of overpressured systems in the sub-surface. Mechanical compaction disequilibrium models typically assume that once overpressure is established, further porosity loss can only be facilitated by diffusive fluid migration through the sealing lithologies (e.g., Waples and Couples, 1998). This is due to the negative feedback caused by the inverse relationship between overpressure and effective stress (Figure 1) which drives mechanical compaction. Sediment "undercompaction" at shallow levels of burial is commonly attributed to this behaviour. In contrast, the GZ concept has no such negative feedback. The porosity loss is controlled by, and an exponential function of, temperature. Once overpressure is established, it can increase through the fracture initiation (leak-off) and formation break-down points, to the fracture propagation pressure, so as to hydraulically fracture non-isotropic sealing lithologies (e.g., Hubbert and Willis, 1957; Bjørkum and Nadeau, 1998; Hermanrud et al., 2005). The resulting dynamic expulsion of fluids, including oil and gas, is the driving force which creates and maintains the GZ as a steady state distribution with respect to temperature. Therefore, the GZ concept also predicts that there are low probabilities, but finite drilling risks, particularly in HPHT environments, for encountering such fracture zones which can render normal drilling, as well as certain well completion operations, extremely problematic in the worse case scenarios. Although the likelihood of encountering such fracture zones in the sub-surface are low, operators need to be aware of their existence, with effective criteria to recognize them, and procedures to manage them under a variety of drilling conditions.

It is recommended, therefore, that burial and thermal modeling of these processes in addition to rock stress modeling be included in basin evaluation methods to help predict and map geological exploration risks, including those related to the:

- a) occurrences of fluid overpressure,
- b) development of procedures for recognizing and mitigating operational safety, and related environmental risks, and
- c) develop methods to better quantify the degree of overpressure in formations with high temperature diagenetic mechanisms which are dominantly responsible for creating and maintaining overpressured drilling conditions.

5 Some Lessons Learned

Over the last 6 months, numerous and lengthy discussions have been held on drilling safety, particularly in the deepwater GoM. Insights from the GZ concept have proven valuable to understanding the sub-surface conditions which can lead to serious safety incidents, well control, and challenging well completion operations.

An examination of global Leak Off Pressures (LOP)/minimum stress measurements and those in the US GoM shows the presence of a significant number anomalously low leak off pressure observations, particularly for offshore Louisiana (Figure 6).⁸ These observations suggest that there are sub-surface low stress regimes in the GoM, possibly due to local tension/dilation related to upper marine slope environments and/or salt tectonics. In combination with GZ geological processes, these low stress regimes could pose significant risks to drilling and well completion operations.

The GZ concept indicates that under geological conditions of confined lateral drainage, the probability of reservoir pore pressures which exceeds the minimum rock stress increases exponentially as a function of temperature. The pressures can increase through the Formation Break-down Pressure (FBP) and the Fracture Propagation Pressure (FPP) established by the minimum stress in anisotropic sealing shale/mudstone lithologies (Figure 7).⁹ In areas with high minimum rock stress, this may not pose serious challenges to deepwater drilling operations, because the formation integrity is maintained by high confining stress, as suggested by the global trend of the high leak off pressure tests (Figure 6). However, in sub-surface conditions with low minimum rock stress, the maximum pore pressure required to fracture anisotropic top seals may be anomalously low, only say 1.5 g/cm³ pressure gradients. Given this relatively low value, petroleum geoscientist and engineers may be inclined to consider such a pressure gradient more or less routine, not properly considering this value in relation to the sub-surface stress regimes. The offshore Louisiana data indicate that the anomalously low LOP/stress data, i.e., data below the global trend on Figure 6, is more common in the Mississippi Canyon area, Figure 8, which may be in close proximity to relatively steep marine slump/erosion scarps or potential slope failure surfaces.¹⁰ In the data set

