IPSP in "Hydrocarbon Exploration and Exploitation"

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Abstract

Drilling through salt

This thesis discusses the geological setting of evaporites associated with hydrocarbon deposits, as well as the technical challenges and solutions when drilling through them. Evaporites are divided accordingly to the changes that they have undergone in their primary structure and composition and can form either source rocks or seals and traps for hydrocarbons. Due to their physical, logging (porosity, density), and mechanical properties, salt formations behave in extremely hazardous ways when it comes to drilling. For this reason, drillers of the past were trying hard to avoid them. However, the ever-increasing demand for energy has led the oil industry to search for solutions to exploiting the extensive oil and gas reserves discovered below the continental shelves, and under thousands of meters of water and thick layers of salts. Hence, new technologies have been developed to manage the risks and to drill safely above, through, and below salt formations.

This thesis provides an overview of evaporites regarding geology and tectonics and examines their origin and evolution over time, their classification and structure, as well as their association with hydrocarbons, either as source rock or as seals and traps. It presents the main evaporitic minerals along with their physical properties, logging and mechanical properties, and behavior of salt formations. It examines the hazards that come with salt drilling while stating possible or inevitable outcomes if these hazards are not taken into account. It also discusses the challenges that drilling engineers must meet when drilling above, through, and beneath salt formations.

It then discusses enabling and emerging technologies and methods used in salt drilling, by mentioning some aspects of well design, like subsalt imaging, and of drilling operations, like BHA design, bit selection, etc., as well as well control and drilling fluid selection. The conclusions of this thesis highlight the complexity of salt drilling and the importance of systematic practices and developments to move on to an era when hydrocarbons associated with salts are exploitable with no major risks.

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CHAPTER 1. INTRODUCTION

The current thesis discusses the technical challenges and solutions in drilling through salt formations, evaporites[1] , and salt domes. These formations raise significant difficulties during drilling. For this reason, drillers of the past were trying hard to avoid them. However, the ever-increasing demand for energy has led the oil industry to search for solutions to exploiting the extensive oil and gas reserves discovered below the continental shelves, and under thousands of meters of water and thick layers of salts. Hence, new technologies have been developed, to manage the risks and to drill safely through salt formations. This thesis discusses the geological setting of evaporites associated with hydrocarbon deposits, as well as the technical challenges and solutions when drilling above, through, and below them.

This thesis is based on an extensive literature review to answer critical questions regarding the creation of salt formations, their association with hydrocarbon deposits, their properties, behavior, and the challenges faced when drilling through them, as well as the evolution in technological solutions and new techniques to meet these challenges.

The current thesis is structured as follows:

Chapter 2 provides an overview of evaporites regarding geology and tectonics, examines their origin and evolution over time, their classification and structure, as well as their association with hydrocarbons, either as source rock or as seals and traps.

Chapter 3 briefly presents the main evaporitic minerals along with their physical properties, logging and mechanical properties, and behavior of salt formations.

Chapter 4 examines the hazards that come with salt drilling, like the occurrence of shear and rubble zones or inclusions and “dirty salts”, etc., while stating possible or inevitable outcomes if these hazards are not taken into account. This chapter also discusses the challenges that drilling engineers must meet when drilling above, though, and beneath salt formations.

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[1]* **It is noted that evaporites are also referred to as evaporates. In this work the word evaporites is used, since it seems to preferred by the majority of scientific publications.**

Chapter 5 discusses enabling and emerging technologies and methods used in salt drilling, focused on some aspects of well design, like subsalt imaging, and of drilling operations like BHA design, bit selection, etc., as well as well control and drilling fluid selection.

Chapter 6 presents the conclusions of this thesis that highlight the complexity of salt drilling and the importance of systematic practices and developments to move on to an era when hydrocarbons associated with salts are exploitable with no major risks.

CHAPTER 2. EVAPORITES AND HYDROCARBONS

2.1 Evaporites – An Overview

Evaporites are sedimentary rocks formed by the deposition of salts from brine solutions as the water is lost by evaporation and the ion concentration becomes higher. According to Warren (1999) (Warren, 1999), evaporites are rocks formed by saturated debris (salt content>50‰) on or close to the earth's surface and their formation is due to solar evaporation. This concept covers a broad spectrum of salts that have been chemically deposited, including alkaline carbonate rocks. Other researchers restrict the name "evaporite" to those salts created by the evaporation of ultra-saline water, which were only on the surface of the earth. The evaporitic minerals deposited depend on the saturation of the residue in specific ions. For example, if the residue is saturated with SO_4 and Ca^{+2}, anhydrite ($CaSO_4$) or gypsum ($CaSO_4.2H_2O$) is deposited, while when it is saturated with Na^+ and Cl^-, halite (NaCl) is deposited.

Based on the above, evaporites were formed only on the surface or very close to the surface of the earth. However, some evaporites were formed at greater depths and are associated with other processes, as will be discussed below. Upon immersion, evaporites dissolve or transform due to their contact with fluids and debris of the phreatic, active zone or with fluids and debris from processes that take place within the basin outside this zone. (Manoutsoglou & et al, 2010)

Taking into account the procedures of evaporite formation, it is possible to understand the formation of salt domes, through the concentration of a thick bed of evaporite minerals. Salt domes are thick formations created from natural salt deposits that, over time, leach up through overlying sedimentary layers to form large dome-type structures. They are very large bodies of salt that can be as large as several miles in diameter, and up to 30,000 ft in height, consisting of nearly pure sodium chloride (usually >95%).

Salt beds are shallower, thinner formations. These formations are usually no more than 1000 ft in height. Bedded salt formations differ significantly from salt domes. Bedded salt formations consist of "layers" of salt interbedded with non-salt rocks, such as shale, dolomite, and/or anhydrite. Bedded salt formations can vary considerably from one another. Additionally, a bedded salt formation within a specific basin can vary from one part of the basin to the other. (Speight, 2019)

The oil and gas industry pays major importance to salt formations. Characteristics such as their more than enough deformation capabilities and low permeability are what make saline formations crucial. It is qualities like those that make salt formations sizeable hydrocarbon traps, thus exploitable oil or gas reservoirs. (Salmazo, Mendes, & Miura, 2013)

It should be noted that usually salt-related oil and gas traps are to be found in salt ridges, pillows, or undeformed bedded sedimentary layers of salt, apart from salt domes and tongues. Not only that but, those traps can be met as mixed domains, as in margin basins located in the South Atlantic, in the Scotian – Canadian Shelf, and in the territory of the southern North Sea.

Great examples of salt-associated and remarkably big hydrocarbon reservoirs are the domal structures located in Mexico's Gulf, where salt was deposited in the Tertiary, while there are other salt tongues in the periphery. Moreover, relevant traps can be found in Kazakhstan (Tegiz and Kashagan), in the North Sea (were salt was deposited in the Cretaceous), in the Williston basin, or others located offshore in West Africa and Brazil (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

Up until 1980, oil and gas companies didn't consider it profitable to run exploration and exploitation surveys when it comes to hydrocarbons trapped beneath salt formations. The difficulties of drilling through salt made them lose interest quickly. With the passing of the years and the increase in energy demand, investing in overcoming such difficulties led to an embrace of an era where scientists put great effort into understanding salt behavior. Consequently, in the early 80s' and beyond, meeting salt structures in the exploration process came to be from negative to positive news. (Haquet, 2013)

Lately, with the improvement of exploration methods &techniques, the gas and oil industry is searching for hydrocarbons in deeper basin zones. In the aforementioned regions (the Gulf of Mexico, the North Sea, etc.) huge quantities of hydrocarbons were found under huge, thick salt structures. These are specified as <u>pre-salt deposits</u>. The pre-salt deposits vary significantly from the <u>subsalt deposits</u> discovered already. (Dribus, Jackson, Kapoor, & Smith, 2008)

Pre-salt deposits are located within formations that were formed before the deposition of autochthonous salt. Autochthonous salt is defined as the salt that remains more or less on the original stratigraphic level or surface on which it is deposited. This autochthonous salt lies above more ancient rock formations and is, subsequently, covered by more recent layers. On the contrary, sub-salt deposits are located underneath salt domes of allochthonous salt, which are usually tectonically active. Allochthonous salt is a mass of salt formulated from the original autochthonous layer that ascended by penetrating overlying layers, whether on land or in the ocean, and it afterward spread horizontally (Figure 2-1).

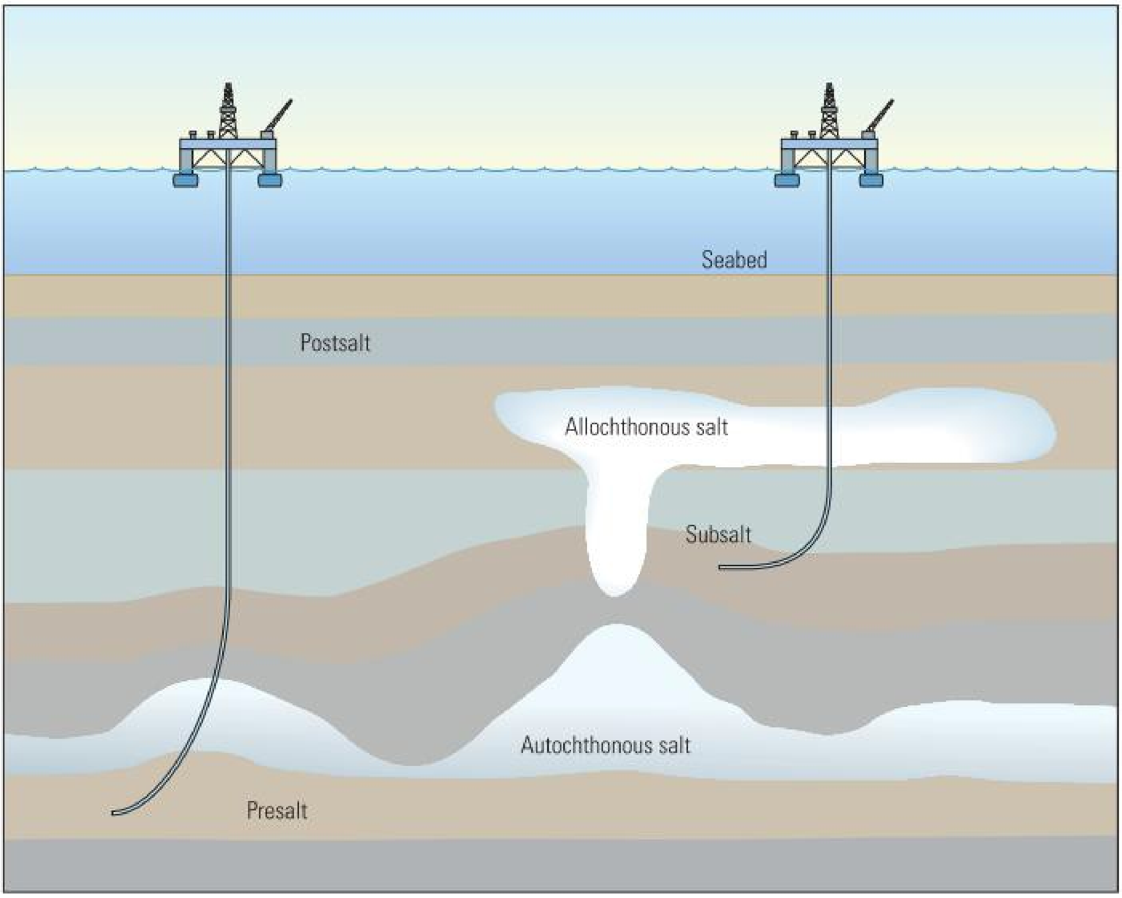

Figure 2-1:Sub-salt and pre-salt hydrocarbon deposits under salt formations (Beasley, et al., 2010)

Evaporites according to the changes that have undergone in their primary structure and composition, can be divided as follows (Warren, 1999):

1. <u>Primary evaporites.</u> They are formed from the precipitants due to evaporation at normal temperatures, and due to solar radiation from accumulations of brine water (lakes or larger basins).

2. <u>Secondary evaporites.</u> They constitute the largest percentage of old evaporative deposits and are divided into three subcategories:

   2.1. *Subsurface deposition of salts of shallow depth.* The reason for their formation is still the effect of sunlight (Sabkha tubers).

   2.2. *Evaporites affected by diagenesis due to burial.* At temperatures typically greater than those on the earth's surface, the initial evaporitic minerals are partly altered to new mineralogical phases.

   2.3. *Underground precipitation of evaporitic compounds in the form of adhesive material or as substitutes for non-evaporite materials.*

3. <u>Tertiary evaporites.</u> They are formed during the ascent and subsequent erosion of the secondary evaporites which had been found at great depths. Thereupon they come into contact with dolomites which are enriched with dissolved material from the dissolution of pre-existing evaporite layers. This process took place either in a phreatic circulation zone (with the active flow) or in zones of brine. These evaporites have undergone significant changes in their structure, almost completely altering their primary characteristics.

Based on the order of deposition of evaporitic minerals from brines with a gradually increasing concentration due to continuous evaporation, two major groups of evaporitic minerals can be distinguished (Warren, 1999):

1. Evaporitic alkaline earth -carbonate minerals (aragonite, dolomite, low magnesium calcite, and high magnesium calcite).
2. Evaporitic salts (gypsum, anhydrite, halite, sylvite, carnallite, trona, etc.).

Primary evaporitic carbonate minerals tend to form in the early phases of brine concentration, while primary evaporitic salts form when the salinity becomes higher. Specifically, evaporitic carbonates are formed from brines with salinity rates of 35-140‰. This is translated into a loss of water at a percentage of 0-75%, due to evaporation in a closed basin (i.e. a basin where no inflow and outflow of fluid is observed). Evaporitic salts are deposited from brines with a salinity of 140-250%, where water loss due to evaporation is higher than 75-85%.

The formation of primary evaporitic deposits, therefore, presupposes the existence of a dry to semi-arid climate and water loss due to evaporation at a rate higher than the rate of water inflow into the basin (from surface water and precipitation). Based on this, old evaporitic deposits are important paleoclimatic indicators. Also, evaporitic carbonates may contain and retain increased organic substances which later may create hydrocarbons or constitute a reducing agent for base metal sulfides. In contrast, evaporitic salts have in general a very low organic content. (Alevizos & Galetakis, 2005)

As mentioned above, in a basin where the salinity of brine gradually increases due to evaporation, the evaporitic carbonates are deposited first, and then the evaporitic salts. Thereof, two basic characteristics emerge for both types of evaporitic deposits. First, the continuous changes in the water level, mainly in the basin periphery, explain the alternation of land (coastal) deposits with deposits that are formed below the water level (water deposits). That is, any water deposit when it emerges to the surface will be subjected to disintegration and diagenesis, acquiring land-based deposition characteristics. Second, the dissolved content of shallow brines, mainly the ratio of Mg^{+2}/Ca^{+2}, changes as salinity changes. For example, the Ca^{+2} content of the deposit decreases as pure calcite or calcite with a low Mg^{+2} content is formed. The next carbonates that will precipitate from the brine, which now has an increased ratio of Mg^{+2}/Ca^{+2}, will be dominated by calcium with a high content of Mg, magnesite, or even dolomite. (Alevizos & Galetakis, 2005)

The basin in which the evaporitic minerals are deposited can be located either in a coastal area (e.g. lagoon) or an inland area (e.g. lakes). In the first case, the resulting evaporites are considered to be of marine origin, and in the second case of mainland origin. Their differences are in the different deposition environments and in the different components of the debris from which they come. Because marine evaporites come from seawater with a more or less stable composition, their chemical properties can be expected up to a certain degree. The Na_2CO_3 salts commonly found in lake evaporites are absent from marine salts. In contrast, potassium salts when bound to salts containing significant amounts of $MgSO_4$ indicate only marine origin.

2.1.1 Continental or non-marine evaporites (primary evaporites)

Formation of evaporitic minerals of continental origin took place in closed lake systems that grew mainly in areas of dry and semi-arid climate, where the amount of evaporating water is greater than the amount of inflowing water. The type of evaporitic minerals depends on the lithology of the catchment basin (volcanic or sedimentary rocks). In enclosed lagoons there are two sorts of precipitation processes (Melvin, 1991):

1. Reduction of the volume of lake water due to its evaporation in a larger amount than the amount of water flowing into the lake from rivers or rainfall. As a result, the lake shrinks as it dries up and a Sabkha environment is formed. This process takes relatively little time. The evaporitic minerals deposited reflect the amount and the type of dissolved salts contained in the lake water.
2. The volume of the lake water remains, on average, stable. However, the water salinity gradually rises due to the content of river inflow with plenty of dissolved salts.

Thick formations of non-marine evaporites may appear where evaporation velocity surpasses inflow, where inflow is adequate to supply solutes, and where the inflow gathers in an enclosed basin (Melvin, 1991) or where the outflow is limited. Dry or semi-dry conditions appear worldwide in high-pressure belts of the subtropical areas and near the poles, as well as in the midlatitude intracontinental deserts and North American and Asian steppes (areas secluded from sea moisture), and in orographic (rain shadow) deserts that exist in every possible earth zone (Figure 2-2). Solutes are brought by streams and waterways, groundwater, springs, rain, and by wind-blown mist and dust. Enclosed basin conditions can happen under a variety of circumstances (Melvin, 1991):

1) tectonic valleys, incorporating fault-related intermontane valleys and intracratonic tectonic sinks,
2) interdunal sinks in sand oceans,

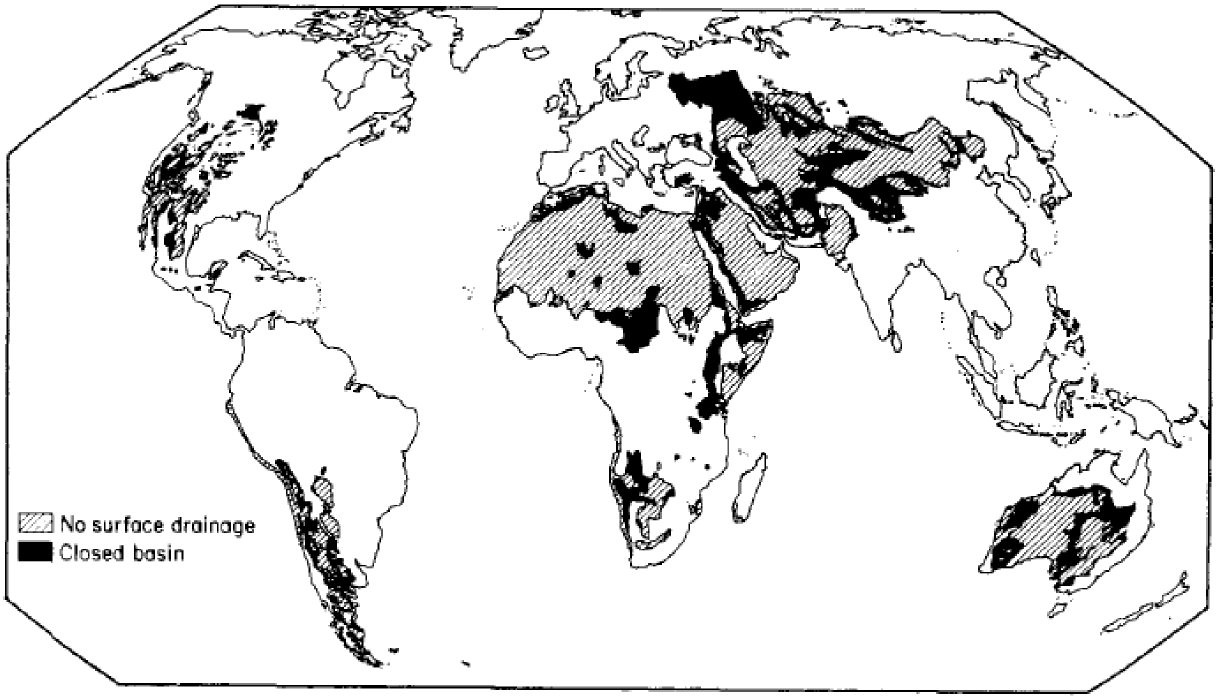

Figure 2-2: Areas of the world (without Antarctica) with no surface drainage and areas with closed basins signifying the occurrences of continental evaporites (from Cooke & Warren, 1973) (Melvin, 1991)

3) hollows created by wind deflation,
4) closed or deserted frozen valleys or fluvial channels,
5) volcanic or meteor crater holes, and
6) combinations of at least two of the above-mentioned.

Orologic deserts in intermontane basins surrounded by faults produce the thickest non-marine evaporite deposits. Moisture caught in the neighboring mountains constitutes solutes to the basin, while the climatic and tectonic setting permits the basin to be a long-lasting sink for water and sediment.

2.1.2 Marine evaporites (primary evaporites)

Normal seawater presents a density of 1.025 g/cm^3 and has about 35 g/l of diluted components. The following salts (without water in their structure) can potentially be created from these components (in% by weight of total salt content) (Figure 2-3):

- 78% NaCl (halite)

- 18% potassium salts, such as chlorides and sulfates of K and Mg (sylvite KCl, carnallite $MgCl_2.KCl.6H_2O$, kieserite $MgSO_4.H_2O$, etc.)
- 3.5% $CaSO_4$ (gypsum and anhydrite)
- 0.3% carbonates plus other minor components

The most common environment for the deposition of marine evaporites is the shallow marine environment and the deep basin environment.

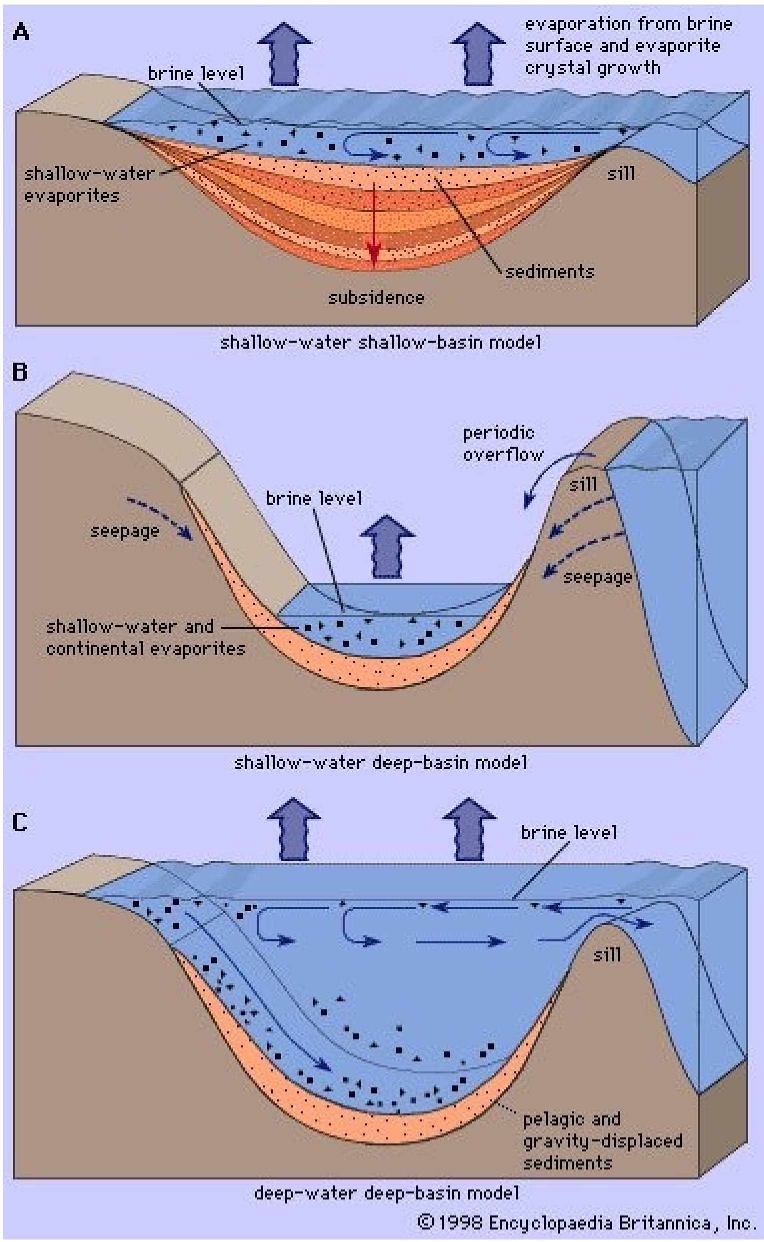

Figure 2-3: Mechanisms of marine evaporites depositions (Britannica. The Editors of Encyclopaedia, 2019)

Evaporite deposition in *__shallow marine conditions__* (frequently named “salina”) takes place in arid shore sides, especially on the boundaries of alike semi-confined water accumulations as in the Persian Gulf, the Gulf of California Gulf and the Red Sea. Confinement is, by and large, a basic necessity for evaporites to be deposited, since unrestricted blending with the waters of the ocean would permit the water masses to effectively beat the large evaporation amount of desert regions and decrease the salinity to a value near the salinity of salt water. This semi-confinement cannot, indeed, stop a lot of blending to take place, as seashore topography is the main element related to the creation of brine. Evaporites that are formed in small depths, particularly halite, anhydrite, and gypsum, frequently form interpenetrating wedges with dolomite and limestone, as well as, with fine-grained mud rock., in plains of tides.

The greater part of thick, widespread evaporitic layers seems to have been created in *deep, confined basins of great depth* that were formed at the time of drought around the world. Aridity is the most essential prerequisite for evaporites to be created since water should evaporite more quickly than it may be recharged by inflow and/or precipitation. What's more, the evaporite basin should be confined or at the very least partly secluded from the high seas for brines created after evaporation not to be allowed to return to the ocean. Confining brines into such a confined basin for an extended duration produces their concentration up to the degree when evaporitic minerals start to precipitate. Intermittent brake of the confinement, as a result of either subsidence of the earth's crust or the rise of the ocean water level worldwide, recharges the basin now and then with sea water, subsequently renewing the volume of seawater to be evaporated and creating the extremely thick, locally widespread evaporite deposits.

The shallow-water, deep-basin model shows the brine level in the basin beneath the level of the sea as a result of evaporation; brines are replenished by groundwater recharge from the open ocean.

Discussion regarding the creation of thick evaporitic layers is ongoing. There are three probable cases for confining "barred" evaporite basins, which vary greatly, and none of them have gained significant consent. The model of a deep basin with deep water provides a rational for recharging the basin across its boundaries or inner limits, with gradual accumulation of thick evaporites due to the flow out of brine towards the sea that preserves a steady brine concentration. The model of a shallow basin with shallow water delivers thick evaporites by the continuous sinking of the basin floor. Finally, the model of a deep basin with shallow-water demonstrates the brine level in the basin below the sea level due to evaporation; brines are renewed by groundwater replenishment from the open sea. (Einsele, 2000)

2.1.3 Diagenesis and geochemical features of evaporites (secondary and tertiary evaporites)

Primary evaporitic deposits are strongly influenced by diagenesis, after their burial. The relevant processes, either mechanical or physicochemical, result in the destruction or replacement of primary minerals and structures, and the creation of new ones. In this way, the primary evaporites are transformed into secondary and tertiary, as mentioned at the beginning of the chapter. The procedures related to the diagenesis of evaporites are (Jiang, Worden, Cai, Shen, & Crowley, 2018):

1. Cementation during the initial and final stages of diagenesis
2. Substitution of the minerals existing before diagenesis
3. Solubilization of underground minerals
4. Alteration in the different mineral stages along with water liberation

The time path throughout which the evaporites are formulated can be summarized in Figure 2-4 below:

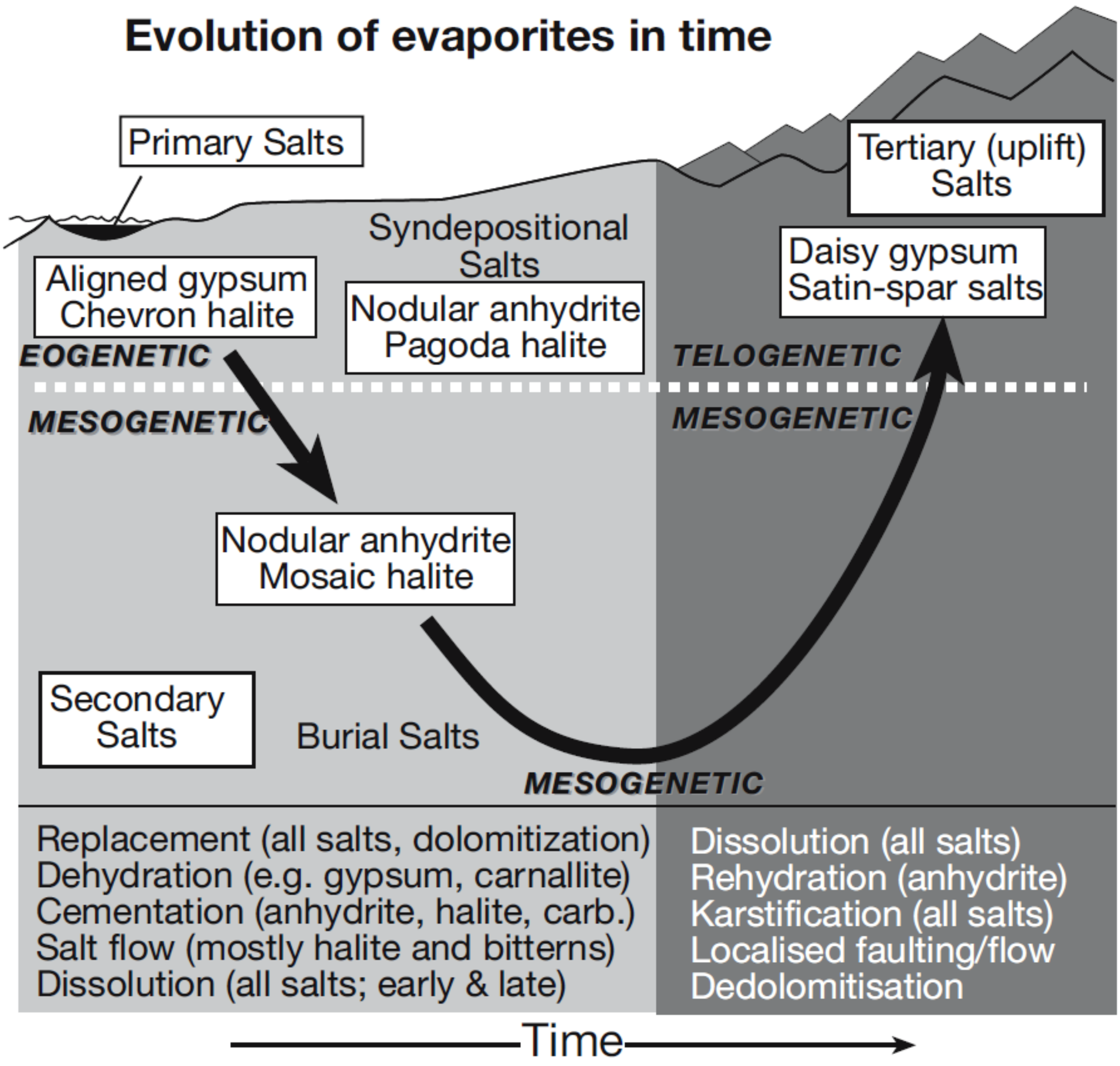

Figure 2-4:Evolution of evaporites over time (Warren, 2006)

Diagenesis is determined by the fluid flow regime prevailing at different depths. Such schemes are the following (Figure 2-5) (Einsele, 2000):

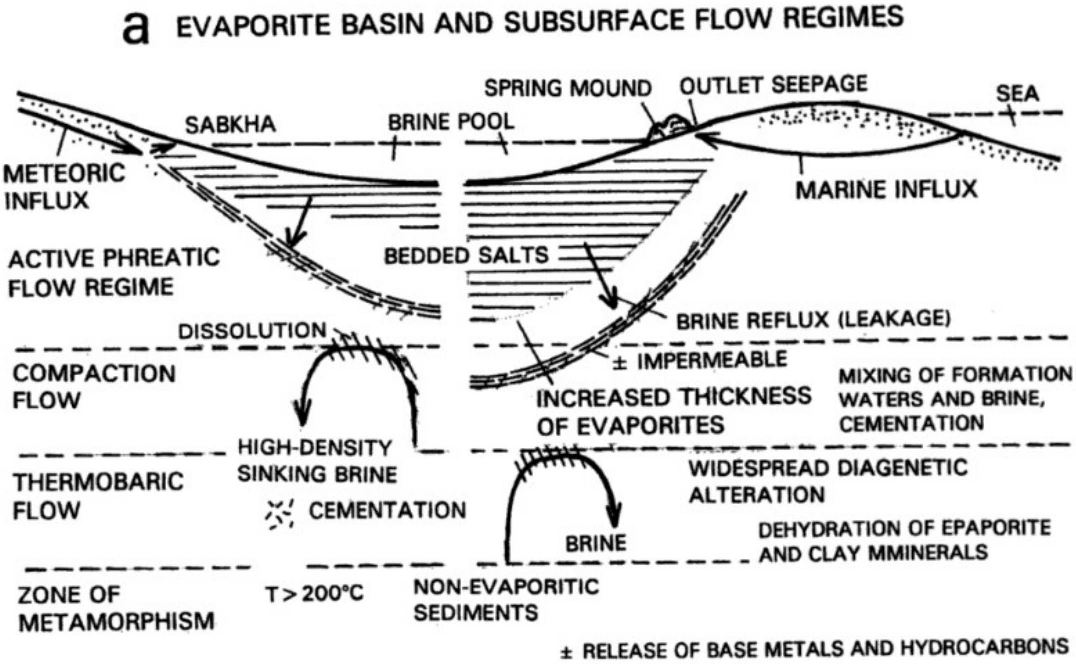

Figure 2-5. Evaporite basin and underground flow patterns below it (Einsele, 2000)

1. Salt deposits having an effective phreatic flow system of rain water/brine either inside or beneath them. Fluids with a variety of chemical compositions can be produced by the inflow of any kind of water (rain water/brine/sea water) from the basin's margins and the sinking of brine from the salt buildup (brine reflux). These flows of various chemical syntheses take place within and below the primary evaporitic deposits interacting in a complex way with the buried salts of decreasing permeability over depth.