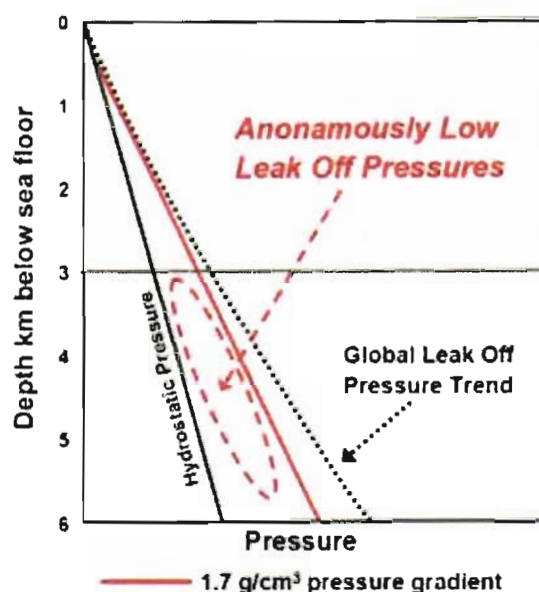


Figure 6 – Global leak off pressure trend.⁸

⁸ Global Leak Off Pressure (LOP) pressure trend and that of anomalously low observation from offshore Louisiana, deeper than 3km below sea floor. Values with less than 1.7 g/cm³ equivalent mud weight gradients are a particular concern for drilling operations.

⁹ A Leak Off Pressure (LOP) test vs. time plot for mud pressure in a well borehole. The test is performed by pumping drilling mud at a constant rate into the borehole. Normally the test is only performed until the mud starts to leak into the formation (LOP). The Formation Break-down Pressure (FBP) is typically ~10% greater than the LOP. After the formation has broken down, a hydraulic fracture is propagated at the Fracture Propagation Pressure (FPP). Note that the LOP and FPP can have similar pressure values.

¹⁰ The Mississippi Canyon formed about 17000 years BP (Before Present (1950), Behrens, 1985), during the Latest Pleistocene low stand, when sea level was more that 100 meters lower than it is today. The massive slump (1500 to 2000 km³, Hardin, 1987) probably resulted in reduced confining stresses in sub-surface formations, which could bring nearby HPNT accumulations to failure. Much of the modern-day natural oil and gas seepage in the area (Geyer et al., 1972), estimated at 1000 barrels of oil (Mitchell et al., 2000) and several million cubic feet of gas (at STP) per day could be a consequence of this event. Such seepage rates are unlikely to be sustainable over geological periods of time (~millions of years). Other marine areas affected by recent slumping include the Mid-Norwegian Continental Shelf, by the ~3000 km³ Storegga slide about 8000 years BP (Yang et al., 2007; Færseth and Sætersmoen, 2008).

investigated, 75% of anonymously low LOP $< 1.7 \text{ g/cm}^3$, greater than 3km depth below sea floor, occur in this area.

A well which encounters a fracture with low confining rock stress and relatively high fluid pressures could experience severe well control problems in the form of:

- severe Loss Circulation (LC) fluid volumes,
- excessive requirements of Loss Circulation Materials (LCM) to maintain well control, and
- major flow back of fluids and gas kicks when the mud weight is reduced in attempts to reduce lost circulation volumes.

The risks can be compounded if the operator fails to realize that "LOP" test results could in fact be FPPs (Fracture Propagation Pressures, normally close to the minimum stress), and that there may be no FBP (Formation Break-down Pressure) integrity drilling safety margin in the well.

Additional problems could also be encountered during well completion/casing operations, particularly for cementing operations. During cement displacement, the formation may not have sufficient integrity and strength to allow proper cement distribution and bonding. Significant cement volumes could be lost into the fracture system in the casing shoe area, and not distributed effectively to form an adequate pressure barrier to reservoir or fracture fluid flow.

Given the above understanding, methods and procedures should be developed to:

- map the sub-surface geological conditions which give rise to anomalously low minimum rock stress conditions, relatively high fluid pressures, and establish depth vs. rock stress relationships;
- design wells and operating procedures to effectively manage these pore pressure drilling conditions; and
- establish criteria for recognizing sub-surface conditions, including fluid leakage zones, which can not be safely drilled or well intervals completed.