   It is during this flow system that primary minerals dissolve, many of these minerals are replaced, and new minerals are formed. For instance, halite may replace primary gypsum (Figure 2-6), and pre-evaporitic limestone may be replaced by secondary dolomite. All these happen bellow the center of the basin where greatly salinated brines descend underground.

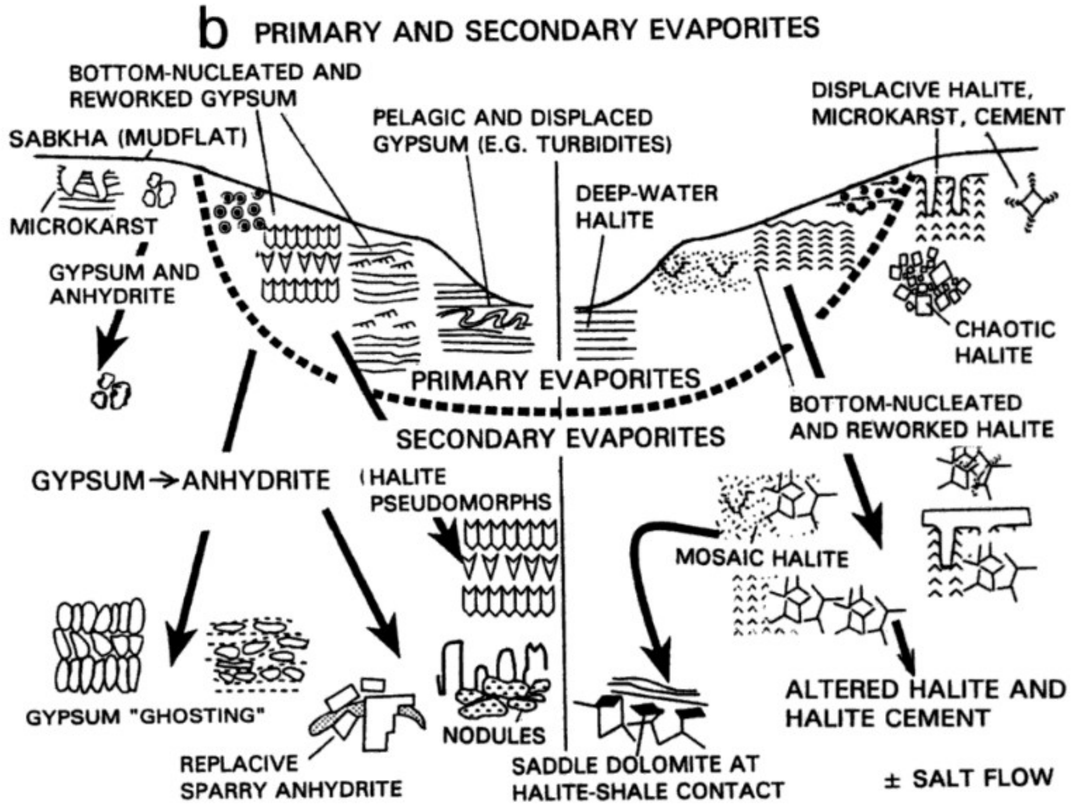

Figure 2-6. Primary and secondary evaporites of gypsum/anhydrite system (left) and halite system (right) (Einsele, 2000)

2. Expulsion of pore water due to compaction. The thickness of evaporitic deposits can vary significantly as a result of the mechanical compaction of evaporites, depending on their porosity and type (primary vs. secondary deposits). Differential compaction of early calcium sulfate deposits, which are only partially cemented, can be one of the processes for the formation of collapse breccia (Figure 2-7). During their flow, the fluids can dissolve pre-existing evaporitic minerals, modify earlier sediments and deposit recent minerals such as cement (Warren, 2016). After this decomposition process numerous products are left behind, like breccia from evaporitic dissolution, and silicated and calcicated evaporitic tubers. For instance, the dolomitization of calcareous material or calcification of dolomitized strata might result from the constant of fluids with sediments.

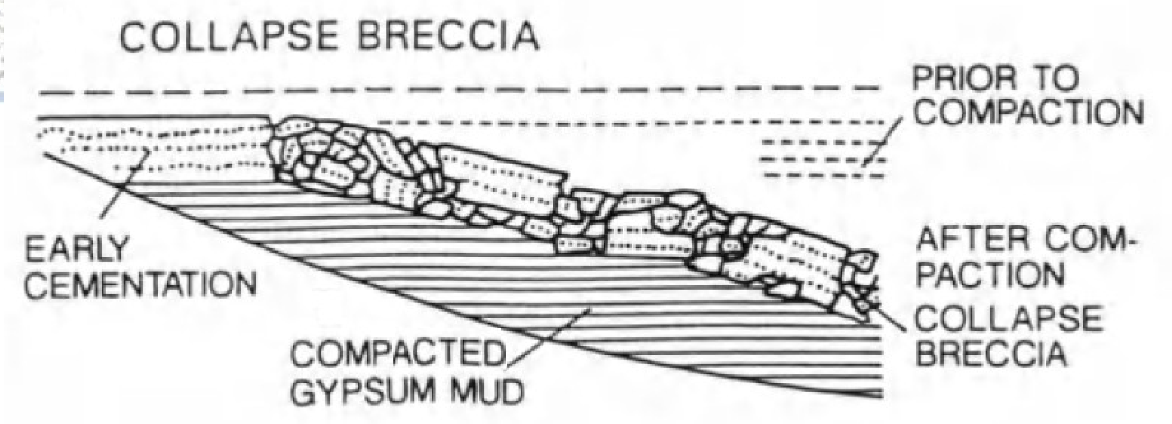

Figure 2-7. Collapse breccia caused by early cementation of top layers and subsequent differential compaction (Einsele, 2000)

3. Thermo-gravitational flow caused by differential pressure and delivered by the exsiccation of evaporitic and clay minerals. If temperature and pressure are moderately increased, then phase changes of several minerals may be included. Clay and hydrated salt minerals discharge water and supply a flow system that is initially directed upwards (thermo-gravitational flow). If the pores contain saturated brine solution, primary gypsum is transformed to anhydrite at temperatures 35-45°C. In case the concentration of brine is lower, then the conversion of gypsum to anhydrite requires temperatures between 50°C and 60°C and a burial depth of a few hundred meters. Carnallite releases Mg^{+2} and water when it is converted to sylvite (KCl) at temperatures of 40-50°C. Polyhalite and kieserite are transformed into other minerals if the temperature is higher. In all cases, water is released which, if it does not find flow outlets, it causes an increase in pore pressure and invokes deformation of the surrounding formations. Such deformations are the small diapiric structures in sulfate deposits. If volume loss in the subsurface by sub-solution and/or phase changes occurs concurrently with the precipitation of overlying salts, the basin floor becomes depressed. As a result, thickened salt deposits are formed locally or in limited parts of the basin (Figure 2-8).

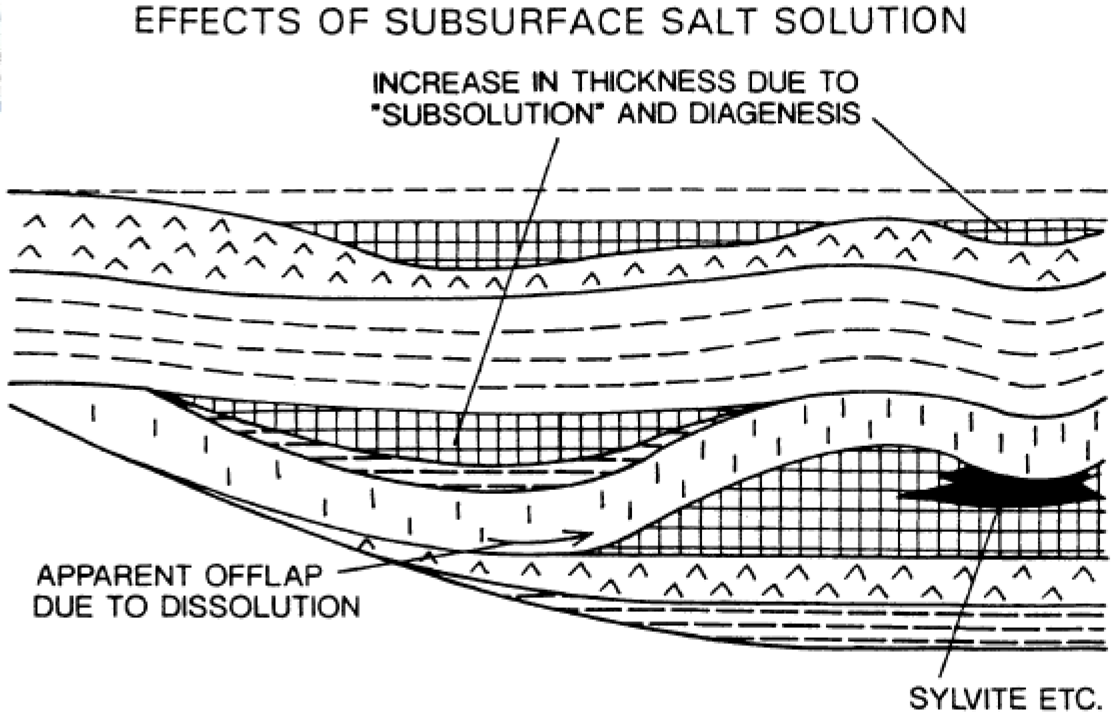

Figure 2-8. Effects of large-scale underground dissolution of halite and transformation of salt minerals that contain water, like carnallite, into salts without water, like sylvite, on stratigraphic relationship and thickness of subsequent evaporite deposits. (After Kendall,1988) (Einsele, 2000)

4. Fluids in the formation pore in deeper zones where metamorphism takes place at temperatures above 200°C (burial metamorphism).

2.1.4 Exposure of underground evaporites (tertiary evaporites)

The rise and erosion (exhumation) of evaporites inhumed at great depths, lead to further changes in already diagenetically modified evaporite salt deposits. When they come in contact with water during their ascent, then the most soluble salts dissolve. This can be done at depths of a few hundred meters, like in the deep phreatic zone. As the anhydrite takes up water, itis gradually converted into gypsum (Einsele, 2000). This process causes the formation to swell and rupture. The resulting discontinuities are filled with fibrous gypsum or halite deposited from saturated brine. Nearer to the piezometric surface, where more rain water is now circulating, the dissolution of evaporites dominates, such as the karstification of sulfates. From this point on, the volume of sulfates dissolved is greater than the volume required for anhydrite to convert into gypsum.

2.2 Evaporites and hydrocarbons

2.2.1 Evaporites as source rock

In general, for an effective source rock for hydrocarbons to be formed, certain conditions must be satisfied:

1. The organic matter should not be extensively dissolved during sedimentation
2. The organic matter should be a type that can produce hydrocarbons
3. The organic matter should not be eliminated due to the action of microbes during sedimentation and early diagenesis
4. The organic matter should be exposed to appropriate temperatures for periods so that its diagenetic transformation into hydrocarbons can occur.

There is plenty of evidence to show that the evaporite environment can generate large quantities of organic matter and preserve it afterward. However, whether evaporites may be significant source rocks for hydrocarbons is difficult to say, because of the scarcity of data on the actual contents of TOC (total organic compounds) or extractable hydrocarbons (HC) in these rocks. The recognition of the full suite of rocks created by the evaporite environment appears to be part of the issue.

Regarding evaporitic carbonates, Kirkland and Evans (1981) (Kirkland & Evans, 1981) have highlighted the significance of the carbonates formed during the vitasaline stage[2] (their mesosaline stage) as source rocks, since deep-water evaporitic environment satisfies the first three of the conditions mentioned above, and is capable of producing great quantities of rich, immature source rock. Measurements made in the present day in evaporite environments have shown that vitasaline is not the stage of peak organic productivity. In any case, the rather low productivity of the vitasaline stage is compensated by the fact that this stage demonstrates the slowest sedimentation rate during the evaporite depositional cycle. For instance, in a marine evaporite basin, it may be expected carbonate rock depositional rates be as high as 1:400 or higher when compared to halite. In this manner, even though the deposition rate of organic matter may be higher at higher salinities, it will be exposed to more sediment dilution.

[2]Adams and Rhodes (1960) defined vitasaline as the salinity between 35 and 72‰, the range where most marine organisms can survive. However, salinity ranges were modified based on Warren (2006), reflecting current terms of saturation stage boundaries for evaporite minerals: seawater ~28–38‰, mesosaline ~38–140‰, hypersaline, which is divided into penesaline 140–350‰ (gypsum/anhydrite-halite) and supersaline>350‰ (halite and bitter salts).

2.2.2 Evaporites as seals and traps

Regarding sealing capacity and durability against fracturing the best sedimentary seals for hydrocarbons are gas hydrates, then evaporites, and finally shales. To seal a commercial deposit of oil and/or gas, any sealing formation or lithology should be extended on every side, retaining stable properties over sizable extents, being considerably ductile, and extending over a sedimentary basin. For a seal to be effective the displacement pressure[3] applied by it should be larger than the buoyancy pressure of the hydrocarbon column below. The displacement pressure of a seal is affected by its physical properties, such as pore radius and pore size profile, as well as by the physical properties of hydrocarbons, such as interfacial tension and wettability. Consequently, the size of pores and the density of the entrapped hydrocarbons and water are critical in deciding whether a specific lithology can act as an effective seal or not.

Clathrates are the most effective seal for hydrocarbons, followed by evaporites for any type of structural setting and type of hydrocarbons. Evaporite seals present amazingly high capillary entry pressures[4], ductility, extremely low permeability, and considerable lateral extents, and can maintain seal integrity over extensive areas, for a broad range of underground pressures and temperatures. A shale seal typically presents a range of permeability from≈10^{-1} to 10^{-5}mD, and rarely even lower values of 10^{-8}mD (Figure 2-9). Quantitative measurement of evaporite permeability is past the limit of standard instruments utilized in the oil industry and is generally a subject of study for engineers Their work shows that the permeability of halite is of the order of a nanoDarcy or less. Intact underground salt's estimated permeability is under 10^{-21} m^2 (10^{-6}mD) with the tighter halite presenting permeability from ≈10^{-7} to 10^{-9}mD and the typical massive anhydrite as low as ≈10^{-5}mD (Beauheim & Roberts, 2002).

[3]**Displacement pressure is the pressure required to push hydrocarbons into a rock's pore space and create a continuous hydrocarbon deposit.**
[4] **Capillary entry pressure (or liquid entry pressure) describes the pressure that a non-wetting fluid (e.g. CO_2) must overcome to displace water contained by capillary forces in the pores of a rock or sediment.**

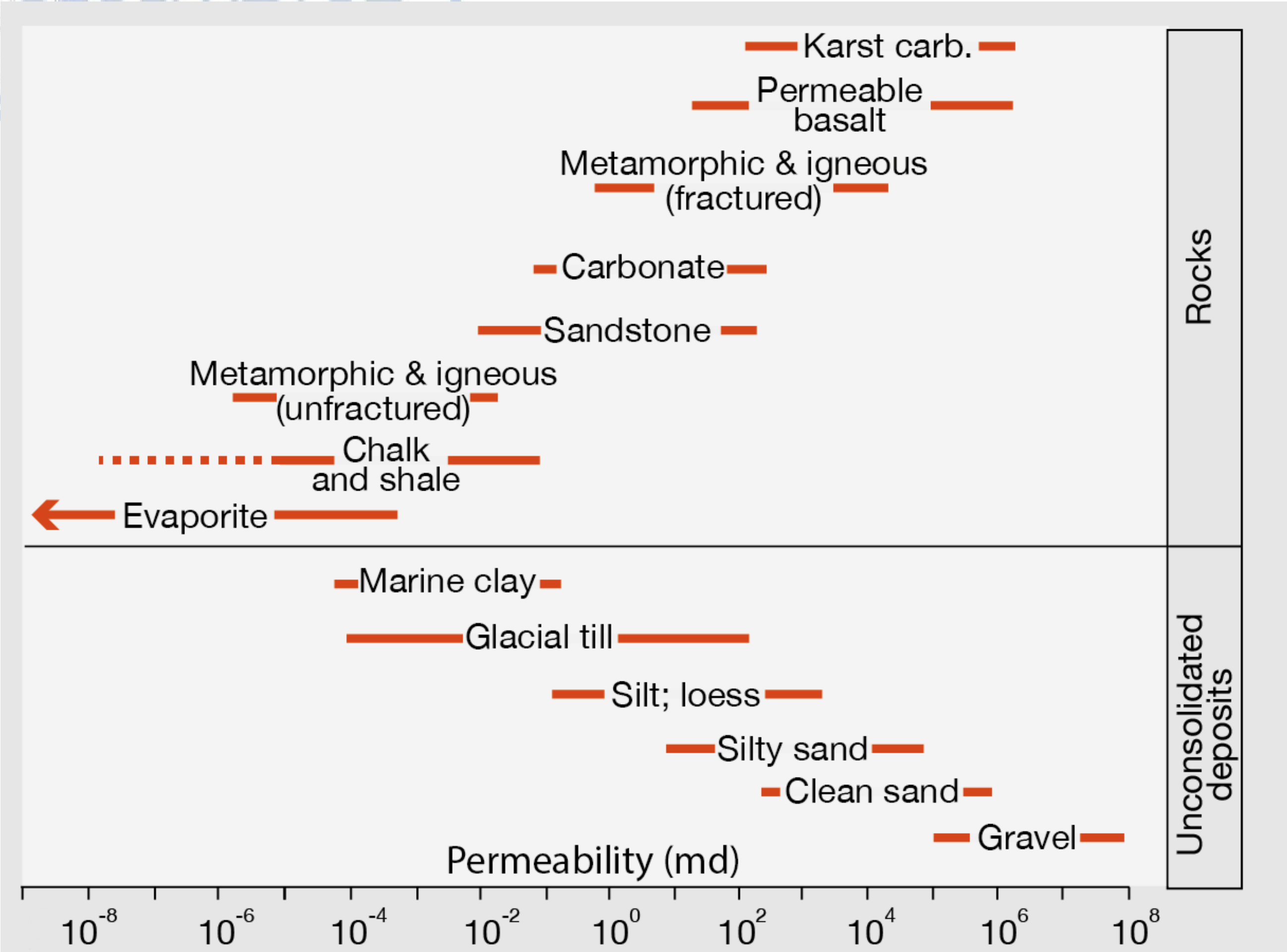

Figure 2-9. Permeability of unconsolidated deposits and rocks (Saltwork Consultants Pty Ltd., 2021)

Evaporite beds and allochthonous evaporite domes set up some of the most effective long-term underground bounds to the upward movement of hydrocarbons in a sedimentary basin acting both as a seal to hydrocarbons deposits and also in CO_2 sequestration (Saltwork Consultants Pty Ltd., 2021).

Apart from permeability, some other factors affect the ability of a seal to retain hydrocarbons. These factors are the thickness of the seal and its lateral extent, as well as the continuity of the seal.

Identification and evaluation of any top, bottom, and lateral seals must take place in the process of assessing any oil or/and gas accumulation. On a theoretical level, the thickness of the seals is not an adequate factor, as far as the sealing capacity is concerned. Though in any case, a seal with great thickness levels up the probability of having a profitable exploitation project, because a continuous sealing surface consisting of many layers is more than good for the effectiveness of an oil and gas trap. A seal would be considered adequate if consisted of shale, layered over 50 m thick, or, if consisted of evaporite, layered over 10 m thick, while a 30 m thick evaporite – layered seal would be considered excellent.

The most crucial factor when it comes to a seal's quality is the continuity of the layers, while the measured seal's capacity is of lesser importance. Under given pressure and temperature it is possible to measure the displacement or, entry pressure needed to force a hydrocarbon compound through a sample of rock. Nevertheless, it is difficult to reach a reliable prediction of the whole seal surface area characteristics by testing on a typical (4-8 in. diameter) core to reach quantitative results. The lack of reliability between the testing of a core and the characterization of a whole geological model is what drives scientists to focus on, the more likely, weakest points of the seal, throughout its entirety.

Half of the largest oil and gas fields of the world are trapped because of evaporite structures, although evaporites their selves are less than 2% of earth's sedimentary rocks. The other 50% consists of shale – sealed hydrocarbon fields (Figure 2-10). In 1981, Evans and Kirkland argued that 50% of the global, at that time, known, oil reserves within carbonates are located below evaporite formations. As far as it concerns the 25 greatest gas fields of the globe, nine of which are enclosed by evaporites while the other sixteen are enclosed by hydrates and shales. The most remarkable example that proves the unquestionable ability of evaporites to consist of an effective hydrocarbon seal is Gwawar, the worldly largest oil field, located in the Middle East. There the seal consists of bedded evaporites and anhydrite. The remaining reserves of Gwawar are estimated to be, approximately, more than 100-200 billion barrels, (Warren, 2006).

Hydrocarbon reservoirs and traps associated with evaporites cannot easily be classified into the typical categories of traps, i.e. structural, stratigraphic and diagenetic. This is because the salt is considerably mobile and soluble, and hence prone to diagenetic activity. Warren (2006) provides a rather simple classification of hydrocarbon reservoirs and traps associated with evaporites, bedded or halokinetic which is based on the simple question: “Where is the salt?”. This classification is presented in Table 2-1.

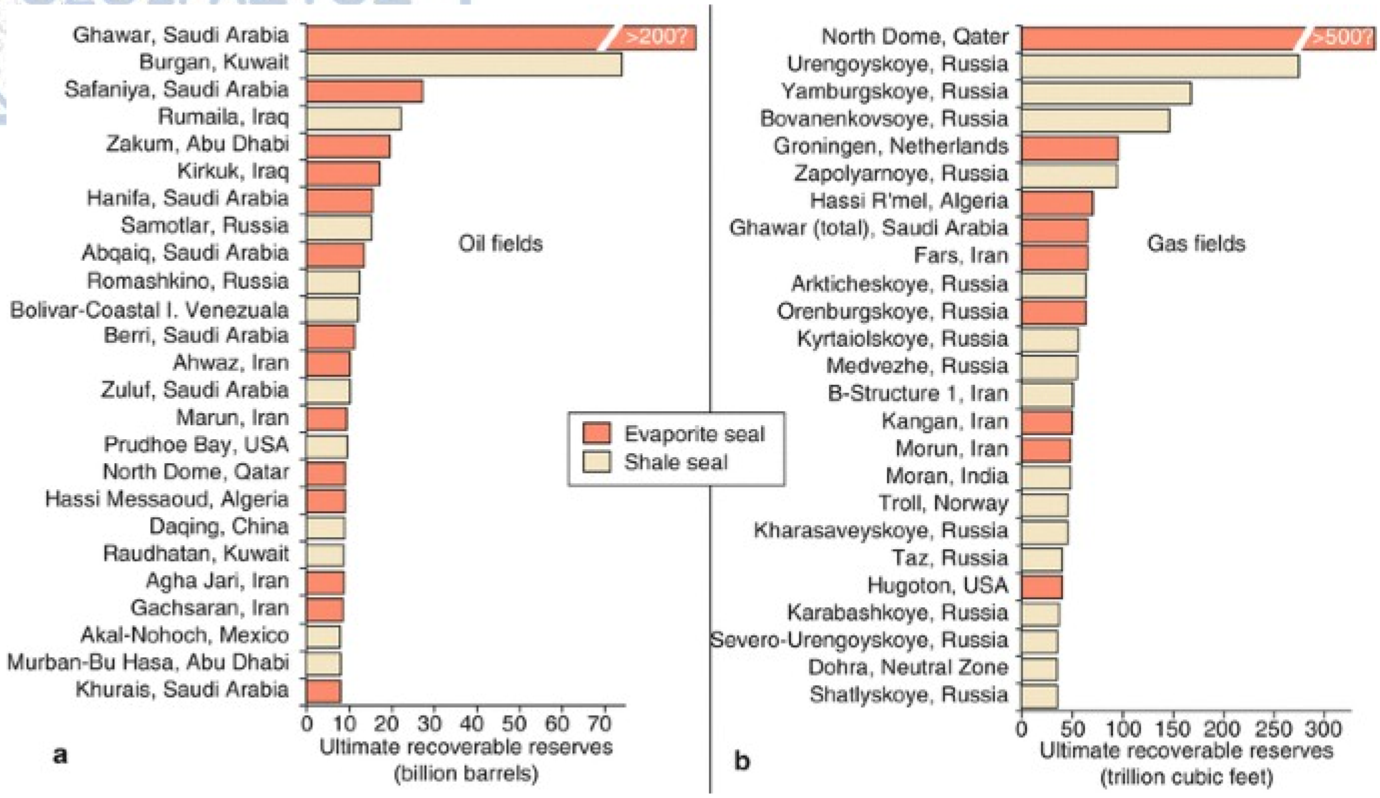

Figure 2-10. Recoverable reserves in the biggest hydrocarbon fields by type of seal - in part after Grunau, 1987 (Warren, 2006)

Based on the classification of Table 2-1, hydrocarbon reservoirs can lie in three possible positions relative to evaporites: above (suprasalt), within (intrasalt), and below them (subsalt) (Figure 2-11). In some cases, a hydrocarbon reservoir can lie in more than one position. Nevertheless, the deposition process, the diagenetic procedures, as well as the structural evolution, control the position of a reservoir and the associated seal, as shown in Figure 2-11.

		Effect of evaporite on nearby reservoir		Effect of seal itself	
		Depositional	Subsurface/diagenetic	Depositional	Subsurface/diagenetic
Bedded salt	Suprasalt	Presence of brine, either from salt dissolution or deposition of nearby salt can prevent accumulation of carbonates or siliciclastics containing a normal marine biota.	Solution of bedded salt creates collapse sinks and fronts that can enhance deposition of porous sediments or encourage collapse fracturing in overlying beds	Not applicable	Dissolution of salt creates a dense brine plume that aids in the formation of hydrodynamic traps
	Intrasalt		Solution of surrounding salt creates fractured and brecciated intrasalt beds that can stack into porous solution breccias	Not applicable	Permeable intervals are encased in bedded salt
	Subsalt	Evaporite bed acts as a source of Mg-rich brine that improves permeability of underlying or adjacent bed (creation of mouldic porosity and brine reflux dolomite)		Evaporite bed acts as top seal and/or lateral seal to reservoir (well documented)	Evaporite bed acts as a source of saturated brine for cement plugging of underlying or adjacent unit
Halokinetic	Suprasalt	Shallow halokinetic salt focuses the deposition of porous sediment around areas of uplifted seafloor or land surface. Can also influence the formation of slumps and CCD-related sedimentation	Dissolution of the upper salt surface creates a caprock reservoir	Salt flows carries blocks of anhydrite/dolomite and allochthon dissolution creates salt ablation (retreat) breccias	Passage of salt allochthon creates adjacent zones of alteration/cementation that may continue to act as a barrier to fluid flow even when the salt is no longer present (weld)
	Intrasalt	Not applicable	Salt flow can break up, fracture and rotate organic-rich intrasalt beds, allowing them to become self-sourcing reservoirs encased in a halokinetic salt seal	Brecciation of intrasalt bed leads to overpressurred blocks within the salt mass	Salt flow allows salt unit to maintain seal integrity
	Subsalt	Not applicable	Brine plume created on the underside of a dissolving salt allochthon can alter underlying beds, which in some situations (eg fluid breakthrough) can enhance permeability of underlying beds via dolomitisation/fracturing	Salt allochthon acts as top seal or lateral seal to reservoir sands (well documented). The ability of salt to maintain seal integrity under both extension and compression is significant	Passage of salt allochthon creates adjacent zones of alteration/cementation that may continue to act as a barrier to fluid flow even when the salt is no longer present (weld)

Table 2-1. Classification of hydrocarbon reservoirs and traps by Warren, 2006.

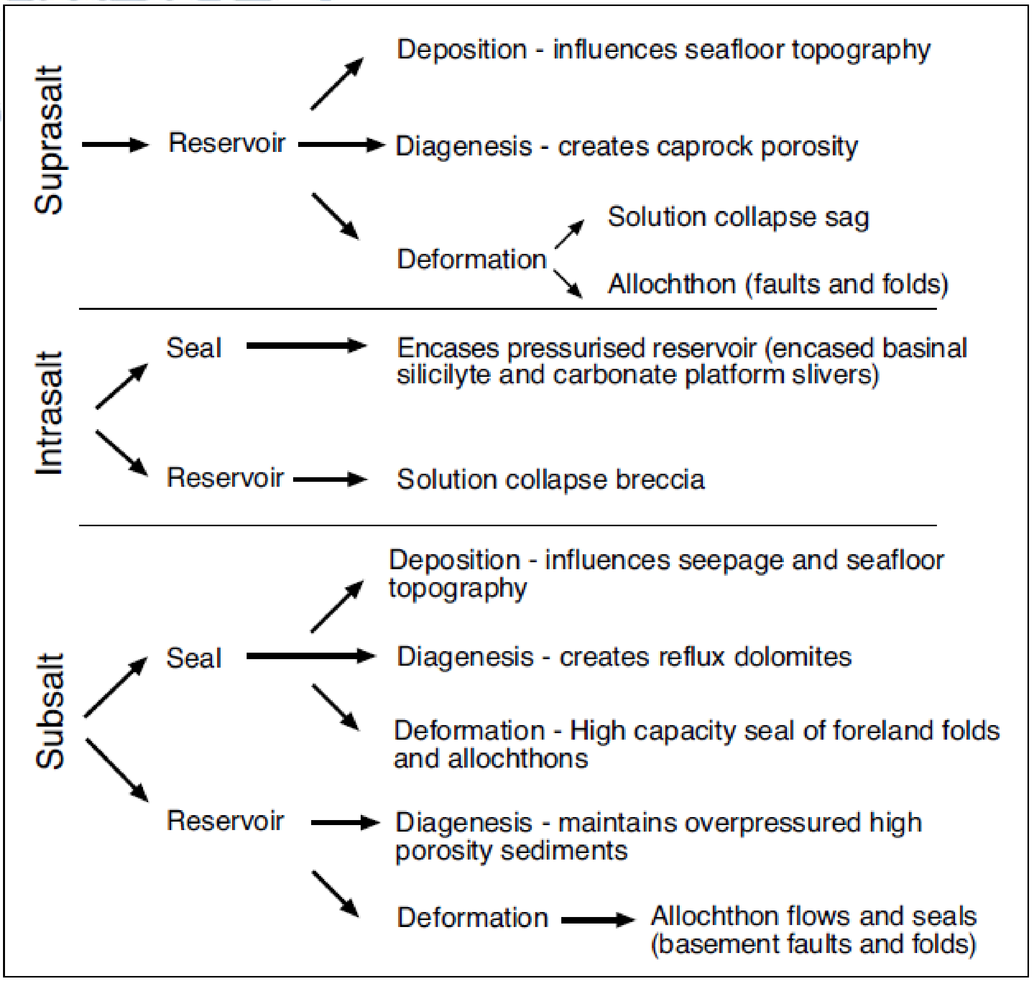

Figure 2-11. Classification of evaporitic seals and associated hydrocarbon accumulations to the seat of the accumulation and the effective geological procedures by Warren, 2006

2.3 Salt structures and salt tectonics

Many archaic, massive, and extensive evaporitic salt deposits, lying under siliciclastic and carbonate sediments, present particularly irregular geometries, such as diapirs, walls, pillows, or isolated bodies (Figure 2-12). These structures are called "salt structures", and the mechanism that causes them is called "salt tectonics", "halokinesis" or "halotectonics". The general perception of the initial salt deposits is that they had a relatively uniform thickness and rather horizontal bedding (Jackson & Talbot, 1991). So, salt tectonics examines the shapes and the processes involved in the evolution of evaporite layers of significant thickness containing rock salt within a stratigraphic sequence of rocks. This is due both to the low density of salt, which does not increase with burial, and its low strength.