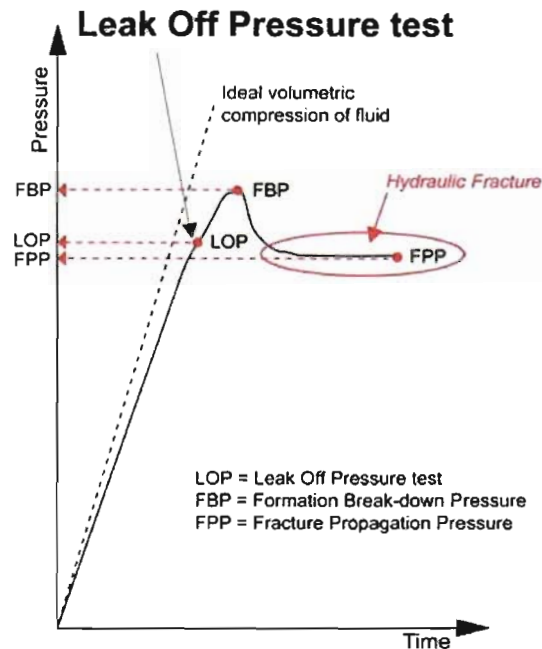


Figure 7 – Leak off pressure test.⁹

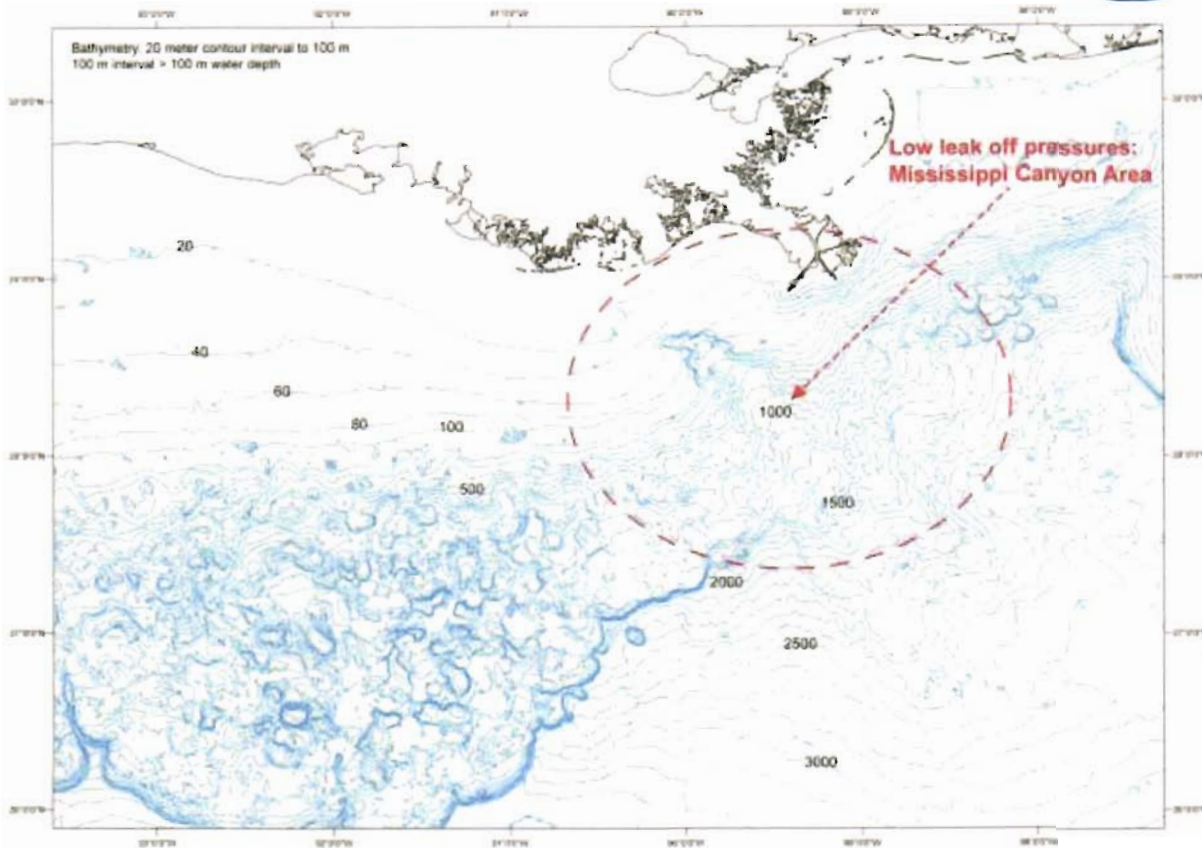


Figure 8 - An offshore Louisiana map, showing a potential area of anomalously low LOP data.¹¹

The Golden Zone Concept provides a methodology to predict reservoir pressures based on temperature, using the probability distributions shown on Figure 5. This requires the use of:

- existing reservoir depth and temperature measurements (e.g., Figure 9a) to estimate geothermal gradients,
- sea floor surface temperatures, which can often be estimated as a function of water depth (e.g., Figure 9b), and
- interpolation of the gradients to create regional isotherm, temperatures at specific depths (Figure 10), and prediction uncertainty maps.