Salt structures (excluding undeformed layers of salt) have been found in more than 120 sedimentary basins across the world (Wikipedia, 2021).

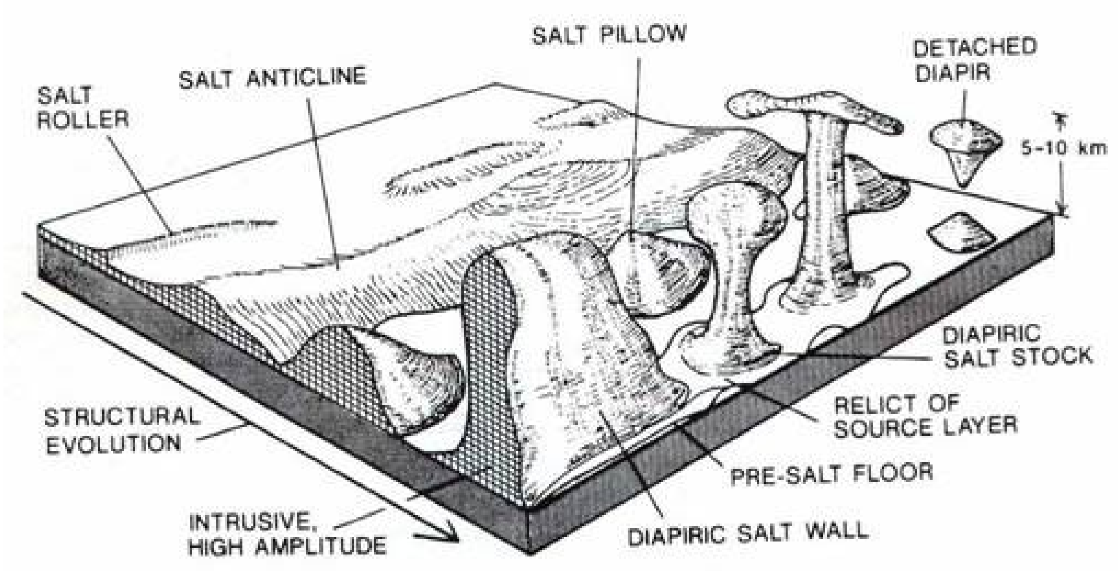

Figure 2-12: Basic types of salt systems and their structural transformation, (left to right) (Einsele, 2000) (Jackson & Talbot, 1991)

Salt structures result from both non-tectonic and tectonic processes. Non-tectonic processes refer to the behavior of salts under a load of overlying formations of different thicknesses and densities (***passive salt structures***). Tectonic processes greatly modify the non-tectonic structures of the salts (***active salt structures***). As will be discussed in more detail below, such tectonic processes include, for example, the faults in underlying rocks, expansion or merging of sedimentary piles containing salts, or over thrusting of stratigraphic layers containing salts during orogenetic processes (Einsele, 2000).

Salt domes and other salt systems are related to the effect of buoyancy. In sites where lower-density salts are lying under higher-density formations, they tend to flow upwards through the overlying formations (***buoyancy halokinesis***). In this case, the depth at which salts are lying should be at a minimum of 900m and up to 1200m. In any other case, the overlying rocks do not reach a density that is high enough for this process.

Apart from buoyancy, there are also certain overburden anomalies (***halokinesis due to differential loading***), which can cause salt sinks and the growth of salt domes (Ge, Jackson, & Vendeville, 1997). This process does not directly rest on the density of the overlying sedimentary layers and thus can be induced at shallower burial depths (up to 100m). The combined action of both processes, buoyancy and differential loading, as well as the effect of expanding fractures on facilitating the rise of salts, is summarized in the following paragraphs for the most significant type of salt deposits, which are the rock salts.

2.3.1 Salt flow mechanisms – Halokinesis of rock salts - Diapirism

Rock salts behave either as Newtonian or as viscoelastic fluids. They behave as viscoelastic fluids only when the differential pressure or stress is greater than the salt's yield point and salt flow does occur. When salt flow occurs, salt always moves from the area with the highest hydraulic head to the area with the lowest hydraulic head, or in the direction of the biggest hydraulic gradient (Figure 2-13A).

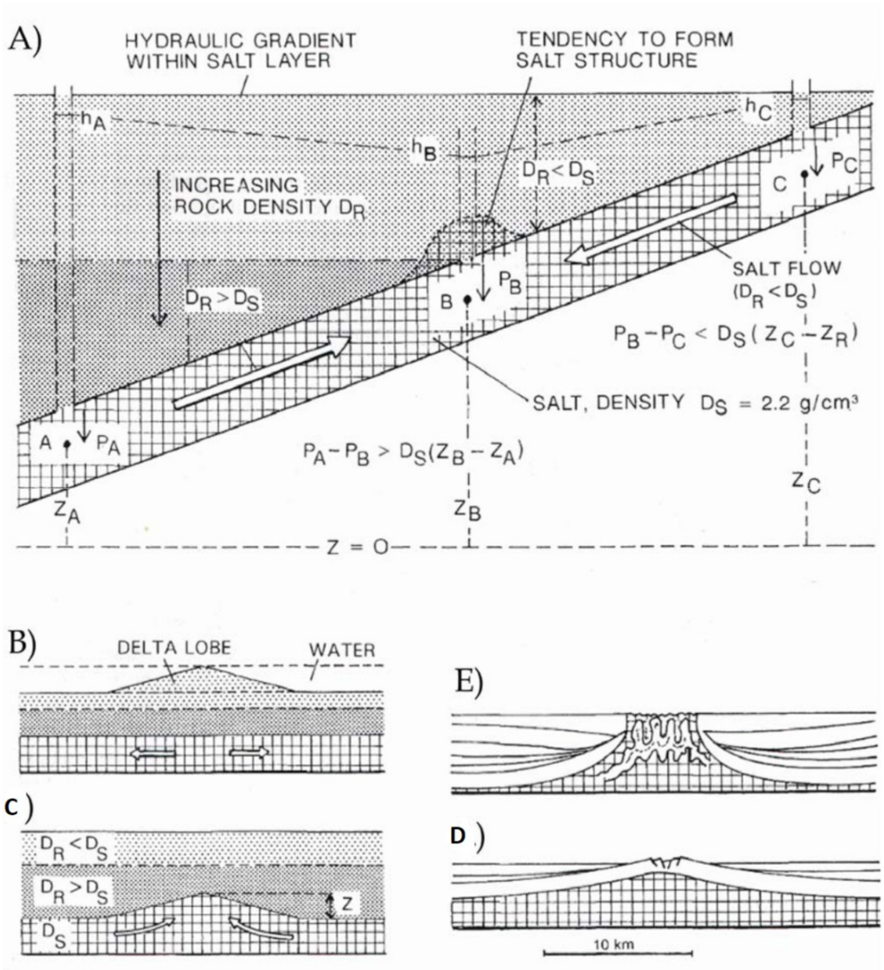

Figure 2-13.Underground salt flow to the hydraulic gradient within the salt layer. A) Salt flow upwards and downwards depending on the lower or higher density, D_R, of sedimentary rocks above the sloping salt stratum with density D_S. At point B the combined salt flow frequently forms a salt structure. B) Differential loading of a horizontal layer of salt, e.g. from a protruding turbidite pod, brings about the flow of salt away from the region of the highest loading. C) The presence of an anomaly on the surface of the salt layer causes the salt to flow into the anomaly, in case $D_R > D_S$, within depth zone Z. Otherwise ($D_R < D_S$) the salt flows away from the a. D) & E) Two growth phases of a salt dome. D) Formation of salt pillow and onset of erosional truncation. E) Extrusion of salt through overlying formations. There is a strong folding of the primary salt layers. These figures do not show the subsequent collapse and burial of the salts (Kehle, 1988)

The difference in hydraulic head between two points within a salt layer is the hydraulic gradient. The hydraulic pressure at any point in the fluid is the sum of its gravitational potential (G), at an altitude Z (measured above a reference level), and the fluid pressure (P) at that point, which is the height of the fluid column in a manometer at that point (USGS, 2013).

A sloping layer of salt can flow upwards if the pressure drop, ΔP (P_A-P_B in Figure 2-13A), is higher than the rise in gravitational potential, ΔG, as it is defined from the difference in altitude between two points and the density of the fluid, that is $\Delta G = Z_B * D_S - Z_A * D_S$ (where D_S is the salt density).

That is, according to Figure 2-13A:

$$P_A - P_B > D_S (Z_B - Z_A)$$

The phenomenon described here takes place when the average density of the overlying rocks, D_R, is higher than the average density of the evaporitic salt. Otherwise, the salt flows downwards (from point C to B, Figure 2-13A). Therefore, the mechanics of salt flow is determined only by the pressure gradient and the gravitational potential and not by the load of the overburden. Nevertheless, to initiate the viscoelastic salt to flow its yield point must be exceeded for the flow to begin.

A horizontal salt layer covered by horizontal and laterally uniform newer sediments present a hydraulic gradient that equals the gravity potential gradient because the weight of the overlying formations is everywhere the same. Thereafter, no salt flow takes place. Nonetheless, if the surface of the salt layer locally rises (anomaly height Z, Figure 2-13C), then there will be an increase in the hydraulic head. If the density of the overburden in the range of the anomaly is higher than the salt's, then the salt flows towards the anomaly. When the overburden has a lower density than that of the salt, then the salt flows away from the anomaly. (Warren, 2016)

Similarly, a local increase in the pressure of the overlying formations (differential loading), can create a significant hydraulic gradient in the salt stratum, hence forcing the salt to flow away (Figure 2-13B). Other load anomalies in sedimentary formations that can trigger underlying salt rocks to flow in the subsurface are reefs, desert dunes, etc.

Specifically, a sedimentary layer that progrades above a layer of evaporites creates lateral forces that trigger salt flow. This process happens similarly to when we press the toothpaste tube vertically and the toothpaste flows laterally. The resulting precipitate causes the flow regardless of the density of both the evaporative layer and the sediment itself. Also, the formation of salt structures is associated with the presence or absence of discontinuities in the evaporitic layer. (Scheffler, et al., 2019)

Progradation is an important triggering mechanism for salt halokinesis, diapirism, and formation of allochthonous structures. A salt body pushing through its overburden is known as diapirism. Figure 2-14 shows the final form of an initially horizontal salt layer overlying a flat-top basement in which lateral pressure was exerted by the progradation of overlying sediments. Though the salt is expelled basinward by the prograding wedges, extensive salt structures are not observed in this image. However, active tectonics increases the likelihood of the development of salt structures, as in Figure 2-14 which shows the evolutionary stages of an initially horizontal salt bed that underlies a cracked formation and exerts lateral pressure upon it. In this image, it is observed that the salt, at the point where there is a crack, creates an anticline that gradually evolves into a scattered and non-native structure of salt. Figures 2-14 and 2-15 are the results of experiments on scaled physical models.

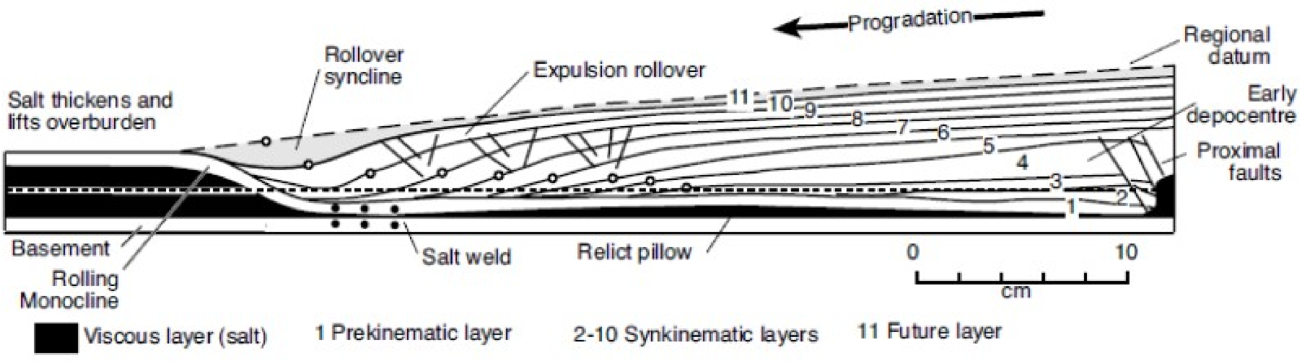

Figure 2-14: Section showing the structures formed by an initially horizontal salt layer overlying a flat-topped basement, under lateral pressure exerted by the progradation of overlying sediment. The dashed line represents the top of the initially horizontal salt layer (Warren, 1999)

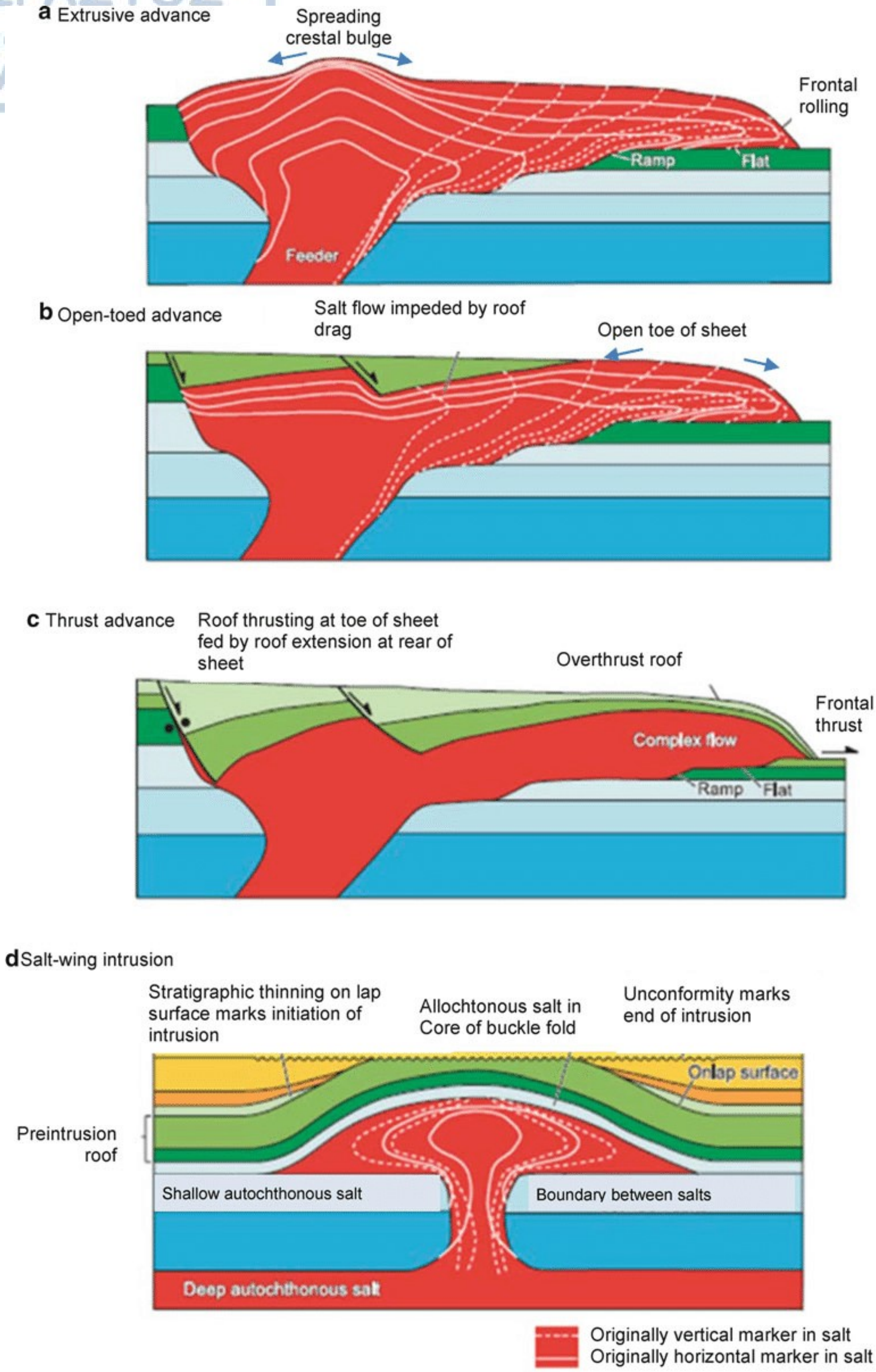

Figure 2-15: Four types of salt structure evolution. An initially flat salt is underlying a cracked formation deformed under later forces exerted by the emergence of overlying newer sediments (Kennicutt, 2017)

Diapirism due to expansion holds an important role in the mechanisms of the generation of salt structures. Under the expansion mode, the upper margins penetrate the overburden in three ways: Reactively, actively and passively (Figure 2-16). A reactive diapir penetrates the overlying formations during the creation of expansion cracks, by filling the gaps created between the ruptured pieces of rock. In this case, the creation of faults is not due to the rise of the continent, but to the tectonic regime that acted earlier. Therefore, it requires regional extensional faulting caused by rifting or by thin-skinned gravity spreading or gliding, which creates the necessary space for this type of diapir. Reactive diapirism is a capable mechanism for initiating the evolution of salt structures, regardless of the thickness, the lithology, and the density of the overlying formation. (Jackson, Vendeville, & Schutz-Ela, 1994)

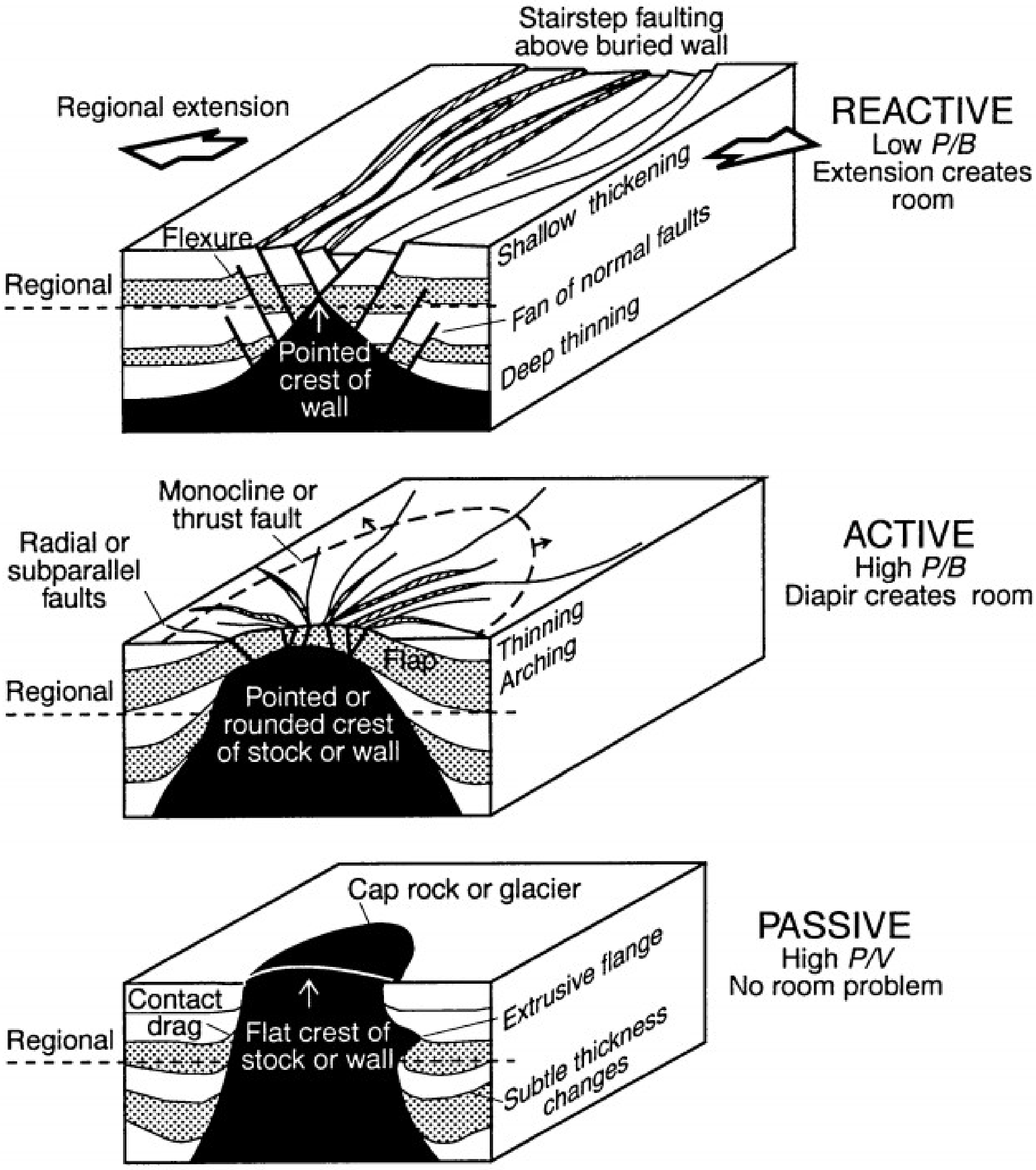

Figure 2-16:Three models of diapir extrusion (in black color) and their characteristic structures. The regional line (dotted line) is the base of the upper dotted layer. P, V, and B refer to stresses due to pressure, viscosity of the salt layer, and brittle strength of the overburden, respectively(Warren, 1999)(Jackson, Vendeville, & Schutz-Ela, 1994).

The active diapir raises and pushes its overburden laterally. This is only possible when the overlying formations are relatively thin and the salt pressure is greater than the overburden's brittle strength. Regardless of the force that drives the rise of the diapir (density inversion, crystallization forces, lateral contraction), the active diapir pierces forcefully the overlying formations, thereby solving the room problem. (Jackson, Vendeville, & Schutz-Ela, 1994)

When a diapir arises and flows onto the surface then it turns into a passive diapir. As the crest of the diapir becomes taller, its top remains at or near the surface, while the sediments next to the diapir top sink, together with the source salt layer (down-building). A passive diapir cannot continue to emerge without continuing sedimentation to load areas next to the top of the diapir at or near the surface, but the salt base can enlarge and if expansion continues the salt base will finally sink (falling diapir stage). The top of the diapir is covered by a thin skin of sediments, which are constantly eroding. Its remains are carried away from the diapir crest by a diverse sideways flow of the underlying salt. There is little or no sediment gathered onto the crest of a passive diapir. This translates into the absence of vertical pressures that would prevent the diapir from spreading. Cracks and folds in the sediments around a passive diapir are limited. (Warren, 2016)

2.3.2 Evolution of salt structures

The structures of salts are very diverse because they depend on many parameters, such as the location of the structures within the basin, the initial salt layer thickness, the history of the basin subsidence, and the sediment accumulation history.

A very common salt dome is usually one to several kilometers in diameter and its sides may present very steep dipping or they even may overhang to an extend of several kilometers downwards. The individual stages of their evolution are the following (Kennicutt, 2017):

1. Initiation and formation of salt pillows
2. Truncation of the overburden through erosion
3. Piercement of salt domes or extrusion of salt pillars through paths created by the erosion of the overlying sediments.
4. Collapse and burial

During the extrusion of any salt structure through the eroded overburden enough salt is lost due to erosion and dissolution which occur both on land and below the sea. Once the initial layer of salt that feeds the structure is exhausted, then the rise of the salt stops. At that time the salt structure can attain a rather steady-state in the vertical dimension, regardless if the structure is covered by ever-increasing sediments or not. Nevertheless, the lateral spreading of the salt may go on. The internal structure of many domes is marked with compact folds and greatly deformed and diverse salt bodies. (Einsele, 2000)

The relation between the formation of a salt dome and the thickness of the initial salt layer (primary salt) is shown in Figure 2-17A-B, where the processes which take place after deposition above the salt wedges are displayed. Thin salt layers can only create low-in-height pillows. Tectonic expansion structures (extensional faults and grabens) are usually formed on the top of larger salt structures (both pillows and domes), as well as on the top of salt anticlines with highly steeping slopes. In the zones between two successive salt structures, where the initial salt layer has receded, synclines (depocenters) develop, where newer sediments accumulate (Figure 2-17B-D). The layers along the sides of the salt structures often appear inverted.

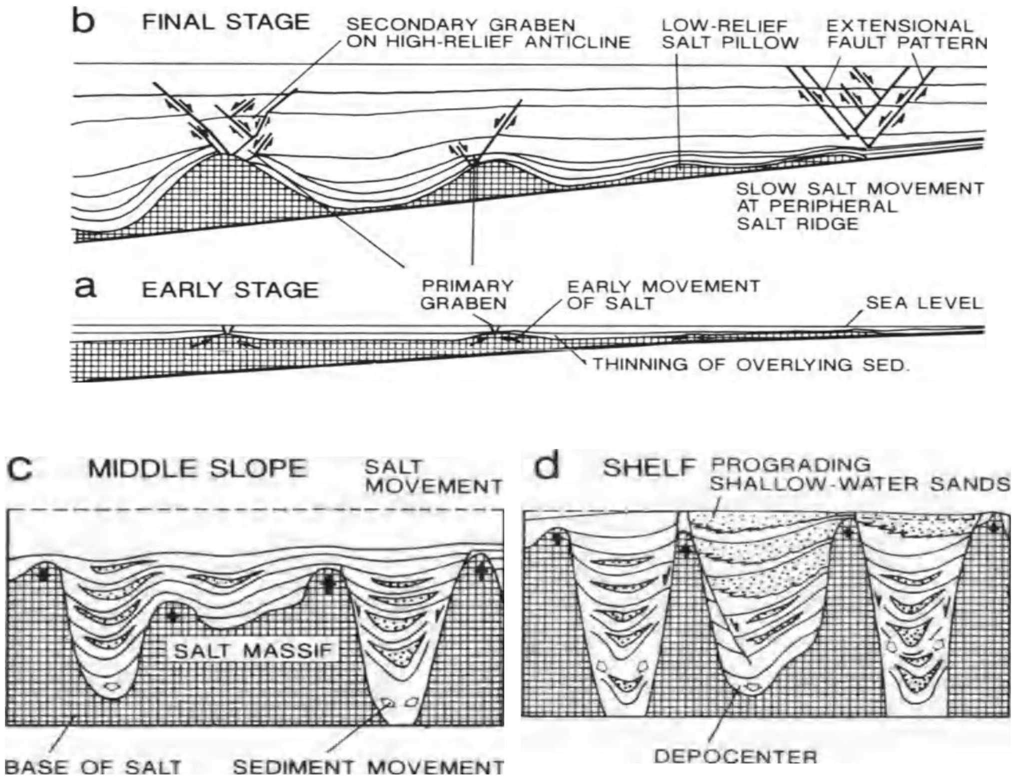

Figure 2-17: Different salt structures. A), B) Evolution of pillows and anticlines from evaporite wedges with a thickness increase towards the center of the basin (Kehle, 1988). C), D) Development of synclines (depocenters) between salt diapirs derived from massive salt layers in a continental environment (slope or shelf). The movements of salt as well as of newer sediments start on the lower part of the slope and are intensified due to the increasing accumulation of sediments coming from the prograding edge of the continental shelf. Sand deposits may form oil & gas reservoirs (Einsele, 2000)

The two examples in Figure 2-18 show some of the more complex salt structures, including wedges of salt thrusted over newer sediments and allochthonous salt canopies (away from the source layer). The process of their formation is considered to have taken place at shallow depths, where the density differences between salt and sediments are low.

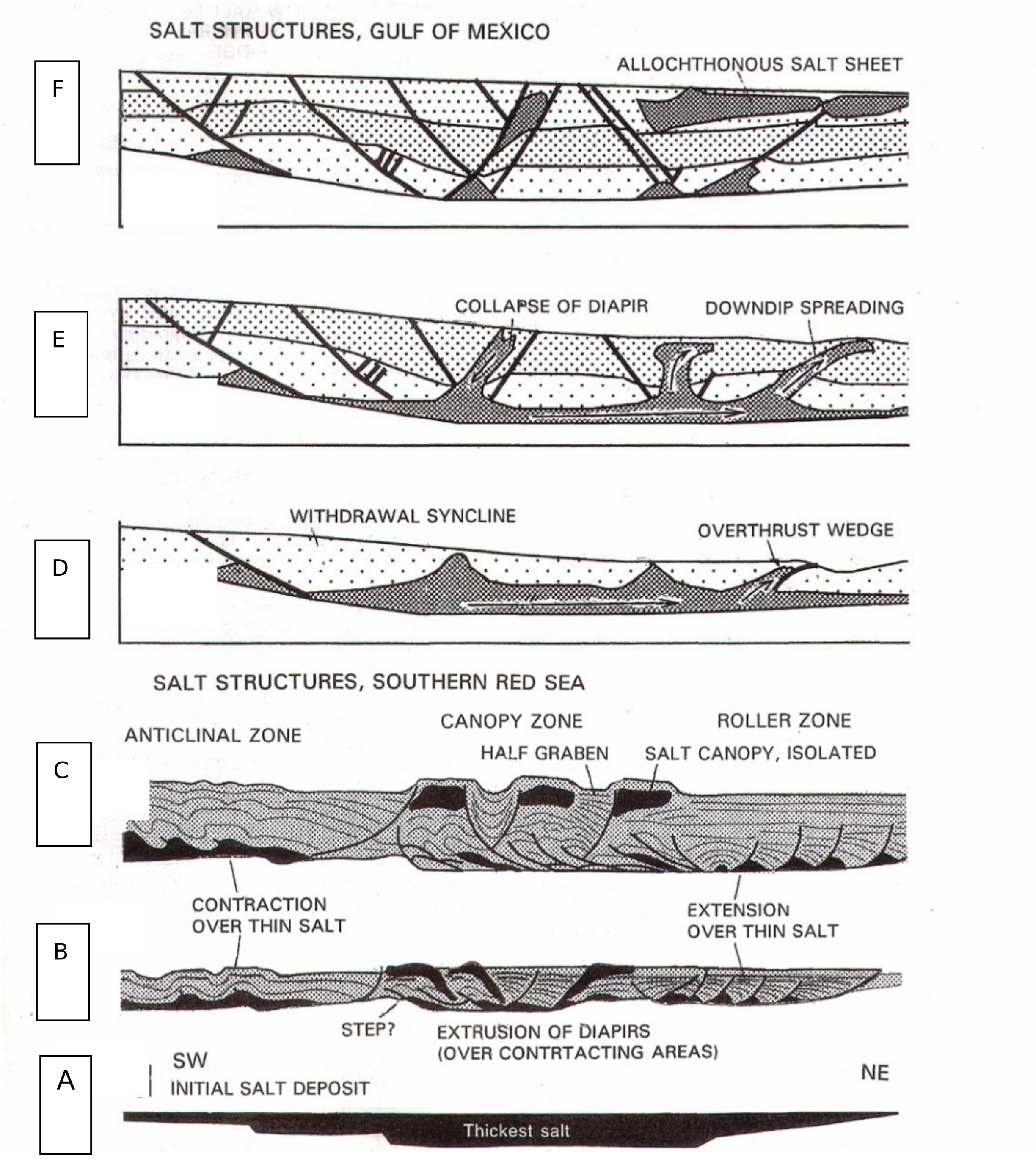

Figure 2-18: A), B), C) Formation of allochthonous salt canopies from diapirs and salt wedges thrusted over newer layers. Salt canopies may eventually be isolated due to downdip gravitational spreading over younger sediments. The withdrawal of salt from the source evaporitic layer creates a dense system of thin-skinned faults, synclines, and grabens (see also F). D), E), F) Various salt structures in the Southern part of the Red Sea, restrained by the thin-skinned tectonic regime above the initial evaporitic layer, i.e. extension over a thin or thick evaporitic layer and contraction. The canopy zone grows over a thick layer of primary salt (Einsele, 2000)

Because anhydrous evaporites present low shear strength, in many cases, they serve as slip surfaces on which the newer layers move downwards at very low angles. Such a case is shown in Figure 2-18D-F, where along one end of the former salt basin extensional structures appear (where salt rollers are present), while along the opposite end of the basin, compressional structures occur (salt anticlines), which act as a form of a backstop. The zone of massive primary salt deposition certainly in the basin is influenced by diapirism and in parts by recession. The salt diapirs emerged to the surface, were subjected to leaching and, in the end, they were separated from the source layer of salt and covered by newer sediments. Thus, the allochthonous salt (canopies) appear at shallow depths underneath the mudline (Einsele, 2000).

CHAPTER 3. PROPERTIES AND BEHAVIOR OF SALT FORMATIONS

3.1 Introduction

In this chapter, the main evaporite minerals will be examined along with their physical properties, while emphasis will be put on their logging and mechanical properties. In addition to that, their behavior when it comes to salt formations will be analyzed, followed by the most important geomechanical considerations. A summary of the geomechanical hazards related to salt formations will also be examined. It should be noted that all of which is referred to above, will be reported in relevance with the drilling procedure.

As previously stated in paragraph 2.1, salt is related to many extended oil and gas reservoirs around the world, in places such as the GoM, the southern parts of the North Sea, offshore Brazil and Angola, Canada's sedimentary basins or, Egypt, Iran and the Middle East, as well as Kazakhstan. These oil and gas reservoirs involve drilling through salt that sometimes has a thickness of approximately 1500-2500 m, and is located even in depths of 5-9 km below the earth's surface (Figure 3-1). (Dusseault, Maury, Sanfilippo, & Santarelli, 2004) (Wilson & Fredrich, 2005).

3.2 Main evaporite minerals

Evaporite formations do not necessarily contain only halite (NaCl), although halite formations (rock salt) are well known to form salt domes (diapirs) and traps for hydrocarbon accumulations. In reality, marine evaporite formations present mineral sequences indicating cyclic conditions and mineralogy decided by solubility. Table 3-1 presents the most common minerals of marine evaporite formations

Anhydrite and halite are the most significant minerals, and secondarily gypsum. Evaporite minerals form in the following order: calcite, gypsum, anhydrite, halite, polyhalite, and finally potassium and magnesium salts including sylvite, carnallite, kainite, and kieserite. The physical and chemical parameters for evaporite minerals are well known since their sequences have been replicated in lab studies.

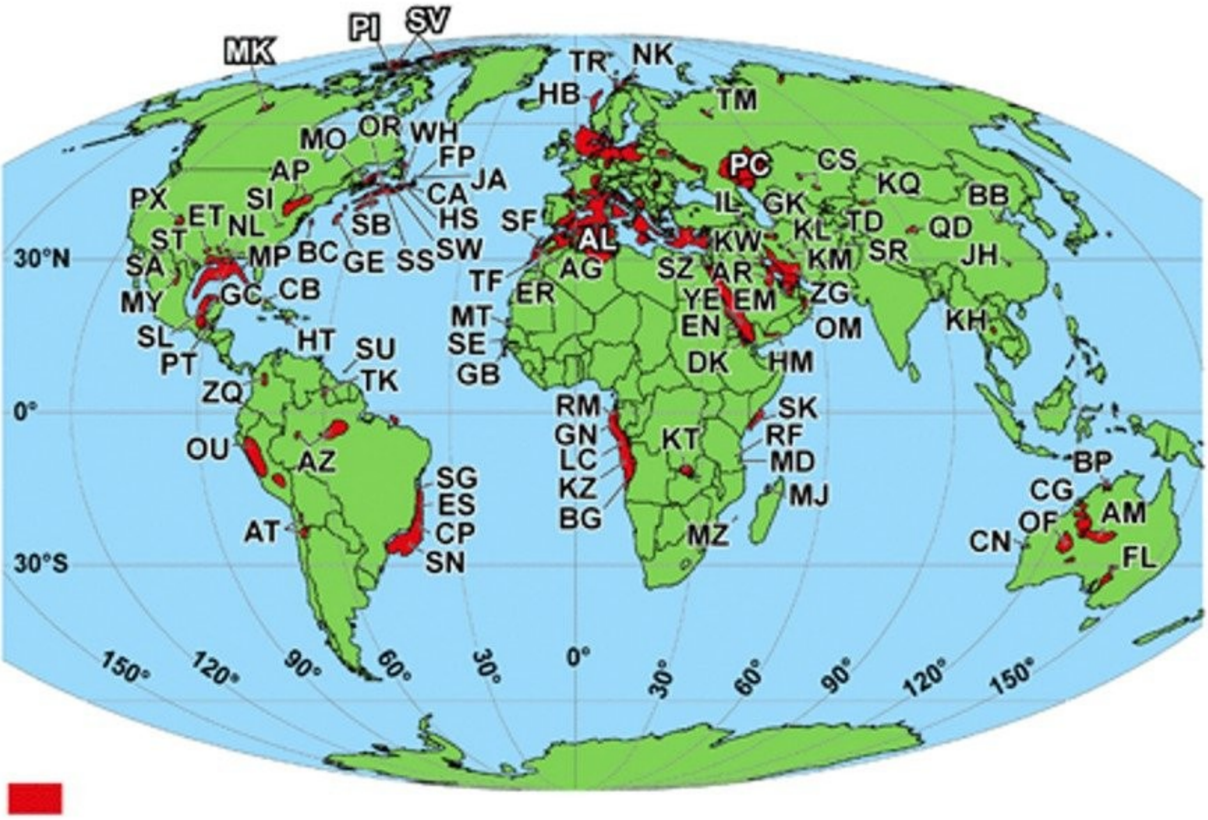

Figure 3-1. Salt basins around the world. Many salt basins comprise some of the most productive and prospective oil and gas provinces. © Martin Jackson, University of Texas at Austin (https://www.geoexpro.com/articles/2008/05/salt-s-effects-on-petroleum-systems)

Table 3-1. Main minerals of marine evaporite formations

Group	Mineral	Formula
Chlorides	Halite	$NaCl$
	Sylvite	KCl
	Carnallite	$KMgCl_3 \cdot 6H_2O$
	Kainite	$KMg(SO_4)Cl \cdot 3H_2O$
Sulfates	Anhydrite	$CaSO_4$
	Gypsum	$CaSO_4 \cdot 2H_2O$
	Kieserite	$MgSO_4 \cdot 2H_2O$
	Polyhalite	$K_2Ca_2Mg(SO_4)_6 \cdot H_2O$
Carbonates	Dolomite	$CaMg(CO_3)_2$
	Calcite	$CaCO_3$
	Magnesite	$MgCO_3$

Before proceeding to the properties of halite, anhydrite and gypsum are crucial to talk about the composition of salt domes and bedded evaporites. Salt cores from German domes consist of sylvite, halite, and some other potash minerals laid alternately. These layers present folds that are vertically placed and get more complex at the outer edges of the dome. When it can be determined how old the central strata in German domes are, first-formed materials are typically found centrally in the dome and later-formed materials on the periphery. Cores from Iranian salt domes consist of halite, mixed with marl (argillaceous limestone), anhydrite, and big blocks of igneous rocks and limestone. In Caspian salt domes, the central mineral grains are vertical, whereas those at its periphery are horizontal.

Examining cores of several salt domes on the North American Coast, they contain mainly halite (sodium chloride), with small amounts of anhydrite (calcium sulfate) while other minerals may appear in traces. White and black halite layers are alternately interbedded with layers of anhydrite. Halite grains cores from the Gulf Coast salt domes, show a complicated pattern of orientation not only horizontally, but vertically also.

Where salt constitutes the cap rock, it usually consists of anhydrite and limestone, with a thickness of up to 300m, typically of about 100m. In many instances, as in salt domes along the Gulf Coast, the cap rock can be separated into three more or less horizontal zones, that are characterized as irregular and gradational: an upper zone consisting of calcite, a transitional zone in the middle that is identified by the presence of gypsum and sulfur, and on the base a zone consisting of anhydrite. Most scientists agree that cap rocks were formed when salt from the salt core's surface dissolves, leaving behind an insoluble anhydrite residue that eventually changes into gypsum, calcite, and sulfur. The researchers presume that the solution occurs in the shallow water zone and domes at great depth with cap rock that must have formerly been near the surface before becoming buried.

Another feature in the Gulf Coast salt domes is the presence of shale. It may take the form of a sheath that entirely envelops the salt or it may only cover the bottom regions of the salt. It occurs more frequently on salt domes that are deeply buried or on salt domes whose summits are close to the surface. The bedding planes of shale are deformed because in the shale the pore pressure is substantially higher than that of the surrounding formations. Fossils in the shale act as indicators, proving that shale comes from an older, thus deeper layer since are older than those of the nearby strata. (Britannica, 2019)

3.2.1 Physical properties of evaporite minerals

3.2.1.1 Halite

Halite (rock salt) is NaCl (sodium chloride). Salt mainly gets crystallized in cubic or octahedral-shaped crystals. It is formed when seawater containing sodium chloride evaporites. Its composition is monomineralic, yet finding in nature pure salt is more than rare. Usually, we meet halite containing portions of sulfates, clay, or potassium and magnesium chlorides and organic matter. When it comes to recently deposited halite, its porosity can be between 10 to 20%, or even more. Its hardness is about 2 to 2.5 on the Mohs scale, while its specific gravity is around 2.10 to 2.40 g/cm^3. Regarding S-wave velocity, it reaches up to 2630m/^{2} while P-wave velocity is up to 4550 m/s according to Crain (2003). According to Wzersky et al. (2006), P-wave velocity in the Dead Sea's salt reaches 2900 to 4250 m/s. Moreover, in salt domes, halite's P-wave velocity may rise to 6000 m/s. As far as concerns the solubility of salt, in normal meteoric water and at a given temperature of 25°C, is 360 g/L, making salt very soluble, while according to Raeisi et al. (2013), its water conductivity, measured in a sample in Iran, varies from 2400 to 400,000 μS/cm.

Halite is incompressible and flows like a fluid or plastic. It is mechanically weak, and thus moves only if the resistance to flow doesn't exceed the driving forces (Hudec & Jackson, 2007). It can be met in single or not, thin laminae, as interbeds or veneers of different thicknesses, but also as compact deposits of massive volume. Salt may also occur redeposited in joints. Fossil rock halite doesn't consist of open pores or voids and acts like a plastic mass. A given deposit can be a few cm thick or even 1000m thick, as on the sea floor of the Mediterranean. Deeply buried halite is thermally expanded so it recrystallizes or dissolutes, while its density decreases (Figure 3-2a).

Salt usually forms diapiric masses which, plastic move upwards episodically and slowly, while deforming or piercing overlying strata. GoM diapirs upward movement is approximately 0.1 to 1 mm/annum. The most rapidly extruding diapir is located in Iran (Zagros Mountains). The convergence of the Arabian and Eurasian tectonic plates is forcing the salt to move faster than usual. Other active salt structures, in Iran, are salt domes and "namakiers" (meaning salt glaciers or sheets flowing downslope plastically).

Some of the rarer minerals of salt are cainite ($MgSO_4 \cdot KCl \cdot 3H_2O$), carnallite ($MgCl_2 \cdot KCl \cdot 6H_2O$), thenardite ($Na_2SO_4$), shenite ($K_2SO_4 \cdot MgSO_4 \cdot 6H_2O$), mirabilite

($Na_2SO_4 \cdot 10H_2O$) or, glauberite [$NaCa(SO_4)_2$]. The most widely spread potassium salt in oil and gas fields is sylvite (KCl) with a solubility of 360 g/L and hardness of 1.5-2 on the Mohs scale (Milanović, Maksimovich, & Meshcheriakova, 2019).

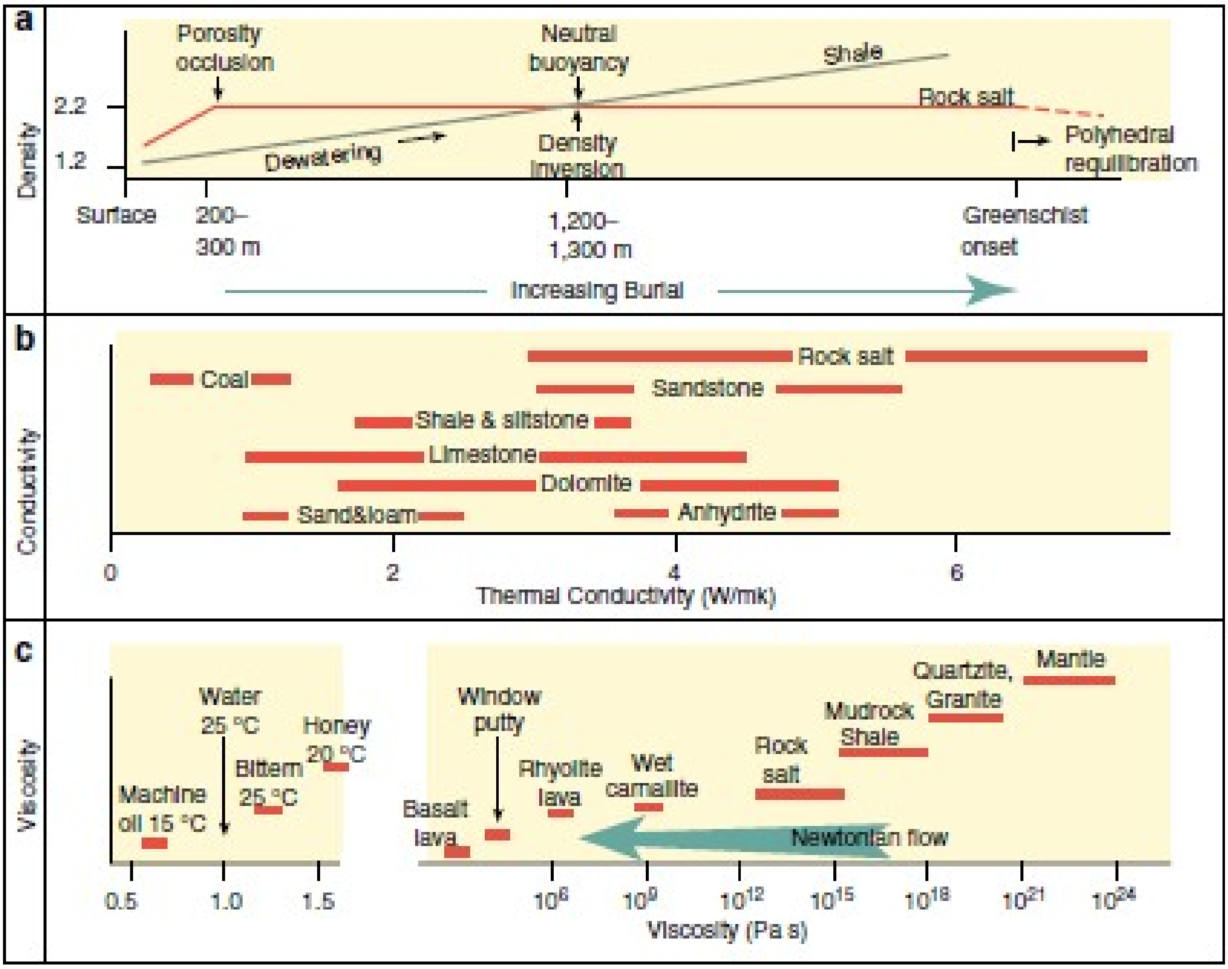

Figure 3-2: Physical properties comparison of rock salt to other lithologies. (a) Density changes with burial (b)Thermal conductivity (c) viscosity (Warren, 2016)

3.2.1.2 Anhydrite

Anhydrite ($CaSO_4$) is a sulfate that appears in compact or granular structures, as orthorhombic-shaped crystals. Its specific gravity is between 2.63 to 3 g/cm^3. Its solubility is 2.1 g/L while, its unconfined compressive strength varies between 40 to 123 MPa. Its hardness on the Mohs scale is 3 to 3.5. It is commonly the first evaporite mineral that is deposited in most salt structures and can be found also in claystones and marls as coalescences that occurred as a result of the reaction of sulfuric acid with the local carbonate minerals. Moreover, there are times when anhydrite is formed hydrothermally as one of the alteration products of Cu, Pb, or Zn mineralization (Milanović, Maksimovich, & Meshcheriakova, 2019).

3.2.1.3 Gypsum

Gypsum ($CaSO_4 \cdot 2H_2O$) is a hydrated calcium sulfate with monoclinic crystals with a specific gravity that comes between 2.3 to 2.37g/cm^3 and a hardness of 1.5 to 2 on the Mohs scale. Its unconfined compressive strength is 24 to 35MPa and its saturation concentration in normal meteoric water is 2.65 g/L. The water of gypsum is easily lost and regained when heated or cooled, respectively, while gypsum is a bad conductor of heat. The gypsum structures are crystalline to granular.

Gypsum formations can be deposited hydrothermally by precipitation in seawater of ionic oversaturated solutions. They can also be deposited in lagoonal settings or desert areas due to evaporation. Moreover, gypsum can be crystallized by the hydration of anhydrite or because of cold water solutions appearing in salt deposits.

Gypsum is chemically active in water and not stable at all because of ionic-type bond predomination. Their molecules are layered with the sulfate and calcium ions separated by H_2O molecules. The appearance of gypsum crystals usually is tabular and twinned while sometimes prismatic or columnar.

The viscosity of gypsum is significant while fracturing in this mineral is rough to brittle and often grainy. It should be noted that gypsum structures are classified into primary and secondary subdivisions. The ones created from the precipitation of the minerals from the initial solution are the primary. The partial or whole recrystallization of the primary or their replacement forms the secondary structures. Not only that but the textures of gypsum are classified into primary and secondary too, with the first ones to be created cause of sedimentation processes and the second ones created while the diagenesis procedure occurs (Milanović, Maksimovich, & Meshcheriakova, 2019).

3.3 Logging properties of evaporites

A collection of typical wireline logs can be used to determine a variety of evaporite parameters. Many evaporite beds have very little porosity, just a couple of dominating evaporite minerals, and no fluids free in the pores. In such cases logs interpretation is quite simplified and increases the validity of conclusions regarding mineralogy. Some scientists believe that log interpretations regarding evaporites are coming in handy for every hydrocarbon field with relevant cap rocks, regardless of the specific features of each field. The most common logs used in evaporites are the ones that measure hole diameter, electrical resistivity, and bulk density, as well as neutron porosity and acoustic logs. If potash salts exist to a considerable degree, also gamma logs may be used too (Warren, 2018).

It should be noted that MWD (measuring while drilling) and LWD (logging while drilling) equipment are currently being used to capture an alike collection of typical well log measurements in more and more drilling operations.

3.3.1 Electrical resistivity or electrical conductivity logs

The value with which formations oppose or not to the flows of electrical currents is known as electrical resistivity or electrical conductivity, respectively. A resistivity log is measuring the resistivity of a rock and its containing fluids combined. The majority of rock materials are insulators, whereas the fluids inside them are conductors. However, since hydrocarbons are the exception to fluid conductivity and are indefinitely resistive, they can be identified through the application of Archies' Law in order to calculate the degree of water saturation in potential resources.

When an evaporite needs to be identified, its negligible porosity is taken into account, because that is what it is different comparing to other non-evaporitic rocks and this fact is reflected in their high resistivity measurements (Table 3-2). However, an enhanced resistivity signature locally in a basin can later establish the existence of evaporite salts even though it cannot initially indicate their presence (Warren, 2018).

Table 3-2: Common logging properties of evaporitic salts along with accompanying brines and sediments (Warren, 2018)

		Composition	SG (gm/cc)	RHOB (gm/cc)	DT (µs/ft)	NPHI (lst ø equiv.)	GR (api)	Pe (barn/elect)	Resistivity (ohm.m)
Non-radiogenic	Anhydrite	$CaSO_4$	2.960	2.977	50	(-2)	0	5.05	10^4-10^{14}
	Gypsum	$CaSO_4.2H_2O$	2.320	2.351	52.5	49	0	3.99	1000
	Halite	NaCl	2.165	2.032	67	(-3)	0	4.65	>10^4-10^{10}
	Kieserite	$MgSO_4.H_2O$	2.57	2.59	na	43	0	1.8	
	Bischofite	$MgCl_2.6H_2O$	1.56	1.54	100	60+	0	2.6	
	Tachyhydrite	$CaMg_2Cl_6.12H_2O$	1.67	1.72	92	50+	0	3.82	
	Epsomite	$MgSO_4.7H_2O$	1.68	1.71	na	60+	0	1.2	
	Trona	$NaCO_3.NaHCO_3.2H_2O$	2.120	2.08	65	35	0	0.71	
	Sulphur	S_2	2.070	2.030	122	-3	0	5.40	
Radiogenic	Carnallite	$KCl.MgCl_2.6H_2O$	1.610	1.570	78	65	≈220	4.09	
	Sylvite	$KCl.MgCl_2.6H_2O$	1.984	1.863	74	(-3)	≈500	8.51	10^{14}-10^{15}
	Kainite	$MgSO_4.KCl.3H_2O$	2.130	2.120	na	45	≈245	3.50	
	Langbeinite	$K_2SO_4.2MgSO_4$	2.830	2.820	52	(-2)	≈290	3.56	
	Polyhalite	$K_2SO_4.MgSO_4.2CaSO_4.2H_2O$	2.030	2.790	57.5	15	180	4.32	
<u>Sedimentary minerals</u>									
Calcite		$CaCO_3$	2.710	2.71	49.7	0	0	5.08	
Dolomite		$CaMg(CO_3)_2$	2.870	2.88	43.5	4	0	3.14	
Quartz		SiO_2	2.654	2.64	52.9	-2	0	1.8	
Opal (3.5%H_2O)		$SiO_2.(H_2O)_{0.1209}$	2.15	2.13	58.0	2	0	1.8	
Barite		$BaSO_4$	4.5	4.09	na	-2	0	267	
Celesitite		$SrSO_4$	3.95	3.79	na	-1	0	55	
<u>Sedimentary rocks</u>									
Limestone (Ø=10%)			2.540	2.540	62	10	5 to 10	4.5	80-6000
Dolomite (Ø=10%)			2.680	2.683	58	13.5	10 to 20	3.09	8-6000
Sandstone (clean to dirty sst)			2.489	2.485	65.3	3	10 to 30	1.7-2.7	low-mod.
Shales			2.2 to 2.75		70 to 150	25-60	80-150	3.0-5.0	variable
Water at 32°C									
Fresh			1.000		200	100			
Saline 100,000 ppm NaCl			1.067		189	100			
Hypersaline 200,000 ppm NaCl			1.114		176	100			

<u>Legend:</u>
SG refers to specific gravity
RHOB refers to density log (response to generated radiation)
DT refers to sonic log (how much time it takes for sound waves to travel through rock)
NPHI refers to neutron porosity log (neutron bombardment)
GR refers to gamma ray log (natural or spontaneous radioactivity)
Pe refers to photoelectric index (response to an induced passage of current)

3.3.2 Total & spectral gamma-ray logs

The gamma logs are records of the radioactivity that a formation naturally emits. Specifically, a conventional gamma log measures the radiation of U, Th and K cumulatively, and the spectral gamma-ray log presents the radiation of each of the previously stated radiogenic elements, separately.

As far as evaporites concerned, these logs help trace basically evaporites that consist of high percentages of potassium salts (10-50% by weight), like carnallite, polyhalite and sylvite. That is because, evaporites containing potassium salts can be easily distinguished from marine shales and carbonates or even anhydrite and halite, all of which emit somewhat, yet quite lower, radioactivity. Halite and anhydrite yield values on the gamma log scale that are extremely low compared to halite that comprises potassium salts (Warren, 2018).

3.3.3 Bulk density or density logs (RHOB)

Bulk density logs are measuring electrons density, thus giving us a quantitative approach to the specific gravity of each formation and its fluids combined. Electron density is the close numerical counterpart of the formation's specific gravity (gm/cc) and measures changes in the average total density of the formation. However, the electron densities of some minerals, such as halite and sylvite, are not inversely proportional to their specific gravities. So, it is necessary to use apparent bulk density for these minerals, which is easy to do since several of the evaporite minerals differ enough in bulk density to allow for identification.

Many evaporites are relatively pure, containing only one or two minerals. As a result, if its lithological composition cannot be positively recognized from the density log, it can be suspected. The densities will change though, if impurities exist. Thankfully, the majority of relatively pure evaporites tend to provide intervals of consistent density with little change. When this happens, pure evaporite logs can be easily compared with the ones of interest and help with their identification (Warren, 2018).

3.3.4 Neutron logs

Neutron logs or neutron porosity index logs continuously record the formation's response when it is attacked by fast neutrons. They basically measure the H concentration in a rock, either that comes from the H_2O in hydrated salts (carnallite, gypsum) or from the H_2O or oil in other non-evaporitic formations. The neutron log is used to quantitatively assess porosity in limestone-equivalent porosity units, and qualitatively as it can easily discriminate oil and gas in areas where no hydrated salts exist. It can be used to determine raw lithology and thus characterize hydrated minerals, volcanic rocks, zeolites, and evaporites (which present negative porosity values). When combined with density logs their effectiveness is magnified, regarding the confirmation of evaporites existence (Warren, 2018).

3.3.5 Sonic or acoustic logs

Sonic logs are measuring the ability of rock formations to transmit acoustic waves, which reflects on rock's porosity, texture and lithology. Once an initial diagnosis of evaporites has been achieved by another method, acoustic logs can be used to accurately detect evaporites due to the fact that the majority of evaporites have incredibly low porosities, and are frequently reasonably pure, though some extra measurements should be combined in order to make more reliable assumptions (Warren, 2018).

3.4 Mechanical properties of evaporites

3.4.1 Creeping

When exposed to differential stresses, evaporites creep under isovolumetric conditions. This is a unique property of evaporites.

When considering drilling through salt, stress differential is imposed through the difference between the formation (evaporite) pressure and the hydrostatic pressure within the wellbore. It should be noted that, in this case, the creep rate of evaporite is strongly affected by temperature too. Given an example, there is an offshore well in GoM, where the temperature at the top of the evaporite was measured at 118°F while at the bottom was measured at 200°F. Considering that the stress differential regarding the hydrostatic pressure in the well and the formation in-situ stress, is the same across the whole section of the salt layer, then the creep rate of the evaporite at the bottom would be faster by 100 times (Wang & Samuel, 2016).

The creep rate also depends on other factors, such as confining pressure, grain size, and the amount of free water or gas bubbles within the formation. E.g. for a certain regime of differential stress and temperature, halite's creep rate is two orders of magnitude slower than anhydrite's. Geomechanically, creeping can be interpreted as the deformation of a rock that occurs due to the dissipation of the strain energy that is generated from the stress relief in it. Considering well drilling, salt creeping might lead to unfortunate events like pipe stuck or casing collapse, even though the creeping rate is slow.

Typically, there are two or three creep phases for salt (Figure 3-3). The strain rate is at first noticeably high after the stress differential is applied (transient creep phase), but decreases with time until it reaches a steady strain rate constant (steady-state creep phase stage). A third phase, known as accelerative or tertiary creep, may manifest depending on the temperature and differential load placed on a salt specimen. In this phase, there is an acceleration of the creep rate, because of the degradation of the specimen structure (due to the accumulation of creep strain with time). During this phase dilation starts, and volume increases, thus micro-fractures might occur leading to failure.

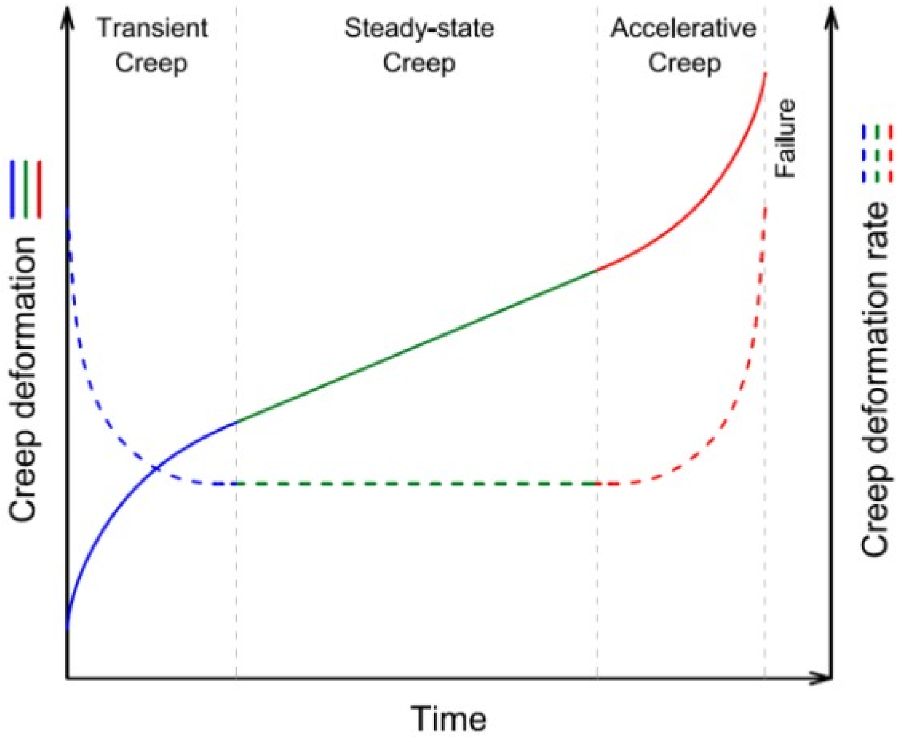

Figure 3-3. Test results regarding creeping for a sample of salt rock (Wang & Samuel, 2016)

When it comes to well completion, deformations are not that likely to appear so there is no big probability for the creep rate to reach the third stage. In salt, the overall strain rate because of creeping is the sum of the transient creep rate with the steady-state creep rate (Wang & Samuel, 2016).

3.4.2 Strength

There is an extended range in the uniaxial compressive strength of salt formations. This is attributed to the degree of cementation they present. There are salt formations tightly cemented which present quite high strength, while other salt formations are loose and can be easily broken by hand. The average range of uniaxial compressive strength of salt formations is between 15 MPa (2,175psi) and 35 MPa (5,075psi) (Fjær, Horsrud, Raaen, Risnes, & Holt, 2008). Regarding the salt strength from deepwater formations, not very much has been published, but approximately its unconfined compressive strength is around 3,200 psi (22 MPa) (Wilson & Fredrich, 2005).