This methodology has been developed and applied world wide, along with maps of uncertainty, as well as estimated depths to key isotherms (Steen and Nadeau, 2007; Nadeau and Steen, 2007).

An important lesson learned in the last 6 months is that close attention must be given to nearest neighbor observations which deviate significantly from the interpolated regional geothermal

¹¹ Corresponds to Figure 6. The creation of the Mississippi Canyon by massive marine slumping ~17,000 year BP may be responsible for anomalously low LOP observations (see text).

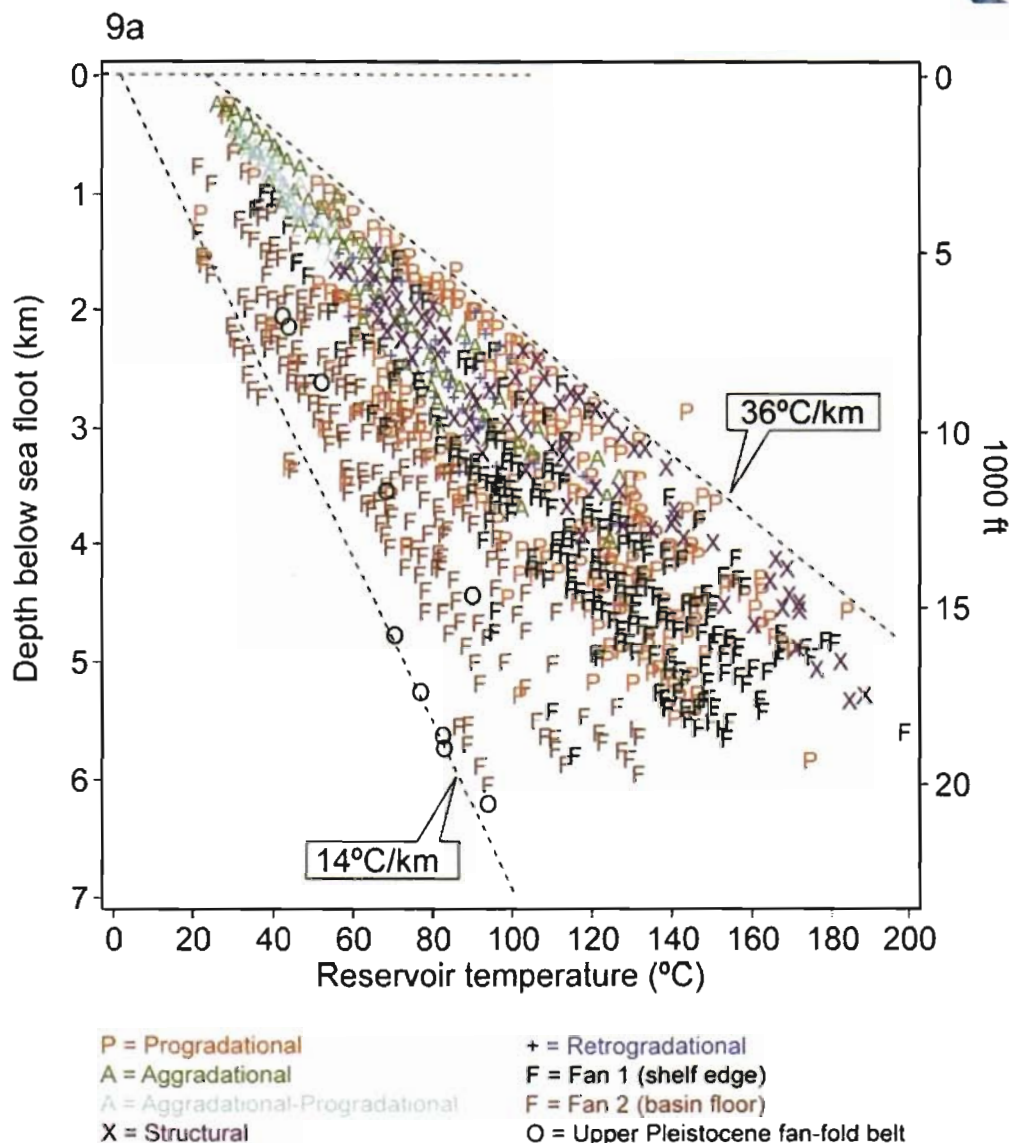


Figure 9a – Reservoir temperature related to depth below sea floor (Gulf of Mexico).¹²

gradients. In these cases more weight should be given to these nearest neighbor control points, particularly when they are <10km from drilling targets, to better predict the temperature and pressure of drilling targets. When the resulting probability distributions for pressure are combined with the LOP probabilities, a depth map for drilling safety margins can be generated to support well planning and operations.