One of the main characteristics of rock salt is its low resistance to tensile stress. So, the tensile strength for salt formation may be from less than 1 MPa up to 2-3 MPa. Salts' compressive strength can be up to 20 times more than its tensile strength (Silberschmidt and Silberschmidt, 2000). Young's modules for different types of salt formations range from 10 to 30 GPa, while Poisson's ratio is between 0.15 to 0.4 (Hansen et al., 1984).

The creeping behavior of salt, mentioned earlier, goes along with its plastic behavior. Specifically, creep strain is proportional to deviatoric stress and temperature (Fjær, Horsrud, Raaen, Risnes, & Holt, 2008). This phenomenon can be modeled macroscopically as metal plasticity.

3.5 Geomechanical challenges in and around salt formations

3.5.1 Overview

Trouble awaits when drilling not only within salt but also around it. These troubles are related to the uncommon properties and behavior of salt minerals. So, there is a whole range of potential hazards that may appear during the drilling process not only within the salt formation itself but also near and especially below it. The hazards are directly or indirectly related to the following factors (Wilson & Fredrich, 2005), which are discussed in the following paragraphs:

1) The structural setting of the deformed sediments adjacent to the salt formation.
2) The difficulty in pore pressure prediction beneath the salt formation.
3) The stress regime and the stress anomalies in the area caused by the presence of salt.

The occurrence of any of the hazards that will be mentioned below depends on the nature of the salt's movement in relation to the state that its components are lithified.

3.5.2 Structural deformation around salt diapirs

To shed some light on how near salt geomechanical hazards are related to the structural deformation around salt formations, a basic understanding of the mechanics of how sediments around salt deform, as well as which is the rate of sediment lithification relative to diapirism, should be built. To that end Wilson, 2005 identifies the following cases of structural deformation around salt diapirs.

3.5.2.1 Diapirism and related deformation

The type of diapirism governs the process of deformation around the salt. More specifically it is considered to be two main processes of deformation. The first is described when salt penetrates the sediments lying above it (plain diapirism), while, the second is when diapirism happens at the same time as the thermal subsidence of the sediments lying above (Figure 3-4). The seismic section in Figure 3-4 is interpreted as diapirism must have been effective at the same time when sedimentation of the younger sediments occurred. The result was the slow upward expansion of the diapir, while the younger sediments subside around it.

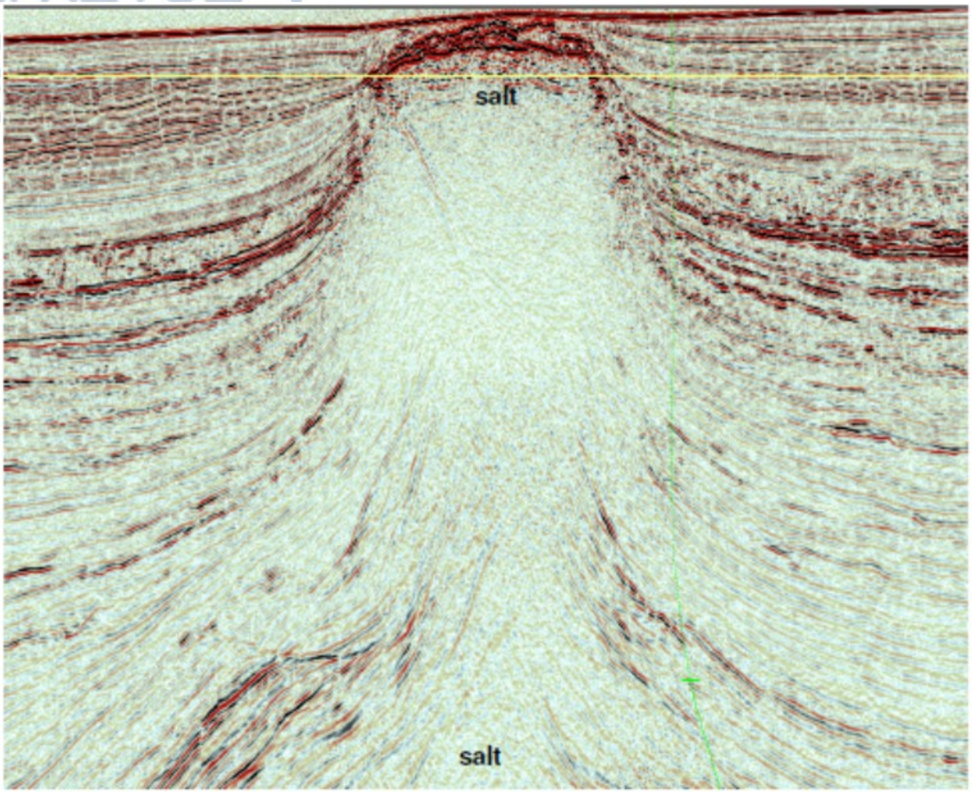

Figure 3-4. Seismic section showing the subsidence of sediments around a salt diapir (Wilson & Fredrich, 2005)

Within the sediments next to the salt, the diapir shown in Figure 3-4 shows fully mature zones of frictional drag. These zones are the result of the salt's tendency to drag nearby sediments as it moves upwards in relation to the adjacent sinking strata. They are examined further in the next paragraph. An inversed salt base may arise where the salt is implanted firmly into a much deeper salt layer, causing other sediments around it to inverse as well (Figure 3-5). When evaluating geomechanical risk, there must be a valid identification between these inversed sediments and those inversed due to frictional drag because the mechanical forces affecting these sediments may be very different (Wilson, 2005).

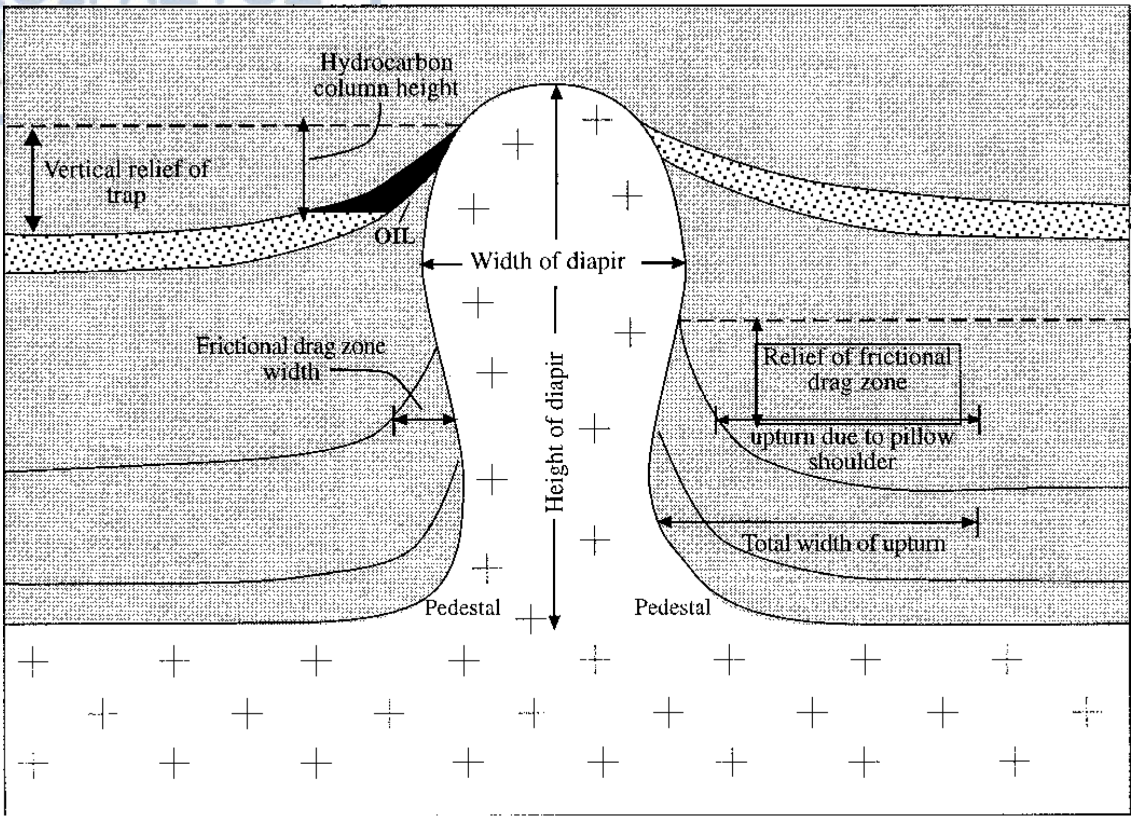

Figure 3-5. Inversed zones of sediments and frictional drag zones above the salt base (pedestal) (Davison, et al., 2000)

3.5.2.2 Drag zones adjacent to salt diapirs

The zones, previously mentioned as frictional drag zones, consist of highly strained sediments developed next to the diapirs' developing edges. They are developed as the sediments around the growing diapir walls are reversed either at an abrupt angle to the diapir walls or as an envelope around them. Drag zones should not be confused with broader zones of inversion produced by layers assimilating the shape of the inversed salt base (salt pedestal) (Figure 3-5). Drag zones present poor seismic interpretation (Figure 3-4) due to the abrupt inclined shape of the rotated sheets of sediments within the drag zone.

According to Alsop et al. (Alsop, Brown, Davison, & Gibling, 2000), there are four main categories of anamorphosis styles in drag zones near salt (Figure 3-6). Uniform and consistent sediments near salt deform primarily plastically and only limited faults are developed. Deformed sediments may be spread over side by side to the salt edges, forming a groove zone, if sedimentation and diapirism occur, close to the surface. This kind of deformation extends laterally only a few feet wide. Next anamorphosis style recognized applies in non-uniform sediments overlying the salt diapir, specifically those that were partially lithified during diapirism. In this case, a significant number of faults are developed extending a few hundred meters away from the salt edge.

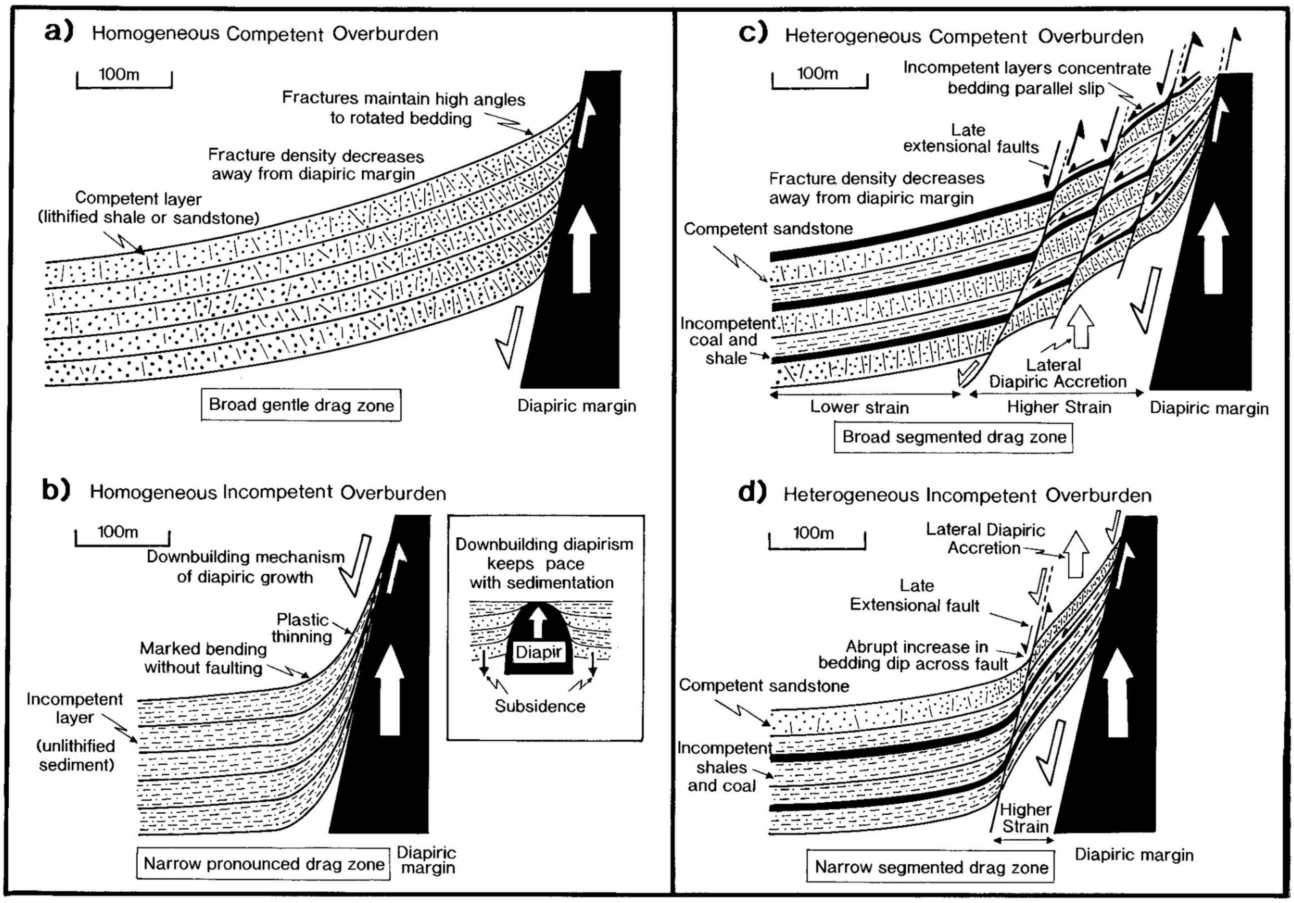

Figure 3-6. Basic types of deformation styles in drag zones next to salt diapirs according to (Alsop, Brown, Davison, & Gibling, 2000)

Regarding the geomechanical challenges in drilling through these drag zones, it is clear that they are related to the formation status next to the salt. When these formations are homogeneous bear limited problems, with the possible exception of the small zone that may exist next to the diapir in the case of fast-sinking sediments. Thereof, the possibility of the borehole trajectory, even very inclined, to divert “parallel to bedding” when exiting salt is very limited.

The most severe challenges are related to the stability of the wellbore when the formations next to the diapirs present heterogeneity. But for this to happen, the surrounding sediments had to be rather ancient, so that they have been lithified up to a certain degree when the diapirism commenced. So, the age and the degree of lithification of the surrounding formations are the major factors regarding the development of drag zones next to salt, (Wilson, 2005).

3.5.2.3 Drag zones and inversed sediments under salt

During their development, salt diapirs can extrude from the sea floor and then move sideways, creating salt extends if they are overlain with sediments and later buried under them. In such a case, when the lithification state and the consistency of the sediments under the salt are low, remarkable deformation occurs. In the Gulf Coast Shelf, researchers described inversed sediments that could have a thickness of several hundred feet (Figure 3-7). This kind of deformation below salt may pose risks for well drilling, causing severe deviation in wellbore trajectory (Wilson, 2005).

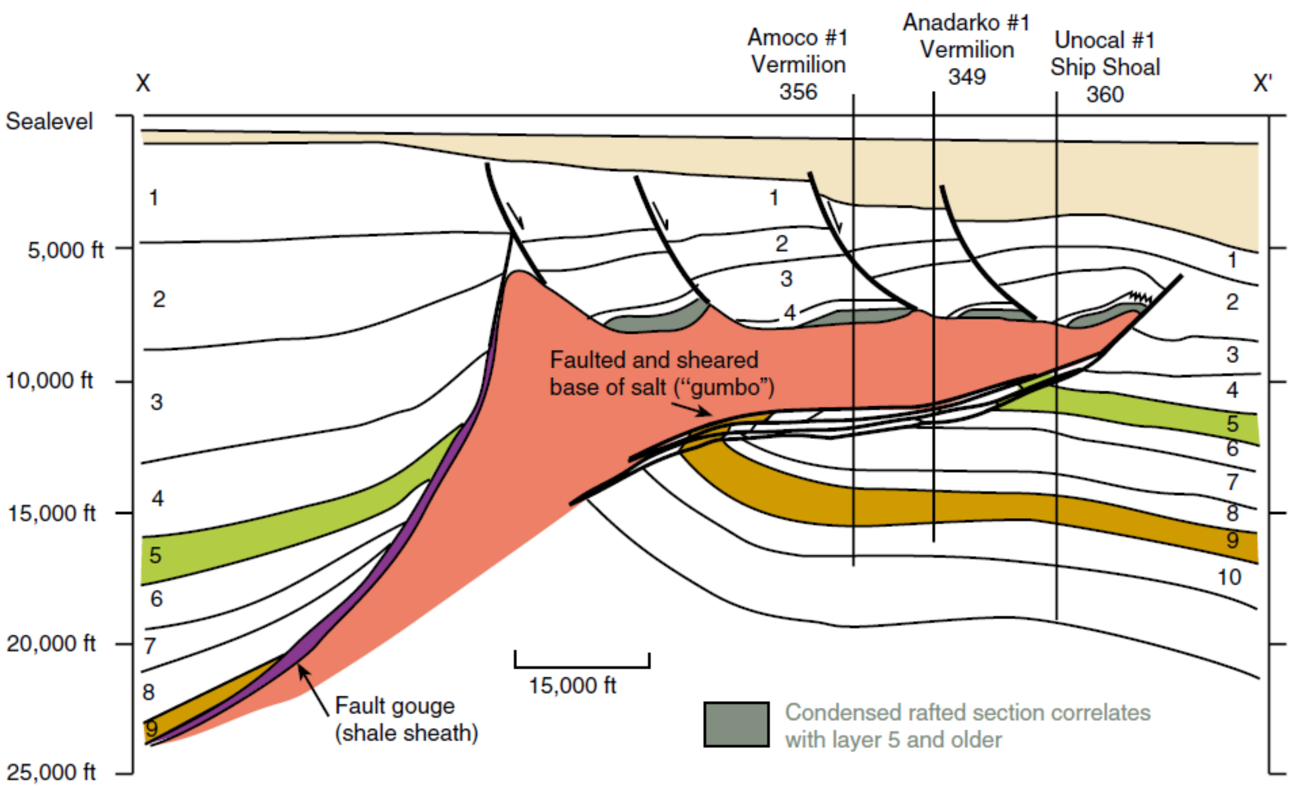

Figure 3-7. Basal shear model after Harrison & Patton, 2005 – Inversion of sediments below allochthonous salt (Warren, 2016)

3.5.2.4 Toe-thrust features near thrust sheets of salt (nappes)

In near-surface ledge margins of salt deposits, normal faults can take place, as a result of salt pressure release. Toe thrusts appear sometimes next to salt, under thrust-faulting stresses (Figure 3-8). So, it can be said that, from a geomechanical point of view, above salt come areas with low fracture gradients (existence of weak sediments in frictional equilibrium under a typical stress system due to faults), while, next to salt, areas are under higher stresses (even though in such weak sediments the absolute size of the stress differential cannot be very high). Come that as it may, these regions should be very well examined to prepare the proper mud weight program for drilling through them.

It should be noted that there are toe thrusts next to salt diapirs that have been topped by more recent sediments. Stresses in such conditions usually equilibrate as time passes coming to be analogous to the lithostatic stress system or of normal faulting. However, that does not mean that deranged stresses and fractured formations should not be taken into consideration in well design. It should be stated that wellbore instability is more likely to happen when drilling takes place very close to a salt diapir tongue, as opposed to drilling in farther out distance (Wilson, 2005).

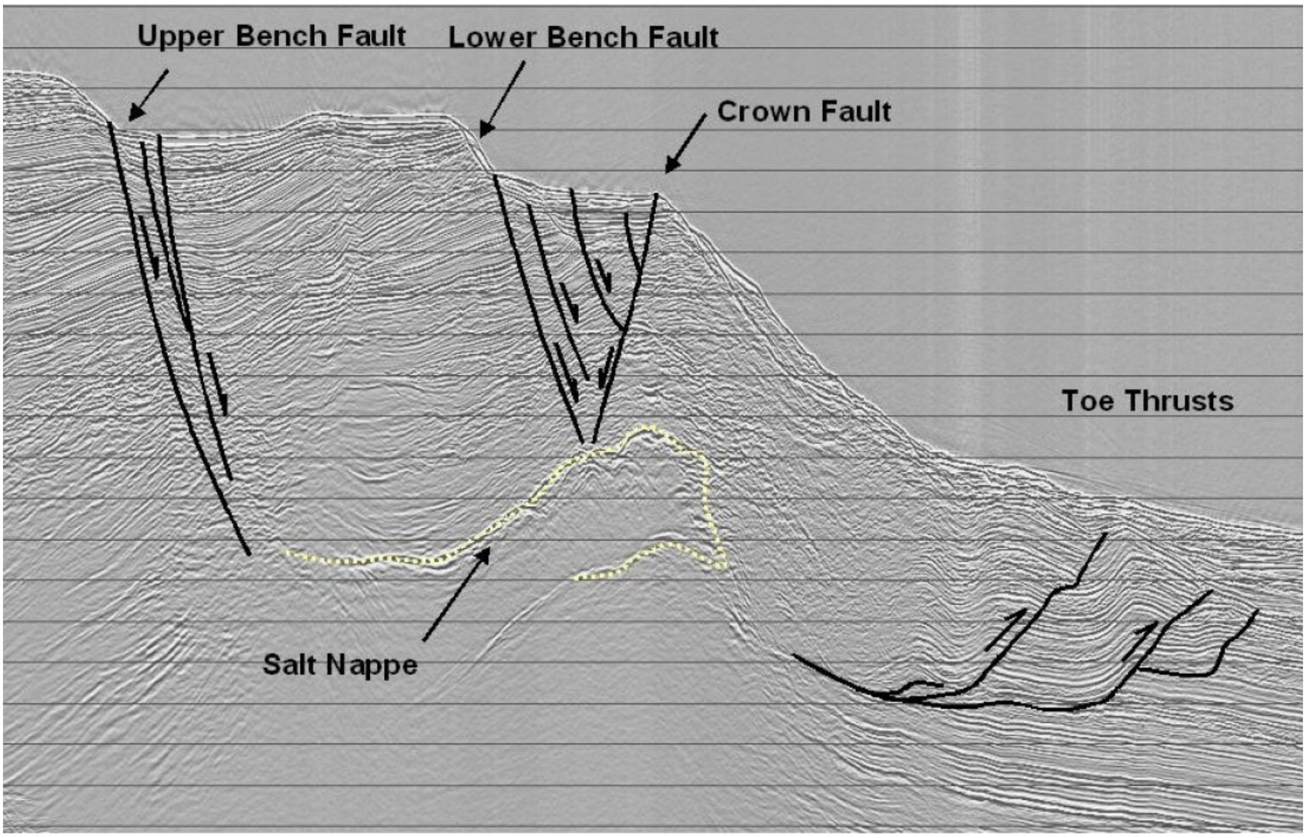

Figure 3-8. Seismic section showing normal faults above a sheet of salt (salt nappe) and toe thrust features next to it (Wilson & Fredrich, 2005)

3.5.2.5 Faults around salt diapirs

Sometimes, other kinds of faults in the vicinity of up-rising diapirs might even act as caps or traps for oil and gas accumulations. The existence of outspreading faults above and around up-rising diapirs, even at a considerable distance from them (6-10 km), is very common. Not very often such radial faulting is produced mainly by the expulsion of mass from the original salt layer in the depths. More frequently radial faulting observed around penetrating diapirs, is attributed to the uprising movement of the diapir that penetrates the overburden, especially in the deep sea. This kind of faulting is clearly observed in the North Sea (Figure 3-9). Radial faults convert into polygonal faults afar from the diapir in deep water changes. Both of those faulting styles can cause problems in drilling, such as loss of circulation and/or wellbore instability (Wilson, 2005).

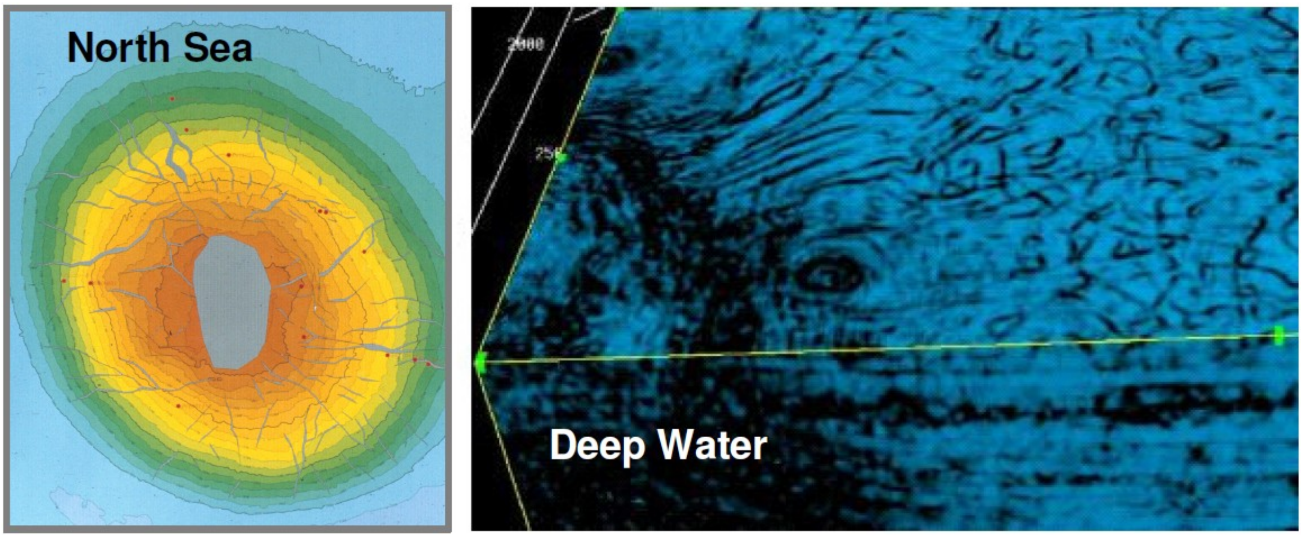

Figure3-9. Radial faults around piercing diapir in the North Sea (Wilson & Fredrich, 2005)

Figure 3-10 presents faults above a salt dome in the Gulf of Mexico, while Figure 3-11 shows a cross-sectional schematic of normal faults above shallow (Figure 3-11a) and deep (Figure 3-11b) piercing salt diapirs. In general, in deep diapirs, normal faults are observed above them (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

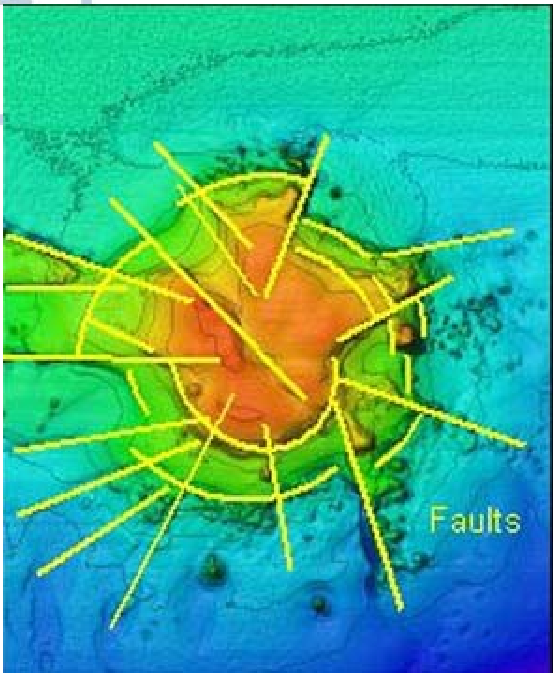

Figure 3-10. Normal faults above salt dome in the Gulf of Mexico (Dusseault, Maury, Sanfilippo, & Santarelli, 2004)

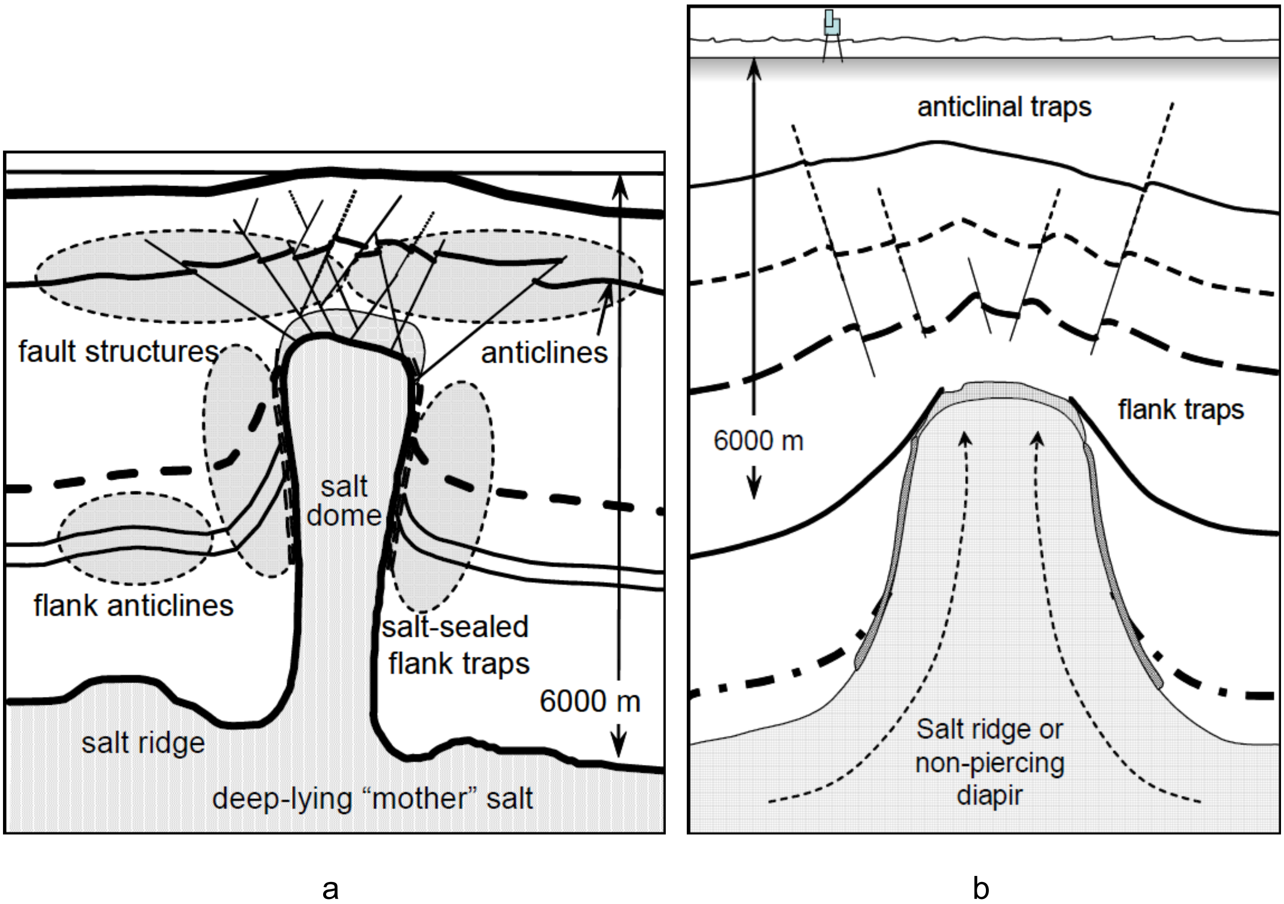

Figure 3-211. Cross-sectional schematic of normal faults above shallow (a) and deep (b) piercing salt diapirs (Dusseault, Maury, Sanfilippo, & Santarelli, 2004)

3.5.3 Pore pressure beneath salt sheets

Due to the unreliable interpretation of seismic velocities through salt zones, the estimation of pore pressures below the salt is quite difficult. This poses great concern in well design and construction, regarding the exit from salt. There are methods for evaluating the reliability of projected mud weights for developing an appropriate salt exit mud weight (Wilson, 2005).

The reliability of models interpreting seismic velocities to estimate pore pressure profiles depends upon two components: pertinent velocities and vigorous translations of seismic velocities to effective stress. Up today, although a lot of work has been put into solving the issue of poor velocity quality below the salt, and even though velocity models for imaging below salt have certainly improved, seismic velocities now available below salt are still frequently insufficient for comprehensive pore pressure calculations. Subsequently, these models are probably effective for post-drilling analysis and normally ineffective for well design.

When seismic imaging below the salt is suitable for correlations and there are offset wells penetrating strata similar to the interval of interest, then pressure estimations at those wells can be projected to the well of interest. Similar to this, it is occasionally possible to carry out seismic-based pressure calculations in portions that are not affected by salt and then project these findings to the well of interest, as illustrated diagrammatically in Figure 3-12. These two methods are applicable only where sediments are associated and can be correlated. These methods fail in isolated intervals like the one shown in Figure 3-12.

In some cases, researchers have given considerable attention to how confining stress affects pore pressure. It provides a different approach for the evaluation of prospective pressures in isolated and salt-sealed formations. Instead of a direct pressure evaluation, confining stress offers an upper limit on potential pressures. However, in situations of sediments packed between formations of low permeability in the early stages of deposition, current pressures can reach that upper bound. (Hauser, 2020)

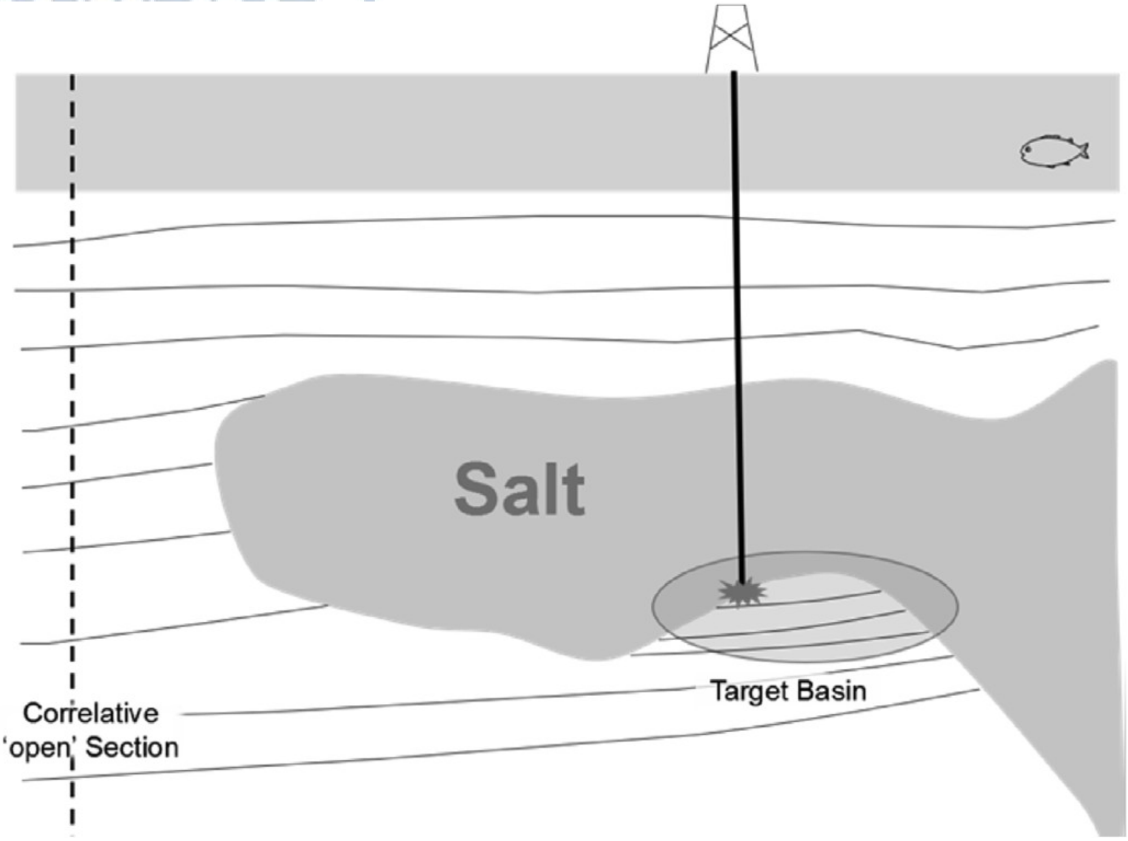

Figure 3-312. Pressure prediction below salt in areas where is thought to be hydraulic communication between the sediments can be based on pressure estimations in adjacent salt-free areas and projected or correlations to the desired spot. However, in areas completely isolated by the salt body, this strategy does not apply (Hauser, 2020).

There are, also, models that represent the interaction between pore pressure, stress, and geologic deformation. These models shed light on how pore pressure and stress influence geologic evolution, which has produced in the first place pore pressures and stresses. Their results help us better understand how pressure, tension, and deformation interact in salt basins and how these properties may affect certain structural features of the basins, such as welds, upturned flaps, and overturned folds. Such models offer further a methodical strategy to include mechanical behavior in various geologic systems, where sedimentation, stresses, and pore fluids are related. For instance, a study by Gao et (2018) on fold-and-thrust belt systems clarified how shear affects porosity loss within the key wedge and gave a prediction of stresses in the block of rock which lies on the underside of the inclined fault. (Nikolinakou, Flemings, Heidari, & Hudec, 2018)

In general, significant problems, commonly, appear when pore pressures are misinterpreted regardless of whether those "miscalculations" happen beneath, above, or inside the salt structures (Chatar, Mohan, & Imler, 2010).

3.5.4 Stress regime around salt

Intrusive salt structures significantly unsettle the in situ stresses in and around their mass. Lithostatic stresses within the salt mass, along with the continuousness of deformations on the margin between the salt mass and the surrounding formations, can lead to stress rotations in the layers next to the salt, especially where salt overhangs exist, or encourage alterations in horizontal stresses. When these alterations are significant, shear failure may appear to the formations next to salt. It should be noted that rubble zones next to salts might be attributed to these phenomena (Wilson, 2005).

While salt domes' diameters usually reach 1 to 3 km, stress alterations of adjacent formations, caused by them, appear on a level of 10 to 20 km circumferentially. Stresses might not reflect this influence though when the following tectonic events overprint these alterations and that is a factor confusing the interpretation process, while on the other hand, the dominant stresses are usually distinct.

Figure 3-13 gives us a general example of the stress regime around a salt dome, showing the outwards faulting of the formations next to the salt dome, extending in all directions. It is difficult to compute the extent of plastic deformations inflicted by salt stresses. Moreover, it is even harder to compute this factor or even porosity loss, slip of bebbing planes, and sedimentation sequence on the upper edges of the dome. The area in which thrust faulting is the dominant stress regime is off the top of a salt dome as a result of the outward deformations' and geometry's influence (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

In normal conditions, the vertical direction of stress is the dominant one, when it comes to stress fields in a rock mass, but this is not usually the case especially in salt diapirs because of the alterations one can initiate. It should be stated that promoting an axis rotation, is what needs to be done to come up with the dominant directions at any point. This situation is shown in Figure 3-14. In Region 1 (Figure 3-14a) stress distribution is not influenced by the salt diapir. The vertical direction coincides with one of the principal directions. In Region 2 (Figure 3-14b), the stress distribution is strongly influenced by the salt diapir, as the vertical direction does not coincide anymore with one of the principal directions, and, consequently, the shear stress changes due to the salt piercing. In Region 3 (Figure 3-14c) stresses are also influenced strongly by the salt diapir. Here, due to an axis rotation, only normal stresses are acting, meaning that the directions shown are the principal directions (Salmazo, Mendes, & Miura, 2013).

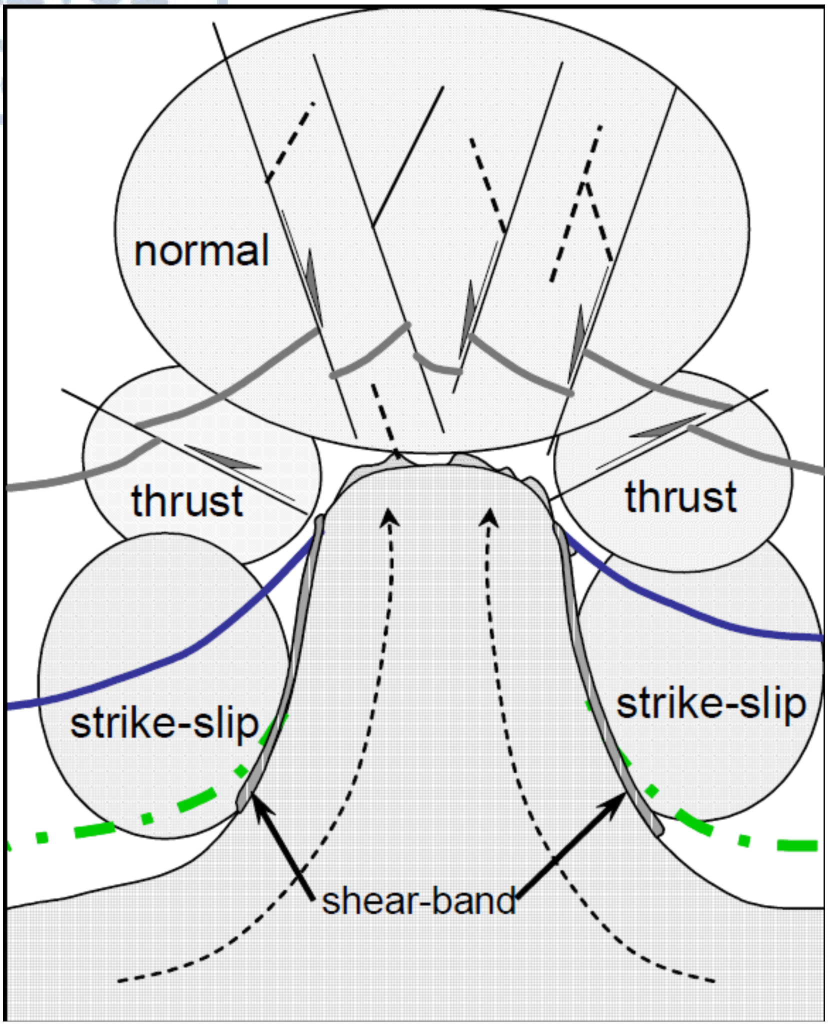

Figure 3-413. Schematic of stress distribution around a salt diapir

The hazards related to the properties and the behavior of salt formations, as well as the problems and challenges arising in drilling through and around salt, are examined in the next chapter.

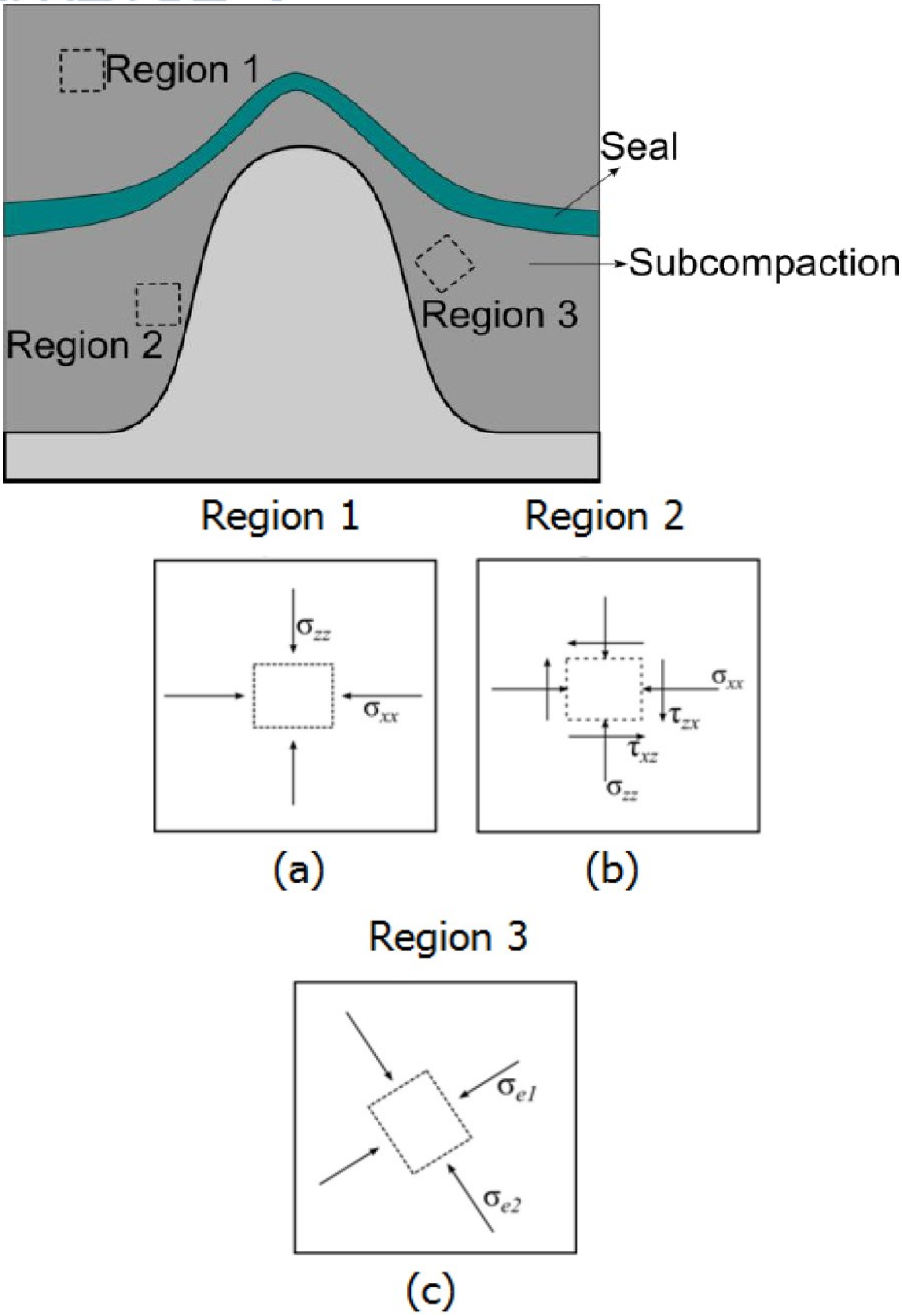

Figure 3-514. Stress distribution in different regions around a salt diapir. (a) stress in Region 1 not influenced by salt diapir, (b) & (c) stresses in Regions 2 and 3 strongly influenced by salt diapir (Salmazo, Mendes, & Miura, 2013)

CHAPTER 4. HAZARDS AND CHALLENGES IN SALT DRILLING

4.1 Introduction

Oil and gas companies around the world avoided dealing with salt intervals up until the 90s because of the high risks. These high risks even affected contract agreements if salt was to be found, not only financially, but also regarding deadlines and related penalties (Perez, et al., 2008). In this chapter, the many geomechanical hazards that need to be taken into consideration to ensure successful drilling not only through but also above and below salt will be discussed.

As previously stated, loss of circulation and/or wellbore instability may appear because of the deformation of sediments around salt, as well as of the perturbed stresses that occur on salt intervals (Wilson & Fredrich, 2005). While salt formations, even after being buried, maintain a relatively low density, all the other formations around them at the same depth and deeper get denser over time as overburden is deposited. When overlying strata do not resist salt movements, salt heads upwards, creating rubble zones below and next to salt, which is hard to model. Well control through and around salt is thus of extremely high risk, due to the difficulty in modeling pore pressure and fracture gradients and the existence of fractured zones, especially when drilling through the salt base.

But also drilling through salt presents significant difficulties. Salt considerably deforms under continuous steady stress over time, depending on the loading conditions and its physical characteristics (creeping). During drilling, salt creeps into the wellbore to fill the void left after the removal of rock volume by the drill bit. Being that as it may, if the temperatures in the wellbore are relatively high, salt creeping happens quickly enough to cause stuck pipes and may eventually require well abandonment or sidetracking.

Shocks and vibrations induced downhole in every formation being drilled should also be considered by drilling engineers when drilling salt formations, as they might get more intense. Apart from salt creeping and salt structure (poor salt quality and/or lamination), this may be caused also by improper equipment selection and BHA design, wrong drilling fluid selection, and suboptimal drilling parameters like weight on bit and rotation speed.

On the contrary, it should be noted that some physical properties of salts present a positive influence on drilling. For instance, salts' fracture gradients are usually high, allowing drilling of longer borehole sections between casings setting depths. Moreover, salt's low permeability, apart from offering secure traps for hydrocarbons, also leads to the avoidance of well-control issues that arise when drilling through more permeable strata.

Drilling engineers have combined several currently available technologies to maximize benefits while limiting salt's inherent disadvantages, such as rotary steerable systems (RSSs), polycrystalline diamond compact (PDC) bits, and concentric under-reamers. These tools originally developed for use in extended-reach wells have been modified for drilling and steering through large salt formations. These tools will be presented in this chapter, along with other techniques, such as drilling fluids management, used to drill safely through and around salt, while also meeting the unique economic and technical requirements of deep-water locations. As previously stated, exploration of offshore salt formations is taking place around the globe in places like Brazil, West Africa, and Canada, while fields, like those, in the Gulf of Mexico, have already reached the stage of production. GOM is an authentic laboratory for the investigation of salts on a full scale, not only for deep water but also for deep drilling. Increasing depths, where pressures can exceed 25,000 psi, pose enormous strains to equipment, both at the surface and downhole, and pressure control equipment. Tools must be pressure rated. This can be up to 30,000 psi in the same wells (Perez, et al., 2008).

4.2 Geomechanical hazards in drilling through and around salt

Figure 4-1 presents a summary of the potential hazards that may appear during drilling through and around salt formations, to be discussed below. The manifestation of any of the following hazards, although any of these can occur, depends on the salt's evolution in relation to how lithified the nearby sediments are. These hazards in relation to their position above, within, or below salt, are summarized in Table 4-1.

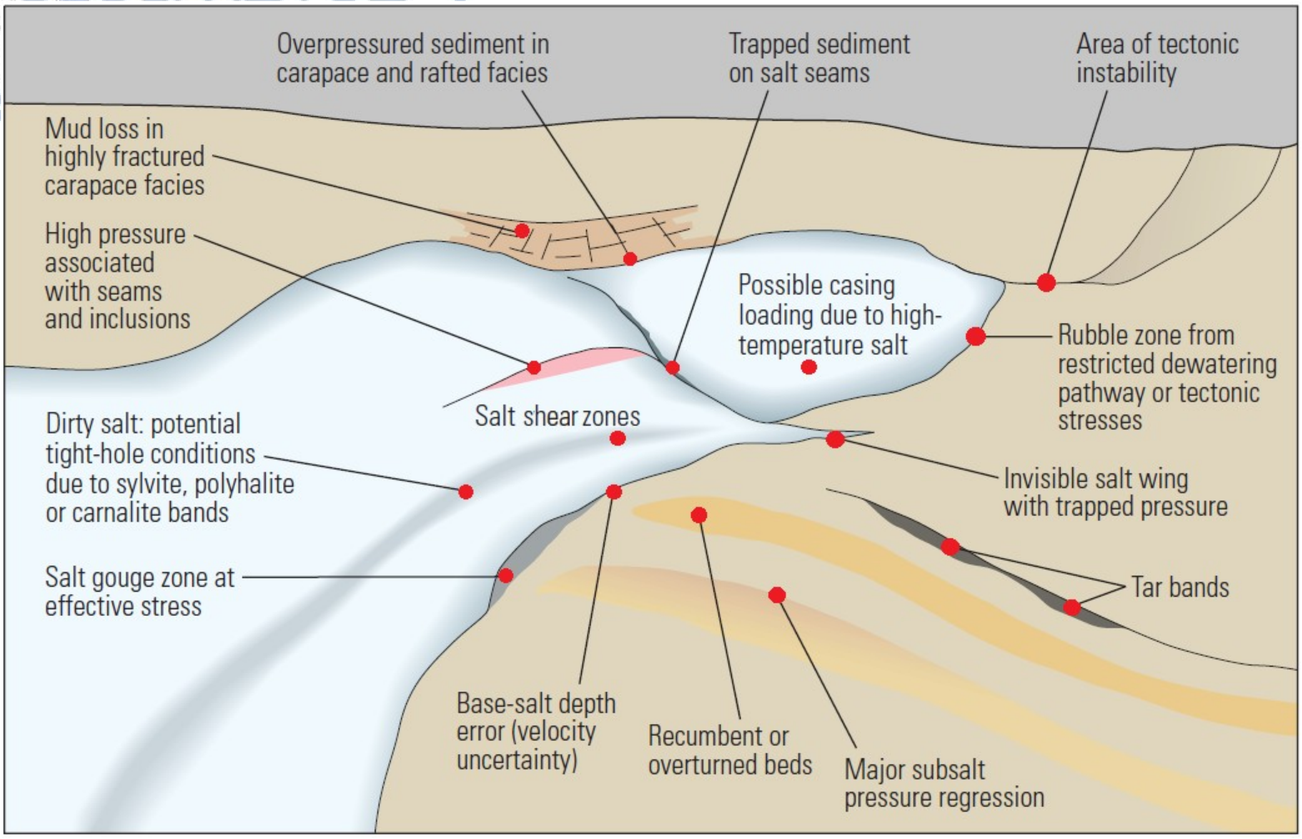

Figure 4-1. Schematic of geomechanical challenges in drilling through and near salt formations, edited by (Perez, et al., 2008)

Table 4-1. A summary of potential hazards that may appear during drilling above, through, and below salt formations

Description	**Above salt (supra-salt)**	**Within salt (through salt)**	**Below salt (sub-salt)**
Tectonically unstable zone	X		
Rubble zone			X
Undetected salt flanks of elevated pore pressure			X
Occurrence of tarry bitumen/asphalt bands			X
Significant pressure decline below salt			X
Overturned sediments near salt			X
Uncertainty in the depth of the salt base			X
Plasticized sediments below salt			X
Salt sections causing tight hole conditions (“dirty salts”)		X	
High-pressure zones in salt due to seams and/or inclusions		X	
Highly fractured thin layers of sediments in contact with the upper face of salt	X		
Over-pressured thin layers of sediments in contact with the	X		

Description	Above salt (supra-salt)	Within salt (through salt)	Below salt (sub-salt)
upper face of salt			
High-temperature zones in salt (creeping)		X	
Entrapped sediments on salt seams	X		
Shear zones in salt	X		

To conclude, stress and pressure regime, associated with porosity (pore pressure and fracture gradients), along with temperature (creeping) are the driving forces behind any of the drilling hazards mentioned above. Next, the challenges derived from these hazards in well design and well construction will be discussed.

4.2.1 Drilling above salt (supra-salt drilling)

As depicted in Figure 4-1, potential hazards during the drilling of the formations above salt are the following.

4.2.1.1 Tectonically unstable zone

A significant rise in the regional stress regime that differs from the one working on a basin-wide scale might occur by active lateral deformation of salt caused by toe-thrusts offshore associated with salt expansion and/or faulting. If the minimum horizontal stress is almost equal to the one of the overburden and the maximum horizontal stress exceeds the overburden stress, stress systems causing thrust-faulting may appear, causing wellbore instability (Wilson & Fredrich, 2005).

4.2.1.2 Highly fractured thin layers of sediments in contact with the upper face of salt

When sediments, that are in an advanced stage of lithification, move up due to the uprising movement of salts, their pressure decreases causing their structure to get fractured (as they progressively “depressurized” being previously under higher pressure and in-situ stresses). Moreover, sediments above salt tend to extend along with the lateral displacement of the salt mass. These zones of the extension might get under low horizontal stress regimes. Both previously mentioned cases lead to losses of circulation when drilling through these sediments above the top of salt (Wilson & Fredrich, 2005).

4.2.1.3 Over-pressured thin layers of sediments in contact with the upper face of salt

The so-called, carapace formations, which are thin pelagic and hemipelagic sediment veneers deposited atop submarine salt glaciers, are characterized by high pressures, which are believed to be related to the migrated rafted sediments that salt diapirs strayed along with. These, mixed with salt, sediments do not have the time to dewater, due to the relatively faster rise of the diapir, ending up being under high pore pressures. It should be noted that more recently deposited sediments could be under lower overpressure if there was an acceleration in salt's deformation rate in recent times. Tight hole and gumbo shale behavior usually prevail in such cases (Wilson & Fredrich, 2005).

4.2.1.4 Shallow gas pockets above salt

Sandstone layers, that are enclosed by geochemically reactive, or highly ductile, more soft shales (smectitic shales), might end up with low fracture gradients, due to the lateral extension of underlying salt. Under these circumstances, it is possible drilling through this section to face the risk of meeting sandstone masses containing gas. Thereafter the risk for wellbore instability would grow higher. Increased pressures resulting from deeper-located gas can be maintained if such sand masses are sealed by faults (Figure 4-2).

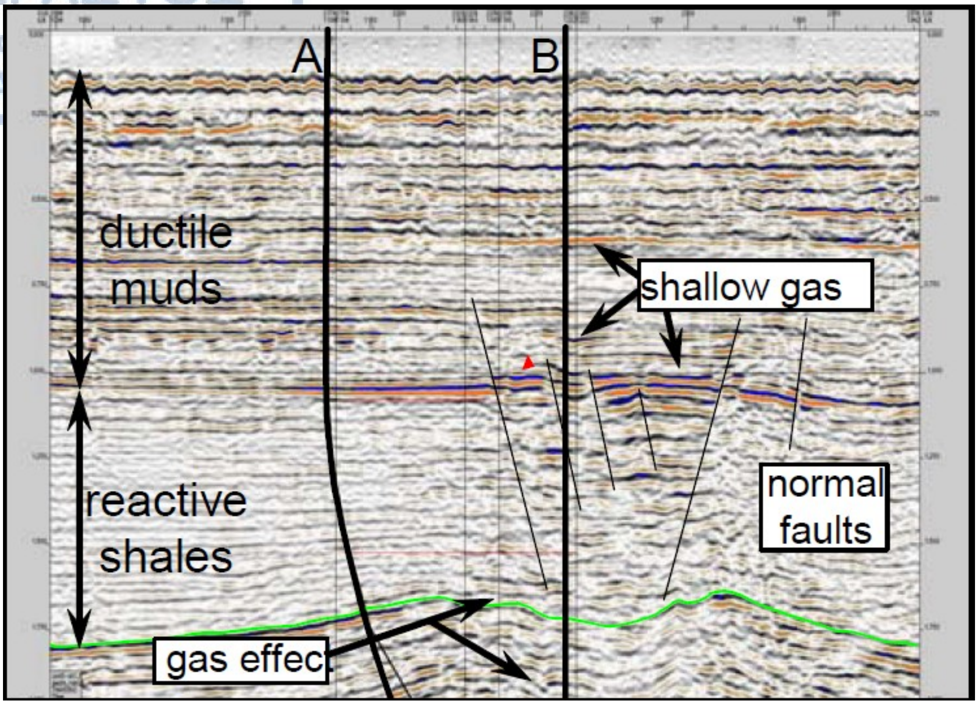

Figure 4-2. Seismic section of shallow depths above salt diapir (Dusseault, Maury, Sanfilippo, & Santarelli, 2004)

Low minimum horizontal stress (σ_{hmin}) and extensional strain above salt masses produce fracturing, thus allowing gas to move in higher strata. Such shallow gas pockets are often encountered. In such cases, severe kicks and even blowouts can happen along with circulation loss, as well as problems from gas entering the drilling mud (as bubbles) causing severely gas-cut drilling fluids. In reactive shales drilled with water-based drilling fluids, there is usually a time interval of several days (for diffusion and heat transfer phenomena to develop) for instability to start. This leads drilling engineers to drill and set casing as fast as possible before wellbore instability starts. However, high rates of penetration in fractured shales containing gas, above salt domes, usually result in severe gas-cutting problems, and thus, it is usually impossible to maintain the appropriate ROP. It is concluded that risk management in shallow sections above salt entails optimizing ROP to save expenses while simultaneously avoiding hazards associated with gas-cut muds.

To deal with the gas-cutting effect, drilling is stopped for as long as it takes to circulate out the gas-cut mud. That procedure, on the other hand, might enhance the problem due to temperature decrease, which diminishes the tangential stress around the wellbore, so that fractures open further. This makes it easier for the wellbore to communicate with more fractures filled with gas, making it harder to eliminate gas-cutting effects. An efficient way to reduce this effect, used in the North Sea, is to heat the mud with produced hot oil.

Drilling of the shallow well sections above salt domes, to deal with the risk of circulation losses and to manage the considerable quantities of the produced drill cuttings (due to the large diameter of the drill hole), drilling engineers use water-based mud, for it is cheaper yet more efficient. Oil-based mud is preferred in areas away from salt masses and in well sections of smaller diameter to handle the ductile reactive shales. Moreover, it is suggested to set one string of casing as deep as feasible, instead of setting a large diameter casing too shallow to deal with such concerns, and thereafter a second string of casing is required for further drilling for safety reasons.

Another way to reduce the hazards of shallow gas pockets is to avoid them. Figure 4-2 demonstrates a simple, yet effective risk-reduction approach in well design above salt domes: trajectory A avoids the worst of the gas pocket that would be encountered in trajectory B. Furthermore, well trajectory A avoids the faulted zone, where formation pressure is likely to be higher, and a longer open hole section can be drilled before casing is set (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

Analogous methods to lower risk can be envisioned for the deeper well sections above salt domes. Figure 4-3 (which is a continuation of Figure 4-2) provides a clear example. Well trajectory A is approaching the target from the side, instead of directly passing through the gas pocket and the area of low minimum horizontal stress (σ_{hmin}) (well trajectory B). In such situations, an inclined trajectory often results in the saving of one casing string or liner with a decreased likelihood of gas-cutting issues. The expense of the extra drilling time must be weighed against the possible cost of an "event," which runs the risk to drill a sidetrack or set a casing shoe too shallow.

Drilling deeper raises the possibility to encounter overpressures, and if the upper casing shoe is set in an area of low horizontal stress, an extra liner string must be installed. In any case, having logs interpretations that can predict the structures and stresses to be encountered would lead to better and more efficient well design (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

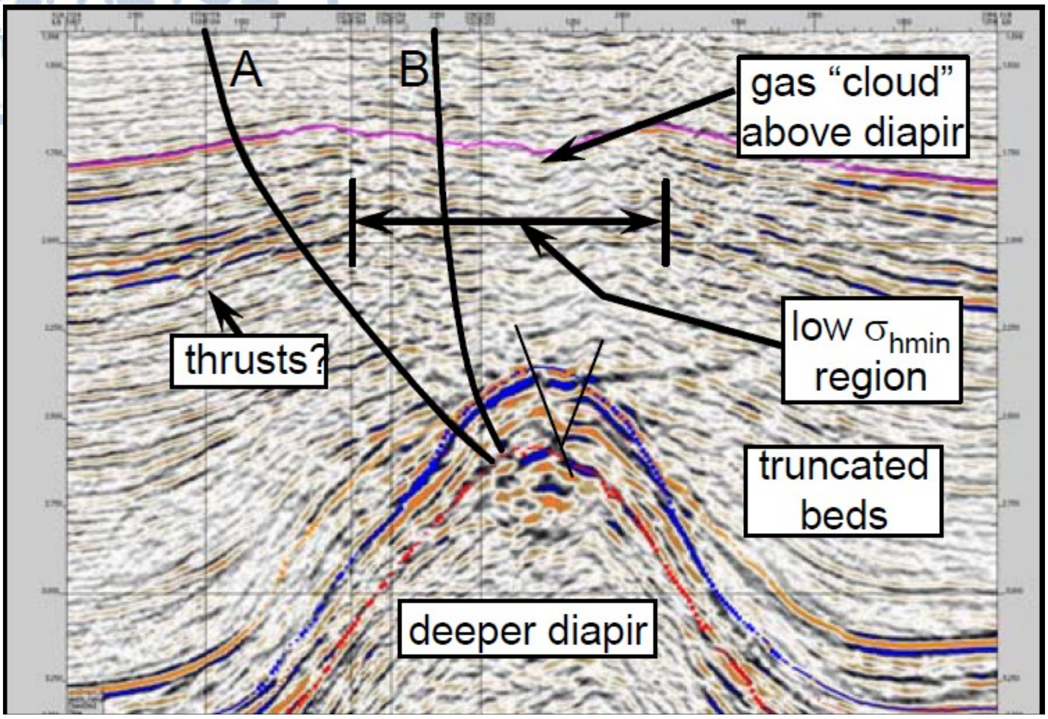

Figure 4-3. Seismic section of the deeper section above salt diapir (Dusseault, Maury, Sanfilippo, & Santarelli, 2004)

4.2.1.5 Entering the salt

When a well reaches the point where it is about to enter the salt, drilling engineers must deal with possible washouts that might occur. So, it is preferable to design the well section entering the salt as vertically as it can be achieved, since even the slightest doglegs can cause torque and undesired side forces to develop, leading to washouts. Another advantage of entering the salt as vertically as possible also helps set the casing strings and completion strings and equipment easily (Mathur, Seiler, Srinivasan, & Pardo, 2010).