¹² Ehrenberg et al., 2008.

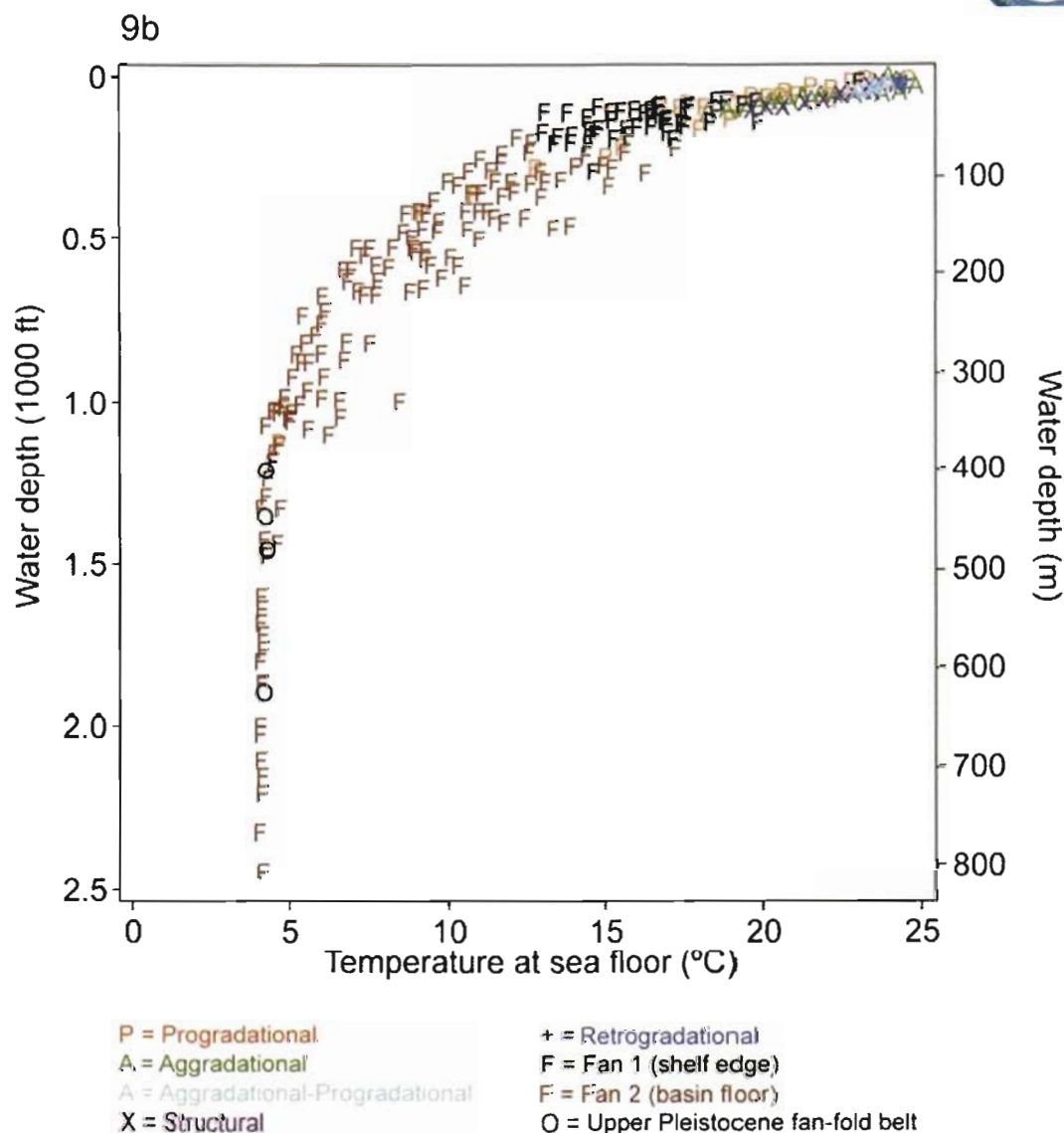


Figure 9b – Sea floor temperature related to depth below sea level (Gulf of Mexico).¹³