4.2.1.6 Summary of supra-salt drilling challenges

The challenges in drilling supra-salt formations are summarized in Table 4-2, in relation to the associated geomechanical hazards.

Table 4-2. Summary of supra-salt drilling challenges associated with relevant geomechanical hazards

Drilling challenges	**Geomechanical hazards**
Wellbore instability	- Tectonically unstable toe-thrusts - Shallow gas pockets
Circulation loss	- Highly fractured sediments in contact with salt - Shallow gas pockets
Tight hole and gumbo shale behavior	- Over-pressured sediments in contact with salt
Kicks and blowouts	- Shallow gas pockets
Gas-cut drilling fluids	- Shallow gas pockets
Washouts	- Entering the salt

4.2.2 Drilling through salt

As depicted in Figure 4-1, potential hazards during drilling through salt are the following.

4.2.2.1 Salt entry

Changes in the stress regime in the region immediately above salt because of its migration pose risks to wellbore stability. If the top of the salt is deeper, fractures and faults are usually observed, caused by salt's upward movement that pushes upwards the older sediments of high pore pressure. Due to this movement older sediments above the salt fracture and their pore pressure declines. When that is the case the possibility of circulation loss problems is increased as the well enters the salt. Over-pressured zones may also exit at the top of salt if the older sediments were unable to depressurize.

Drilling engineers manage to avoid such risks by reducing ROP or/and WOB when the bit is approaching the top of the salt, giving them time for proper risk evaluation and planning. An increase in torque and a decrease in ROP are frequent indicators of top of the salt. A helpful lithological confirmation that the change in drilling parameters can be linked to the top of salt is a gamma-ray measurement within 10 ft of the bit.

By keeping those parameters stable, up until the BHA buries into the salt, there is a chance for a significant interval of salt to be drilled without problems (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

4.2.2.2 "Dirty" salts

Each salt body differs from the others. Nonetheless, the content of each salt body mass may significantly vary from point to point, according to several gamma logs. Salt is described as "clean" or "dirty" salt. Sodium-based salt (halite) is what is called "clean" salt and is characterized by constant lithology. The salt that contains sulfate and/or potassium inserts, is called "dirty" salt since it presents composition variations with depth (Wilson & Fredrich, 2005). Figure 4-4 presents the gamma-ray and resistivity logs, of a "clean" salt, on the left), and of a "dirty" salt on the right (Chatar, Mohan, & Imler, 2010). The variation of the right resistivity curve depicts variation in lithology (presence of inserts or impurities), leading to the classification of as "dirty" salt. The gamma-ray curves for both the uncalibrated (purple) and the API-calibrated data (green) present no significant difference between the two types of salt, leading to the conclusion that they cannot resolute whether the salt is "dirty".

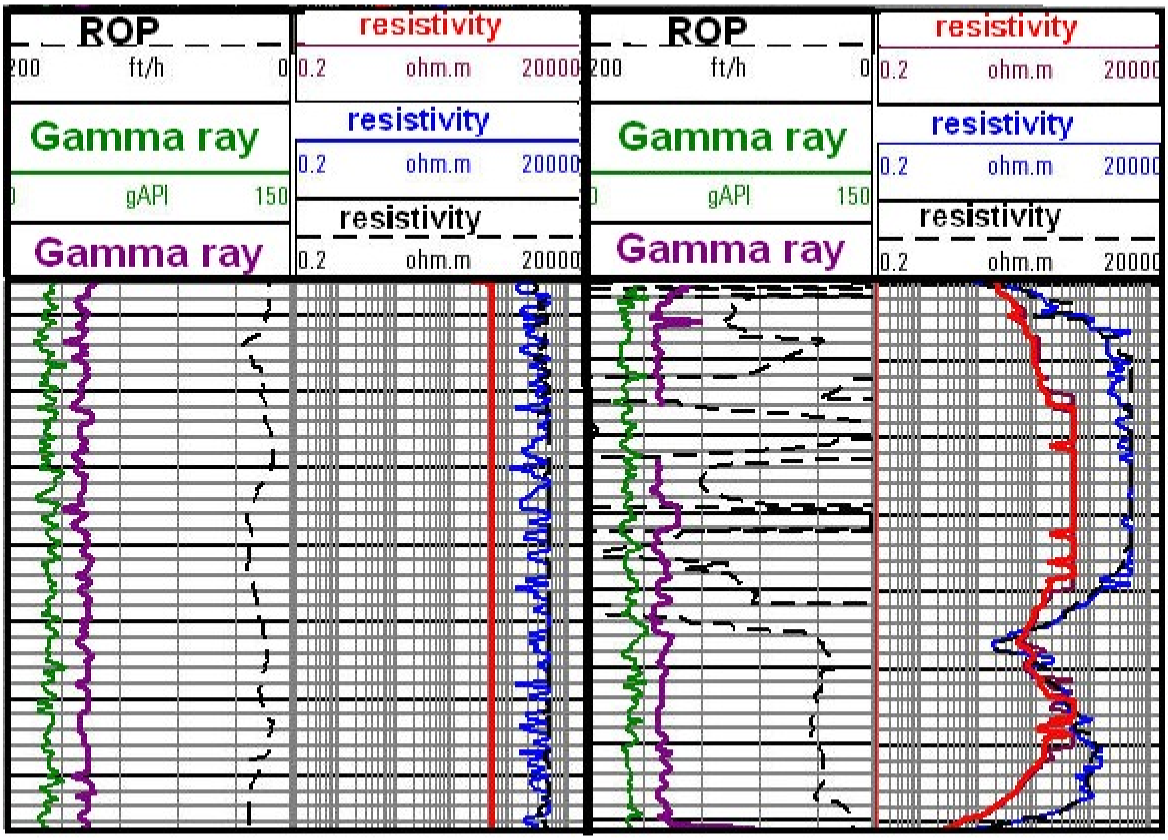

Figure 4-4. Differences in resistivity logs and ROP curves between a clean salt on the left and a dirty salt on the right (Chatar, Mohan, & Imler, 2010)

By observing the Rate of Penetration (ROP) curve of the "dirty" salt, great deviations from the norm (left ROP curve for "clean" salt) are noticeable. The trace of the ROP curve starts from the values being recorded for the "clean" salt and rapidly turns chaotic. In addition, the resistivity values, which in clean salt are consistently above the reading range of the LWD equipment, drop to lower levels and exhibit substantial variance over shorter periods. In addition, one can detect the existence of inclusions from a seismic section. Inclusions are typically avoided whenever possible in a well design, since "dirty" salt may introduce a variety of unanticipated drilling problems (Chatar, Mohan, & Imler, 2010).

Significant shock and vibration events are often attributed to inclusions. Depending on the unique characteristics of each interval, dirty salts must be drilled at specific ROPs, to maximize the efficiency. The bit and the under-reamer may be drilling different formations when an inclusion is found, while simultaneously drilling and under-reaming with the same BHA. As a result, the bit may out-drill the reamer, rendering inefficient weight transfer to the reamer or vice versa. This could lead to shock and vibration levels that could harm BHA parts, necessitating a trip to replace them (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

Serious problems when drilling through dirty salt are related to wellbore instability and are common in every case where the stability of the wellbore is at risk. Nonetheless, when several instability issues occur simultaneously, such as packoffs[5], swelling rock masses, tight hole, pipe stuck, loss of circulation, well control issues, well ballooning, etc., handling of the situation gets extremely difficult. Moreover, when inclusions have a higher moisture content and/or a higher fraction of impurities, and the impurities are enclosed within the salt bodies, tight spots or stuck pipe events are more common (Chatar, Mohan, & Imler, 2010)

4.2.2.3 Sutures and/or inclusions

The case where, at least, two salt structures are joined to form a canopy is called a salt suture. Sometimes inclusions of different formations are trapped inside the salt (Amer, Dearing, & Jones, 2016). Clean salt has no pore-pressure properties since it has very low porosity and permeability. These inclusions may have anomalously high or subnormal pressures, depending on their original depth, the process that created them, and their lithology. Drilling through them can be extremely difficult because of kicks, circulation problems, and stuck pipe (Chatar et al., 2010).

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[5]**Pack off = Plugging of the wellbore in drill string's periphery. The usual reasons for that to event to take place are the not proper transport of cuttings and cavings on the wellbore. Apart from circulation loss, high pump pressures or even stuck pipe may be evented (https://glossary.slb.com/en/terms/p/pack_off).**

Kicks may be initiated in high-pressure zones (trapped pressure) inside salt masses which include shales or ruptured dolomite. These kicks are often small, though well control adjustments should take place, especially in the case of narrow operating drilling windows. Seams in salt can lead to large kicks and well abandonment, so when logs predict their existence, it is highly recommended to increase mud weight (approximately equal to overburden at that depth) and set a casing to counteract any influxes or creeping sediments (Wilson & Fredrich, 2005).

Inclusions in the salt may present a challenge for drilling operations for one more reason. That is the implications that could occur when drilling in sutures while under-reaming at the same time. Efficient drilling, ideally, requires different parameters for each formation. In cases such as when the bit goes through an inclusion, the under-reamer might be drilling a different formation. In such a case the drill bit may transfer the weight to the reamer, which will lead to shock and vibrations that could affect BHA components (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

Summarizing, sutures and inclusions may produce sudden increases/decreases in pressure causing kicks or circulation problems, stuck pipe, and excessive shock and vibrations to the BHA.

4.2.2.4 Salt creeping

Salt’s UCS (Unconfined Compressive Strength) is between 3,000 to 5,000 psi. Although its UCS is not that high, WOB and torque must be quite higher when it comes to drilling through salt, in contradiction to other sediments with similar UCSs. These measures are taken to deal with salt’s plasticity and creeping behavior (Chatar, Mohan, & Imler, 2010).

The environment of salt deposition determines its composition. Table 4-3 shows a number of salt types, along with their chemical formula, their relative mobility, and two of their physical properties.

Table 4-3. Properties and mobility of various types of salts (adopted from API RP 96) (Amer, Dearing, & Jones, 2016)

Salt	Chemical Formula	Relative Mobility	Squeezing Salt (Y/N)	Bulk Density (g/cm^3)
Bischofite	$MgCl_2 \cdot 6H_20$		Yes	1.54
Carnalite	$KCl, MgCl_2 \cdot 6H_20$		Yes	1.57
Sylvite	KCl		Yes	1.86
Halite	$NaCl$		No	2.04
Gypsum/Anhydrite	$CaSO_4 \cdot H_20$		No	2.35
Dolomite	$CaCO_3MgCO_3$		No	2.87

Due to their high moisture content, magnesium and potassium salts (such as bischofite and carnallite) are the most mobile, as seen by their chemical formula in Table 4-3. Less movable is halite, while anhydrite is immobile. Salts present high creep rates because of the significant amount of moisture content or the coexistence of clay impurities or shale interbedding. The likelihood of salt creep over time is indicated by pressure, temperature, and mineralogy. According to API RP 96, the creep rate of salt is also influenced by several other variables, such as depth, impurities, moisture, and local and regional geomechanical stresses (Amer, Dearing, & Jones, 2016).

Salt creeping magnitude depends on the temperature of the salt along with the difference between the isostatic pressure of the overburden and the hydrostatic pressure within the wellbore. Salt deforms slower in lower temperatures. Temperature is the most important factor when it comes to creeping. If temperature increases so do salt creep rates, while it should be noted that its increase is by far of greater magnitude for temperatures between 200 and 400 °F (Figure 4-5). For temperatures, even higher, salt turns nearly plastic and flows promptly, under differential pressure (Barker, Feland, & Tsao, 1994).

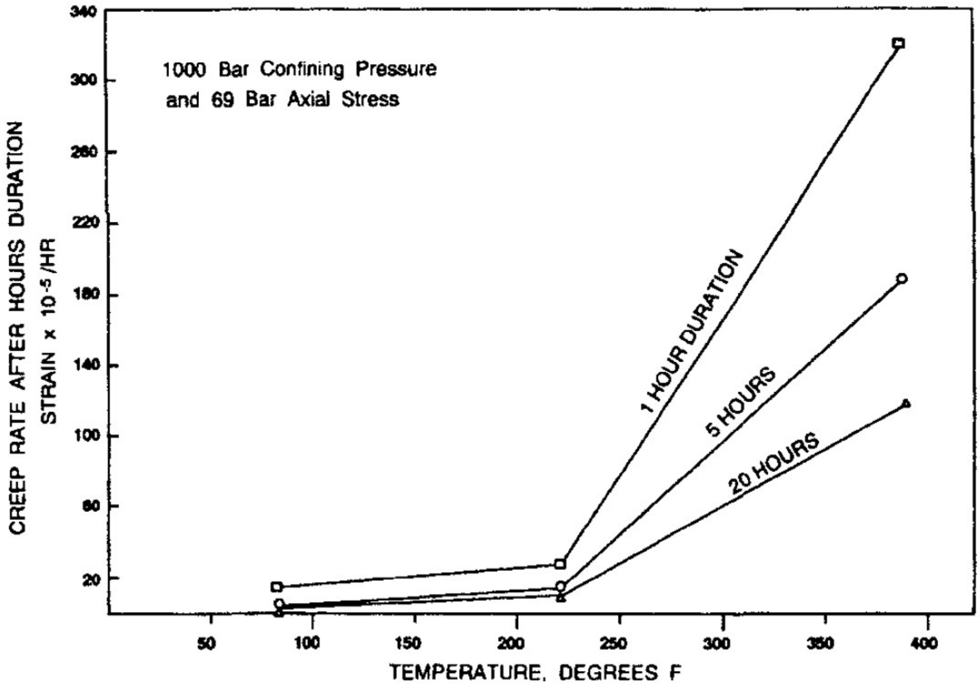


Figure4-5. Salt creep rate under temperature effect (Barker, Feland, & Tsao, 1994)

Salt creeping can be divided into two to three stages (Figure 4-6). Strain, in the first stage, initiates at a high rate and then constantly decreases, when confining pressures are below 725 psi. Salt deformation at a constant pace is what comes along with the second stage, while, the third stage, is characterized by an increase in strain rate until failure. If the confining pressures are over 725 psi, the third stage does not take place.

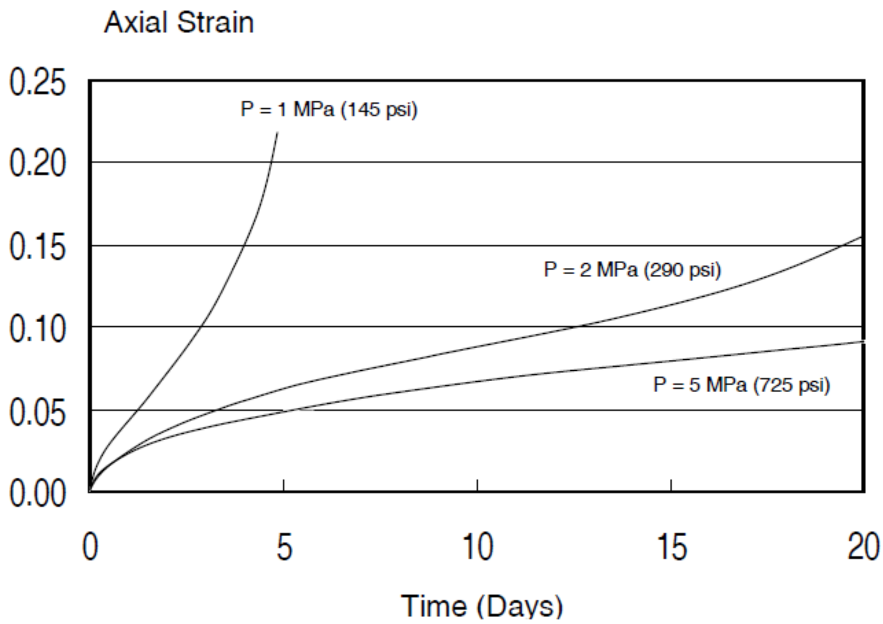


Figure 4-6. Salt creep rate at 25°C, under a stress difference of 25 MPa, for confining pressures of 145, 290, and 725 psi (Fossum & Fredrich, 2002).

Salt creeping affects mainly casing design, but also fluid selection, wellbore closure, and cementing. Regarding wellbore closure, the differential pressure between the formation and the pressure of the drilling mud, and higher temperatures can increase salt creeping, thus the rate of closure. Moreover, the rate of closure largely depends on the radius of the wellbore. Excessive torque and packoffs due to creeping constitute two of the major problems that we usually meet when it comes to salt drilling (Wilson & Fredrich, 2005).

Regarding the effect of salt creeping in casing collapse, it has been responsible for such incidents in several Gulf of Mexico wells. For instance, there was such an incident in which stresses were caused by creeping, three months after the setting of casing across a 15,000-ft [4,572-m] salt section. To avoid implications like these, drillers use a proper configuration of drilling muds, under-reaming the slip zone, and cementing practices that better accommodate stress distribution (Perez, et al., 2008).

4.2.2.5 Entrapped sediments in salt seams

High pore pressure and plasticity characterize the zones where sediments are trapped within the salt. Drilling through these zones requires mud weight to be high enough, to effectively counteract against squeezing effect of these sediments. Usually, appropriate mud weight produces hydrostatic pressure higher than 90% of the overburden isostatic pressure (Wilson & Fredrich, 2005).

4.2.2.6 Shear zones in salt

Consolidation of salt masses or their faulting may lead to the occurrence of shear zones. While commonly salts deform quite plastically over time, sustaining the spreading of subsalt faults, there is no proof, elicited by seismic logs, of disrupted base salts caused by the faulting of formations beneath them (Wilson & Fredrich, 2005). In any case, these shear zones typically carry the risk of deformable zones existing along with significant pressure.

4.2.2.7 Shock and vibration

Concerning shock and vibration acting on the BHA, it is the most difficult issue to handle while drilling through salt. These situations might lead to the failure of several drilling tools, thus imposing the need for fishing them and/or replacing them, as well, as other corrective procedures that will significantly increase the cost of drilling. Other reasons that might lead to shock and vibration issues are the wrong choice of unstable or excessively aggressive bits, or mismatched bits and reamers combinations while drilling different formations and creeping salts. Additionally, shock and vibration may be introduced when drilling through heterogeneous formations (salt entry and exit, dirty salts, inclusions, and suture zones). In such formation, it is often feasible that the bit will drill salt while the reamer, located up to 90 feet above the bit, drills an inclusion when they run simultaneously. That might lead to one tool drilling more quickly than the other, causing possibly poor inadequate weight transfer and eventually shocks and vibrations high enough to adversely affect the BHA (Perez, et al., 2008).

The type, magnitude, and frequency of shocks and vibrations imposed on the drill string depend on the formation’s coefficients of restitution and friction, combined with the shape and the diameter of the borehole and the well trajectory, as well as with the types of BHA components, their geometry, and mechanical properties, too. The energy spent on shocks and vibrations of the drill string is subtracted from the overall energy given to the drill string for drilling rock formations. In rare instances, due to shocks and vibrations, the drill string or one of its parts may catastrophically fail, resulting in NPT[6], after drilling operations are interrupted (Chatar, Mohan, & Imler, 2010).

Although estimations and modeling of possible socks and vibrations may be applied to offer recommendations for improving BHA design and bit-reamer suitability, often it is not enough to establish the perfect drilling specifications to reach a satisfying level of uneventful drilling procedure. Real-time data recording and analysis and modifying of WOB parameters under the observed shocks and/or vibrations (types and magnitude) is more helpful in these cases (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

4.2.2.8 Salt exit

Drilling through the base of the salt comes along with great risk as an outcome of salt migration and the ensuing perturbation of stresses in this area. While these risks are like those when entering the salt, the magnitude of the risks when exiting the salt is quite larger,

[6]NPT = Non-Productive Time - is the time when the drilling operations are interrupted for whatever reason. It is often used as a measure of the effectiveness of drilling operations and it is always presented as a percentage of idle time with respect to total operational time.

thus notably salt exiting procedures have been developed, mostly based on data extrapolated from the Gulf of Mexico offshore sites (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

Generally, it is preferred to exit the salt mass at a flat or barely angled site at the salt's base, while, if this is not feasible, it is preferred to maintain an exit angle, between the wellbore and the base of salt, as vertical as possible (Figure 4-7). Drilling engineers reduce ROP to roughly 40ft/h at some 400ft (122m) above the anticipated salt base, once the intended exit location has been identified and the well path has been determined. Not only that but they also monitor and make adjustments to maintain a steady state of torque, temperature at bottom hole, ECD[7], weight-on-bit (WOB), near-bit gamma-ray response, and vibration. Moreover, they may add lost circulation material (LCM) to the mud system and increase mud weight. Anticipating the possibility, the subsalt pore pressure is lower than that of the salt, cautious drilling engineers frequently prepare an LCM volume for usage.

When drilling engineers realize that the bit has reached the base of the salt, they pull the bit back up into the salt, to conduct a flow check, by evaluating the pit volumes and searching for any loss or gain of drilling fluids. This way, they understand if any kicks or loss of fluids occurred in the rubble zone just below the salt. Afterward, the drill string is lengthened by inserting non-standard lengths of drill pipes, to continue drilling under the salt mass until a depth equal to the length of a full stand of drill pipe, thus avoiding the need for a connection to be made before reaching that point.

[7]**ECD = Effective Circulating Density - is calculated as: d + P/(0.052*D), where d is the mud weight (ppg), P is the pressure drop in the annulus between depth D and surface (psi), and D is the true vertical depth (feet). The ECD is an important parameter in avoiding kicks and losses, particularly in wells that have a narrow drilling window (window between the fracture gradient and pore-pressure gradient).**

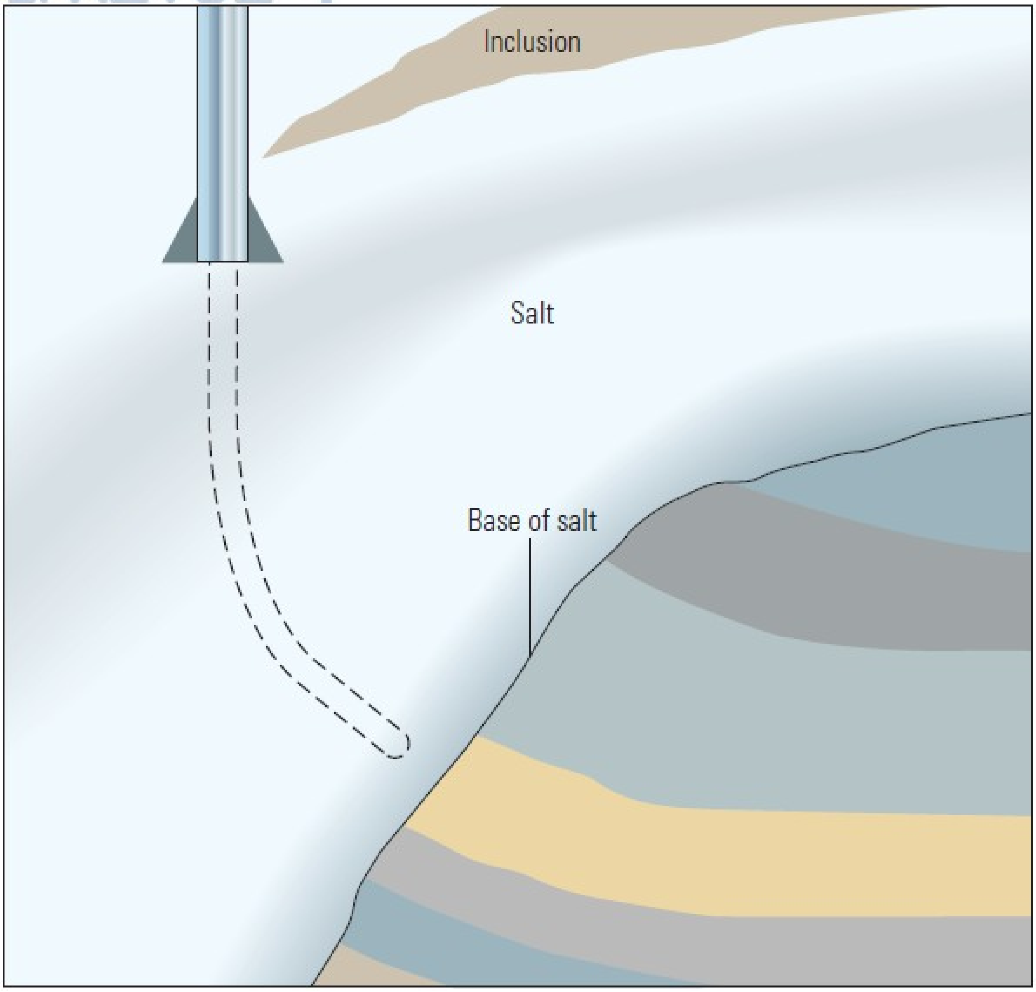


Figure 4-7. Exiting the salt strategy in the Gulf of Mexico (Perez, et al., 2008)

Drilling engineers continue to carefully monitor the fluid volumes in the pit by regularly pulling back the drill string into the salt and by circulating cuttings above the BHA. Drilling is then restarted in about 10 to 15 ft intervals with continuous monitoring of drilling parameters. Controlled drilling intervals are extended to 15 to 30ft (5 to 9m) between borehole checks if it has been determined that there are no issues with excessive pressure, circulation loss, or hole integrity issues. This continues until a length equal to two stands of pipes has been drilled or up to 300 ft [91 m] below the base of the salt (Perez, et al., 2008).

It should be noted that, depending on the particular well situation, the rig and operations teams frequently adapt these steps before the salt exit.

4.2.2.9 Summary of drilling through salt challenges

The challenges in drilling through salt are summarized in Table 4-4, in relation to the associated geomechanical hazards.

Table 4-4. Summary of drilling through challenges associated to relevant geomechanical hazards

Drilling challenges	**Geomechanical hazards**
Shock and vibration	- "Dirty" salt - Sutures and/or inclusions - Salt entry - Salt exit
Wellbore instability	- "Dirty" salt - Shear zone - Salt entry - Salt exit
Kicks and blowouts	- Sutures and/or inclusions - Salt exit
Circulations problems and/or loss	- "Dirty" salt - Sutures and/or inclusions - Salt entry
Stuck pipe	- "Dirty" salt - Sutures and/or inclusions
Casing design (collapse)	- Salt creeping
Wellbore closure	- Salt entry - "Dirty" salt - Sutures and/or inclusions - Salt creeping - Entrapped sediments
Cementing	- Salt creeping
Excessive torque & packoffs	- "Dirty" salt - Salt creeping

4.2.3 Drilling below salt (sub-salt)

As depicted in Figure 4-1, potential hazards during the drilling of the formations below salt are the following.

4.2.3.1 Rubble zone

If the effective stresses inflicted by salt or fluid movements are greater than what the nearby formations can withstand, rubble zones may occur in situ, depending on the geometry of the salt structure. Rubble zones may appear as a result of, first, higher pore pressures, even when total stresses may be relatively unaffected, which may promote rock failure by lowering the minimum effective stress required for rock breakdown. This phenomenon appears in the drill-out phase[8] of well drilling, where high pore pressure goes along with a small drilling window. Second, the existence of the salt structure can drastically alter the near-salt stresses, causing alterations in horizontal stresses or an increase in the shear stress that can cause the rock to break down in situ. It should be noted that if the mean total stress rises above far-field conditions, the resultant stress changes may also lead to higher pore pressure (Wilson & Fredrich, 2005).

Rubble zones have been examined in numerous technical papers and their definition could otherwise be “unknown geologic zones”. Flipping through scientific pages, the sediments next to salt are frequently referred to as smeared, shear, drag, gouge, brecciated or rubble zones, but practically they are distinguished into two major categories (Saleh, Williams, & Rizvi, 2013):

1. The first one is the ***“shear zone”***, which is made up of sediments tangent to the salt formation. These sediments are highly plasticized (behaving like "gumbo"), “smeared” or “sheared”, and may be at or close to the "pore collapse" state, as a result of significant shearing forces. A narrow drilling window is the outcome of such effects. At a stress condition close to the mean, the sediments may have high pore pressure. Wellbore instability issues occur due to the plasticity of the deformed sediments inside the wellbore, although kicks might not emerge. To stabilize the wellbore, the mud weight should be near the fracture gradient (93-95% of the overburden gradient may be needed), or else caving occurs resulting in stuck pipe, hole packoff, or hole enlargement.

2. The second one is the ***“rubble/brecciated zone”***, consisting of competent, older, fractured sediments that were affected by salt migration. This quite fractured zone can lead to the loss of circulation fluids, but these sediments are less impacted by the stress regime of salt, so pore collapse is not an issue for them.

Some common problems related to rubble zones are listed below:

1. The trickiest thing about rubble zones is the difficulty to determine the pore pressure regime at the base of the salt. It can present low pressures and can produce losses, or it

[8] **Drill-out phase: to dig out the remaining cement in the wellbore's bottom after the casing has been set and cemented in place, to drill deeper.**

can present high pressures and can produce a kick. So, there is a lot of uncertainty about the pressure regime within a rubble zone.

2. Unstable rubble zones may cause hole collapse, packoff, and increased torque. Fast drilling through this area can cause drill string or BHA to become stuck.

Rubble zones, near salt, usually come with shales that are highly reactive and are enclosed in unconsolidated sands. They might be over-pressured at the entry point due to a potential gas pocket under salt and under-pressure below this point. So apart from well control problems and lost circulation issues, wellbore could be eroded within the shales on top of and beneath the salt.

Rubble zones can be detected if drilling parameters are systematically monitored. For example, when a pressure relapse is observed this may result in an abrupt loss of circulation. If, while drilling enters an over-pressured zone, kicks may take place (Amer, Dearing, & Jones, 2016).

Of all the hazards mentioned above, the loss of circulation is the most common to happen within the rubble zone below the salt, and it is the costliest too. Well control issues appear more rarely, around 20% of the time, while cementing failures may cause problems to future well development. These issues usually take place because of the small amount of data, regarding the fracture gradient and the pore pressure inside the rubble zone.

The drilling window in which fracture pressure is quite close to pore pressure is the main reason why issues generally occur when drilling rubble zones beneath salt bodies. To avoid them, data need to be extrapolated as much as possible from logging data and real-time monitoring data while drilling. The presence of highly pressured deformed zones beneath the salt base, which overlies younger and lower pressured strata, makes rubble zone characterization hazardous. The sheared zones next to the salt face, are separated from the surrounding formations mostly by reversed fault zones. Loss of circulation may occur just beneath the shear zones as a result of the existence of porous, naturally fractured formations with lower pore pressures, while kicks could take place due to many fluid migration pathways. Salt position and the stress regime of its surrounding formations, so as their lithification state, are quite connected to the uncertainty of fracture pressure prediction.

Narrow drilling margins usually come along with the ballooning phenomenon, which has to do with loss of circulation due to induced fractures opening and closing. If this phenomenon is detected on time, while drilling, huge mud loss could be avoided by increasing mud weight (Saleh, Williams, & Rizvi, 2013).

4.2.3.2 Undetected salt flanks of elevated pore pressure

Zones of extremely high trapped pore pressure may develop around the margin of the salt structure as a result of confined dewatering paths or the formation of structural highs. Outgrowing “wings” of salt at the edges of the salt structure are exceptionally competent seals for hydrocarbons but also can produce significant pore pressure differences from side to side. Due to the typically low seismic resolution close to salt, it may also be quite challenging to distinguish these structures via seismic before drilling (Wilson & Fredrich, 2005).