6 Recommendations

To implement these lessons learned, it is recommended that license operators provide a pre-drill temperature and pressure prognosis, as well as uncertainties, with the appropriate applications for drilling activities. A geologically competent organization should be commissioned to compile, evaluate, analyze, create forward models, and continuously update these with post-drill findings to track and transfer experience within the industry. The industry should define HPHT drilling conditions as pressures $>1.4 \text{ g/cm}^3$ equivalent mud weight and temperatures $>120^\circ\text{C}$, as a more rigorous indicator of overpressure risks than the $>1.7 \text{ g/cm}^3$ and $>149^\circ\text{C}$ (300°F) values currently used. Sub-surface formation integrity tests, in the form of fracture initiation, minimum stress, and

¹³ Ehrenberg et al., 2008.

leak off pressures (LOP) should also be compiled, evaluated and mapped in order to develop probabilistic as well as geological models of drilling safety margins with respect to anticipated reservoir pressures. Regular reports of these findings should be made to the public record, as well as available online, in order to disseminate this information to the energy industry and other research organizations. The overall objective should be to facilitate the rapid development of technical expertise and operational practice, as well as reduce the risks of future safety incidents and harm to marine and related environments.

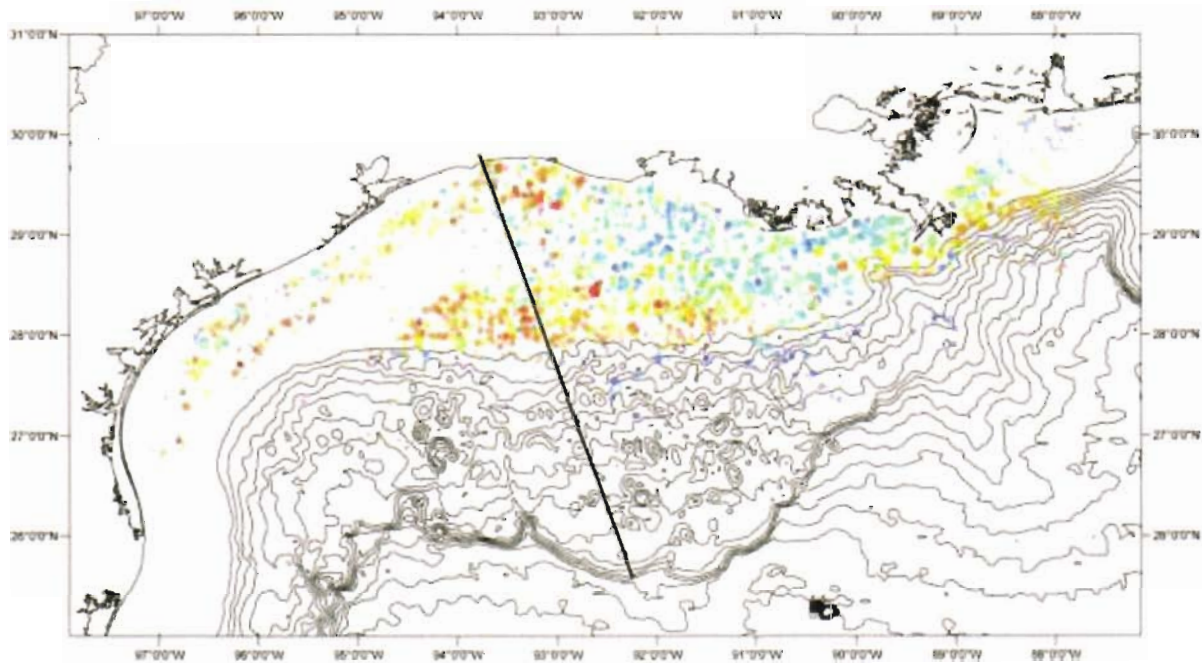


Figure 10 - A GoM map showing the estimated geothermal gradients.¹⁴

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¹⁴ Based on BOEMRE reservoir and NOAA sea-floor temperatures, including data from Ehrenberg et al., 2008 (line of section for Figure 4 is also shown for reference). Water depth contours are at 200 m intervals. Estimated thermal gradient in color: red = high, blue = low.



8 References

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