4.2.3.3 Occurrence of tarry bitumen/asphalt bands

Pockets of movable tar or bitumen that frequently appear beneath the salt and along faults and/or welds are quite challenging when drilling through them because those are viscous materials that contain more than 85% asphaltene. A significant number of risks come along with these mobile or active tars, which usually appear layered along a subsalt fault, reaching 10-100ft in thickness (Figure 4-8). Keeping the borehole open when casings are to be placed, is quite difficult even if under reamers are used since tar is plugging the wellbore (Perez, et al., 2008).

The most important risks, associated with tars existence are (Perez, et al., 2008):

- Packoffs behind the BHA, causing circulation loss
- Borehole swabbing[9]
- BHA components’ damage due to shocks and/or vibrations

[9] **Swabbing = Pressure reduction in a wellbore by moving pipe, wireline tools or rubber-cupped seals up the wellbore. If the pressure is reduced sufficiently, reservoir fluids may flow into the wellbore and towards the surface. Swabbing is generally considered harmful in drilling operations, because it can lead to kicks and wellbore stability problems (https://glossary.slb.com/en/terms/s/swab).**

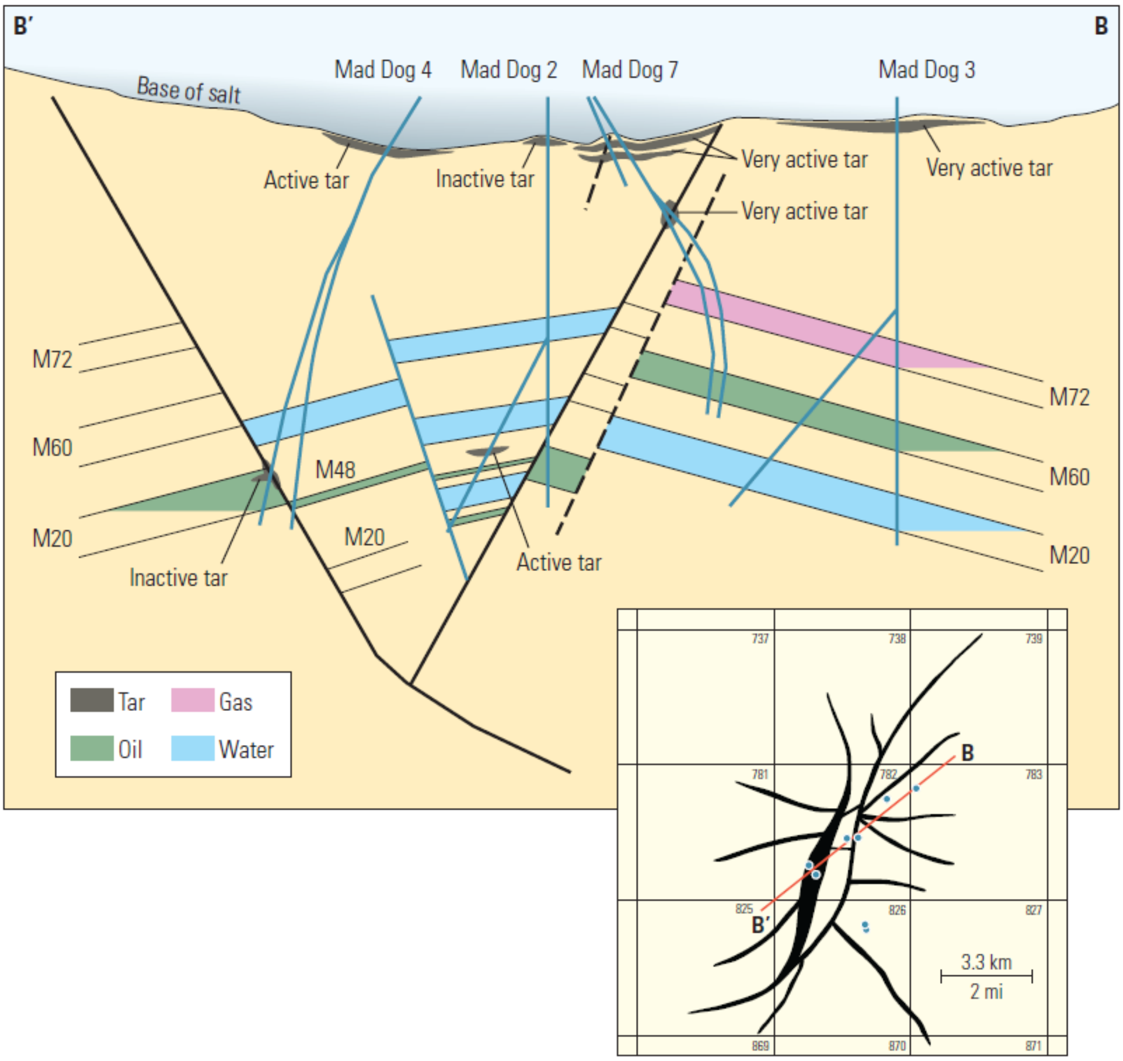


Figure 4-8. Example of mobile tar deposits below the base of the salt in GOM (Perez, et al., 2008)

- Logging tools coating
- Stuck tools due to borehole bridging
- Casing procedure issue, like casing sticking high or extra lag time
- Need for more trips to clean tar in casing or, riser too
- Surface issues

When tar appears in a wellbore, the main task is to manage to retain the borehole as wide as needed. Casing usually holds up on tars that tend to plug the hole, entirely. Common tars usually move through fractures, upwards, due to salt migration, making zones characterized by uncertain pore stresses. When tars are thick and abundant, we assume that tar volcanism took place, a phenomenon according to which tar masses flowed upon the bottom of the sea and were buried afterward by the overlying sediment and salt masses. Tar layers are found in deep-water in the Gulf of Mexico, which are rich in asphaltenes, as well as in Canada and Venezuela but of different origins, which here are uncemented sands saturated by biodegraded heavy oils (Wilson & Fredrich, 2005).

Prediction of tar is impossible through the surface seismic data acquisition stage because it does not show up in them. The factors that matter, when dealing with tar are the kind of tar (solid vs. mobile), its location (fault/fracture fill vs. bedded tar), and the total thickness of the tar sections encountered in the borehole. Two main recommendations are made to minimize the issues that tar introduces: avoiding tars entirely or operating drilling procedures as quickly as possible. To avoid tar, an exit target box must be determined at the salt's base before drilling it, where a kickoff might be needed within the salt to drill through the target (provided that the location of tar can be correctly determined before drilling commence). Maximizing the drilling speed implies that positive displacement mud motors (PDMs) are not suitable for drilling through salt and tar, because it has been noted that ROP in salt with PDMs is less than half the ROP with conventional rotary drilling. It should also be noted that keeping the BHA and the drill string rotating, is quite practical for avoiding stuck pipe events within the tar (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

4.2.3.4 Significant pressure decline below salt

To prevent time-dependent salt creep in the well section within the salt, heavy mud weights may need to be used to exit the salt and drill the next sub-salt section up to the next casing setting depth. When formations beneath the salt are permeable, a substantial subsalt decrease in pore pressure may occur (whether predicted or not) that could provoke a differential sticking problem. If the decreasing pore pressure is not correctly identified during real-time monitoring procedures, fracture gradients will also decrease, causing circulation loss. The best course of action for drilling engineers in these circumstances is to set the casing before leaving the salt (Wilson & Fredrich, 2005).

4.2.3.5 Overturned sediments near salt

Salt masses that considerably migrate laterally can cause composite deformation of the sediments near salt. During this process, near-salt sediments may end up extremely overturned, faulted, and severely fractured. Rubble zones might appear in such cases, along with loss of circulation and wellbore instability due to excessive stresses. Geomechanically speaking, it could be quite helpful to identify such features on seismic, to enter in these zones with extreme caution (Wilson & Fredrich, 2005).

4.2.3.6 Uncertainty in the depth of the salt base

Poor seismic resolution below salt leads to mistrust of seismic velocities in these areas, which goes along with mistrust of the corresponding pore pressures. This is probably the greatest difficulty in designing the well sections below the salt, as an error of 12% in the seismic velocity can result in a deviation of 1.5 ppg in the estimated pore pressure. Seismic velocity mistrust might also lead to a wrong forecast of the salt base depth, hence causing mistrust in the selection of the setting depth of well casings (Wilson & Fredrich, 2005).

4.2.3.7 Plasticized sediments below salt

In areas with a significant relative movement among the base of the salt and the surrounding formations, strong lateral shear may develop producing a “gouge” zone of significantly plasticized sediments. Drilling through these zones presents a significant challenge: if underbalanced drilling is applied (insufficient mud weight to counterbalance the very high pore pressures, which are nearly as high as overburden), plasticized sediments cripple into the wellbore at a reasonably quick rate, leading to stuck pipe and tight hole problems. The tremendous loads imposed by these formations have the potential to cause even casing deformation (Wilson & Fredrich, 2005).

4.2.3.8 Summary of sub-salt drilling challenges

The challenges in drilling formations below salt are summarized in Table 4-5, in relation to the associated geomechanical hazards.

Table 4-5. Summary of sub-salt drilling challenges associated with relevant geomechanical hazards

Drilling challenges	**Geomechanical hazards**
Narrow drilling window	- Rubble zones - Significant pressure decline - Overturned sediments
Uncertainty in pore pressure regime	- Rubble zones

Drilling challenges	**Geomechanical hazards**
	- Undetected salt flanks
Wellbore instability (collapse, cavings, enlargement)	- Rubble zones - Overturned sediments
Packoffs & increased torque	- Rubble zones - Tars
Kicks	- Rubble zones - Undetected salt flanks
Circulation loss/Well control	- Rubble zones - Significant pressure decline
Borehole swabbing	- Tars
Stuck pipe	- Rubble zones - Tars - Plasticized sediments
BHA damage due to shock & vibration	- Tars
Casing setting issues	- Tars - Uncertainty in the depth of the salt's base
Wellbore closure	- Tars
Cementing	- Rubble zones

4.3 Summary of major drilling problems associated with drilling around and through salt

Table 4-6 summarizes the most important of the drilling problems mentioned above in relation to the geomechanical hazards presented around and through salt formations.

	Geomechanical hazards	Drilling problems																				
		Wellbore instability	Washouts	Circulation loss	Kick & Blowout	Tight hole / Gumbo shale	Gas-cut drilling mud	Shock & Vibration	Narrow drilling window	Over-pressure	Borehole closure	Differential sticking	Casing setting depth	Stuck pipe	Casing loading /	Pack offs	Swelling rock	Well control	Reactive shale	Excessive torque	Uncertainty in pore pressure regime	Cementing
Supra	Tectonically unstable toe-thrusts	Likely																				
	Highly fractured sediments			Considerable																		
	Over-pressured sediments					Considerable																
	Shallow gas pockets	Intense		Intense	Intense		Considerable			Likely												
	Salt entry		Likely																			
Through	Salt entry	Likely		Considerable		Considerable		Considerable		Considerable												
	"Dirty salt"	Intense		Likely		Considerable		Considerable						Likely		Likely	Likely	Likely				
	Sutures / inclusions			Considerable	Considerable	Considerable		Considerable	Likely					Considerable								
	Salt creeping					Considerable									Intense	Intense				Intense		Considerable
	Entrapped sediments					Likely																
	Shear zones	Likely							Considerable													
	Salt exit	Likely			Likely			Considerable		Considerable												
Sub	Rubble zone	Considerable		Intense	Considerable				Intense					Likely		Considerable	Intense		Considerable	Considerable	Considerable	Considerable
	Undetected salt flanks of elevated pore pressure				Considerable					Considerable											Considerable	
	Tar / asphalt					Considerable					Intense		Likely	Likely		Considerable	Considerable					
	Significant pressure decline			Considerable					Intense		Considerable	Considerable						Considerable				
	Overturned sediments	Likely							Likely			Likely										
	Uncertainty in the salt base												Likely									
	Plasticized sediments					Likely								Likely	Likely							

Table 4-6. Summary of major drilling problems associated with drilling around and through salt

Legend:

Intense	
Considerable	
Likely	

CHAPTER 5. ENABLING AND EMERGING TECHNOLOGIES IN SALT DRILLING

5.1 Aspects of drilling operations

In this chapter, some aspects of drilling operations, that have to do with drilling through and around salt will be discussed. These briefly are:

- Well design (subsalt imaging, well verticality/inclination, hydraulics program – mud weight)
- Drilling operations (drilling rigs, Rotary Steerable Systems-RSSs, riserless drilling, Bottom Hole Assembly-BHA design, drilling bits & under-reamers, Rate of Penetration-ROP, casing design, cementing)
- Well control (mud system, wellbore stability)
- Other aspects (real-time monitoring, MWD / LWD tools, critical personnel, shore support for offshore wells)

According to API recommended practices (API RP 96), the majority of the salt drilling hazards can be reduced by using the following best practices (Amer, Dearing, & Jones, 2016):

- Keep the wellbore in gauge (uniform diameter and annular opening).
- Employ appropriate drilling fluids that minimize or avoid salt leaching.
- When drilling through salt, maintain higher mud weights as a percentage of the overburden gradient.
- Increase annular clearance by using enlargement tools and/or techniques when drilling through unstable salts.
- Estimate salt creeping rates for mobile salt in well conditions and devise mitigating measures.

5.2 Well design

The offset information from the previous wells drilled has been extremely helpful in designing the wells to be drilled. Drilling engineers work together with geomechanics specialists to understand the impact of the fracture and the pore pressure gradients on the drilling window. Accurate 3D modeling, by using finite element analysis, is used to examine salt bodies and their surroundings, while traditional 1D mechanical earth modeling often breaks down in this environment. Pore pressures in these intervals are hard to predict even when advanced modeling is used, but the advances in seismic technology allow us to interpret data acquired from the surface, and analyzing the results allows us to determine when the wellbore will be getting closer to the base of the salt. At-bit measurements, particularly at-the-bit gamma-ray measurements, can also be used to examine what is happening ahead of the bit. In such cased drilling must be temporarily slowed down while the pore pressure regime is established, along with annular pressure measurements, and the well can be drilled ahead by adjusting the mud weight accordingly.

When it comes to drilling around salts, a considerable number of risks need to be taken into account and properly assessed (such as wellbore instability, acute stress changes, gas-cut muds, circulation losses, abrupt pressure increase, etc.). Thereafter, these risks can be addressed with the following technics (Dusseault, Maury, Sanfilippo, & Santarelli, 2004):

- Adjust the well trajectory to pass over the salt or at a certain distance from the dome structure to avoid hazardous zones.
- Temperature control of drilling fluids (by heating or cooling them) depending on each particular case.
- Adjust the circulation rate of the drilling fluid to control Equivalent Circulation Density (ECD), rate of heating/cooling, as well as the flushing of gas through the mud.
- Keep significant levels of Loss Circulation Materials (LCM) in drilling mud, especially for drilling through fractured shale, when traversing depleted zones, as well as for dealing with low Leak-Off Test (LOT) at the casing shoe.
- Control of Rate of Penetration (ROP), e.g. in reactive shale increase the ROP or decrease it when using water-based muds to control gas cutting in sections of a well with large diameters within fractured shales.

Generally, to drill efficiently through salt, while avoiding hazards, there must be an understanding of pressures and material behavior, through selected models that capture the essential elements of what is happening in the wellbore, such as salt creeping, heat flow, temperature sensitivity of drilling fluids, etc. (Dusseault, Maury, Sanfilippo, & Santarelli, 2004). Some tactics for drilling through salt are:

- Before drilling, rigorous estimation of temperature and pore pressure must be implemented, to promptly calculate hole closure rate and the level of underbalanced drilling. Salt stresses can be considered isotropic and equal to the pore pressure, due to their viscous behavior.
- Set the casing shoe in salt as deeply as possible near the top of salt, to prevent an extra casing string, when drilling through thick salt bodies. This tactic is commonly used offshore.
- Use of PDC bits and drill as quickly as possible sections of significant length through salt structures, to handle salt creeping. Moreover, vibration management devices must be used when drilling non-salt intervals and suture zones in salt.
- Assess the closure rate due to salt creeping most likely to be present under the worst circumstances, within a range of uncertainty. Around 4-5% per day is usually an appropriate closure rate to consider.
- Use of a drilling fluid density that will prevent creep closure to exceed the above-considered rate in the area that creeps the fastest, which is typically at the bottom of the hole, where the salt is hottest and the underbalanced (pore pressure – fracture pressure) is greatest.
- Drilling mud density can always be changed to lower closure rates, but there are restrictions due to possible fracture problems at the casing shoe within the salt. However, compared to porous formations, the effects of such fractures are less severe.
- Choice of OBM or WBM, depending on the situation. In any case, the aqueous phase should be kept saturated. Designing undersaturated WBM to prevent closure and using additives to change salt dissolving rates don't seem to be very useful.
- Installation of back reamers at the top of the BHA to avoid closure and BHA sticking is a common tactic to deal with encountered non-NaCl formations that have a higher salt creep potential.
- Employment of a stabilizer and an under reamer above rotary steerable systems, when rapidly drilling a long section through salt, helps achieve high ROPs with no

considerable deviations. This tactic comes along with trajectory corrections and MWD technology.

- Accurate calibration of creep models will assist direct additional holes in the same salt portion. Closure data collected with acoustic calipers during trips will aid in this process.
- Since salt creep rate heavily depends on temperature, cooling the drilling fluid can lower the closure rate. Cooling might be utilized right before the casing setting, such that the hole can be left for ten to fifteen hours without being overly closed.
- Set casing a few meters after escaping salt while drilling through a substantial layer of salt to minimize the risk of hydraulic fracturing or blowouts by placing the shoe in sediments.
- Placement of casing after exiting a thick layer of salt so that the casing shoe is set in matrix-supported formations where permeability may be inhibited by salt, to minimize the possibility of hydraulic fracturing and blowout events.
- Poor hole profiles or the interfaces between salt and other sediments in salt sequences can create casing strain and result in point stresses on the casing due to wellbore closure. The use of high-density types of cement prevents casing distress and, additionally, a sturdy cement sheath and steel casing work to prevent creep implications.

5.2.1 Sub-salt imaging

Geoscientists have various difficulties when trying to conduct seismic imaging through thick salt masses. The remarkable contrast in seismic velocities of salt and its surroundings may lead to misinterpretations of imaged structures with common time migration techniques. This makes it far more challenging for drillers to find their intended drilling targets, such as targets in the base of the salt, because crucial horizons may show up on seismic images hundreds of feet away from where they actually are (Figure 5-1).

This issue has been partially solved by 3-D pre-stack depth imaging, which improved the seismic image and significantly decreased the inaccuracies of time-migrated data. However, due to the constraints of the time-depth transforms being employed to address difficulties with formation anisotropy, there are still a lot of unknowns. The sub-salt image is being further refined using new techniques, which dramatically lower drilling risks. The predrill positional accuracy of salt inclusions, the base of salt (and dips), the ability to better picture rubble

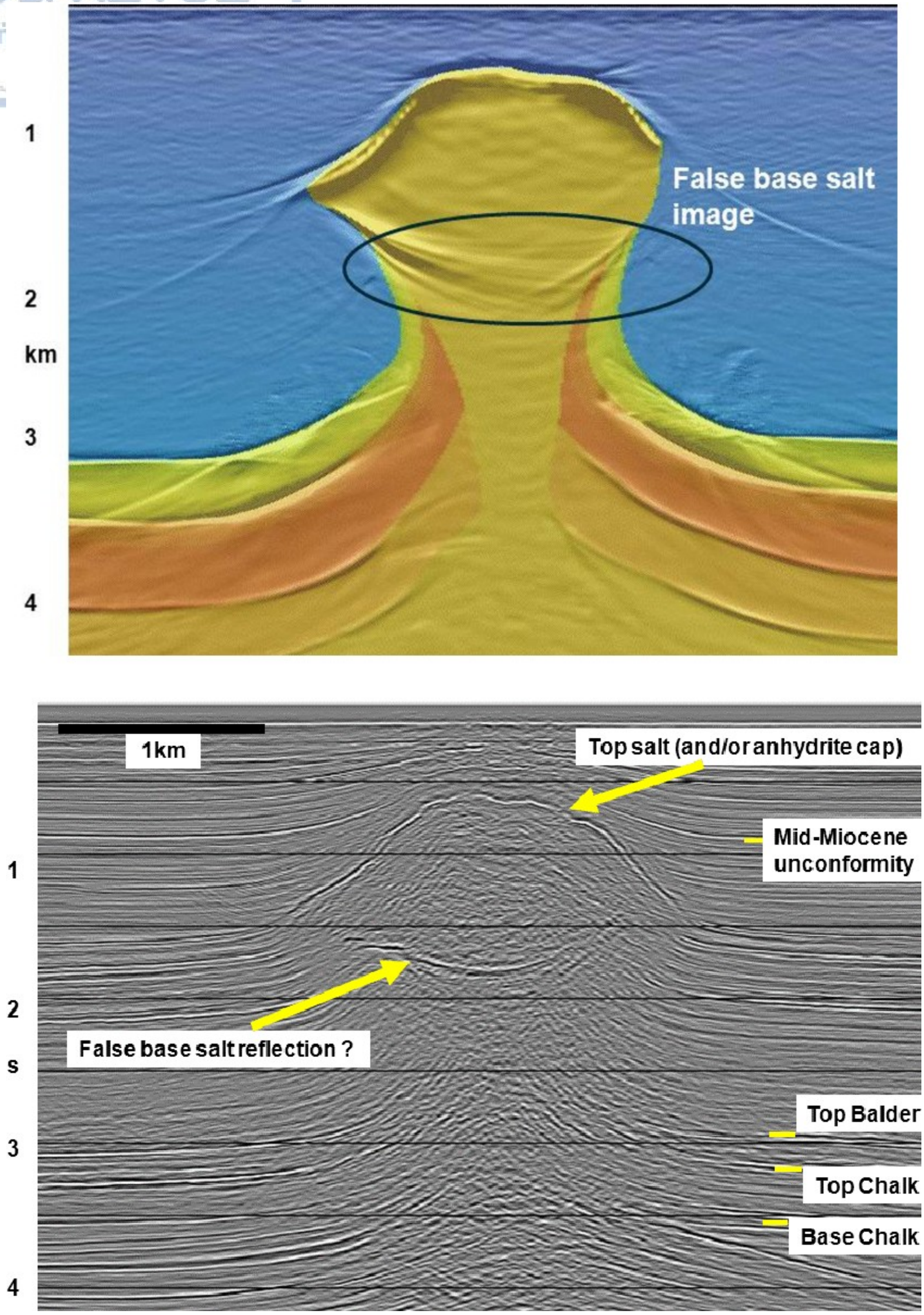


Figure 5-1. Results of synthetic modeling of a salt body without a base salt. The picture above depicts an incorrect base salt reflection. The picture below displays the relevant real data outcome (Jones & Davison, 2015)

zones and the reduction of pore pressure uncertainty below salt will all benefit from these enhancements (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

5.2.2 Well verticality

With a few exceptions, such as vibrations at entry and exits and well non-verticality, which can cause wellbore instability, salt is rather easy to drill due to its flexibility. The ratio of overburden of mud weight to salt is the single biggest issue for drilling salt. It has been repeatedly demonstrated the necessity of maintaining 85% to 95% overburden to stop drilling vibrations and stick slides. Drill string vibrations can be modeled using finite element analysis, and equipment adjustments[10] can be made to reduce drilling disturbance and raise ROP.

The behavior of the formations is altered by pressure in and around salt, leading to salt creep, over- or under-pressured zones, and a highly faulted environment. Due to the presence of shale or anhydrite inclusions, maintaining verticality while drilling salt has always been difficult. The process of maintaining wellbore verticality comes along with proper bit selection synchronized with a matching reamer to control vibrations and wellbore stability. In addition, real-time monitoring and optimization help in efficiently drilling, while a rotary steerable system in hold mode can also be used.

5.3 Drilling operations

Fit-for-purpose technological advancements, some of which have limited applications, have helped to improve drilling through salt. Rigs, rotary steerable systems (RSS), bits, under-reamers, sub-salt imaging, real-time monitoring, and MWD/LWD are a few examples of technology enablers. These are presented below, along with other significant improvements.

5.3.1 Rigs

Nowadays, we experience the 7th generation of drilling rigs, while considerable improvements in rigs suitable for salt drilling started since the 5th generation rigs (Figure 5-2). These rigs are capable of producing more torque at the higher rotating speeds required for salt drilling. Hydraulics improvements have been made by greater pressure pumps and larger drill strings which was made possible by increasing the derrick’s capacity. Also,

[10]Before drilling starts, drilling engineers must be sure that the reamer, the drill string and the bit are matched, as bits and reamers are commonly responsible for excitation forces emergence, while drilling.

enhanced hook ratings provide the ability to run longer, heavier casing strings through thick layers of salt. Storage capacities are magnified which is helpful when using the pump and dump method to drill riserless into the salt with salt-saturated WBM, while higher volumes of cement are needed too in conjunction with the larger holes drilled (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

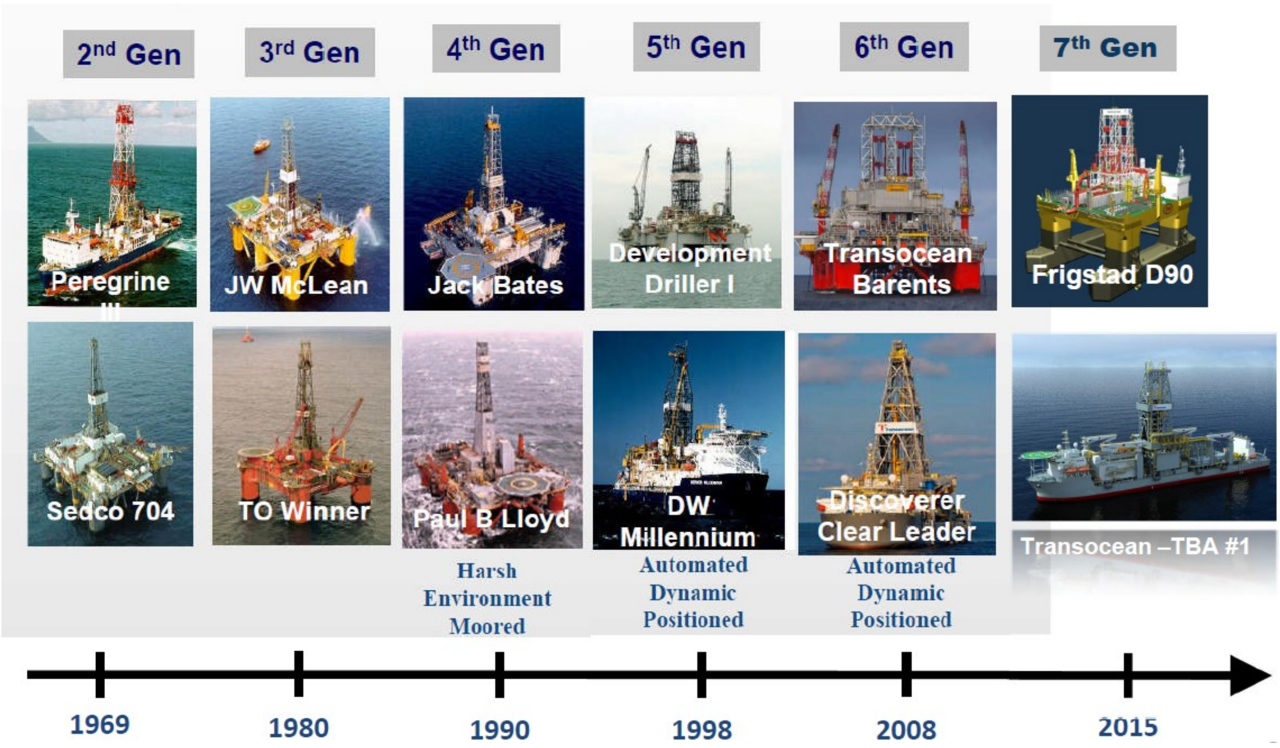


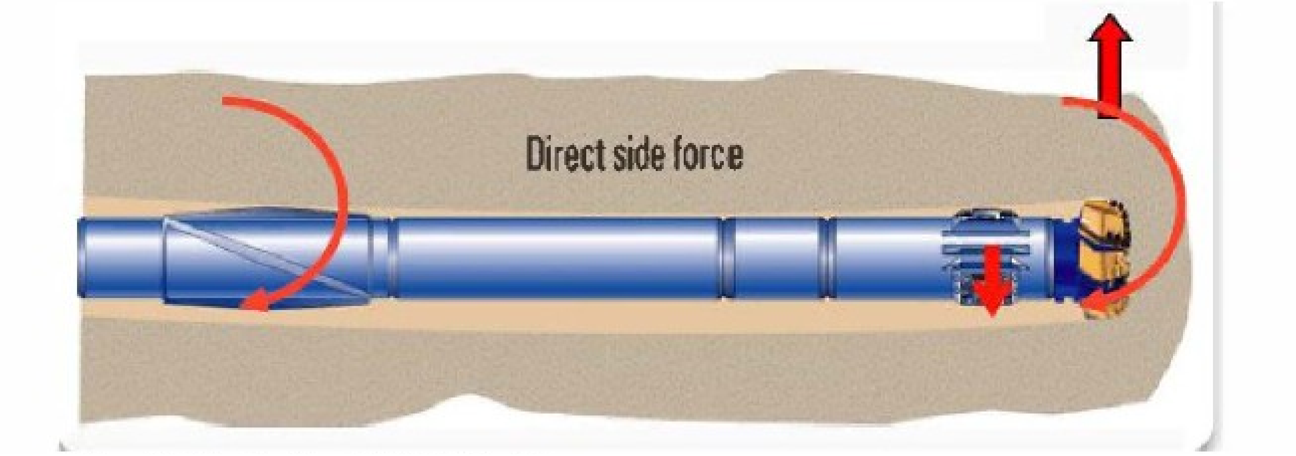
Figure 5-2. Evolution of offshore drilling rigs (Rennie, 2013)

5.3.2 Rotary Steerable Systems (RSS)

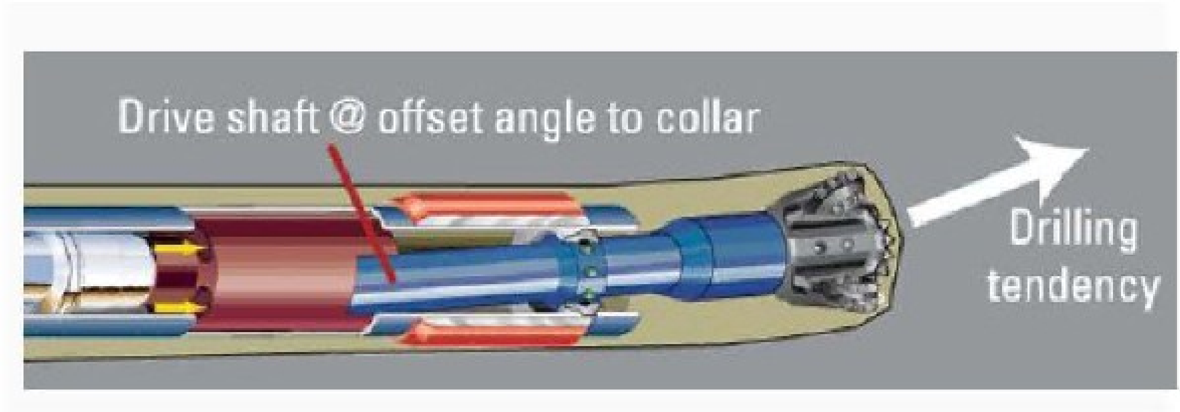
Drilling salt with positive displacement mud motors has proved to be ineffective and not successful, due to the sliding/rotating mechanism they use, especially in directed applications. On the contrary drilling salt with RSS can result in an ROP increase, while the wellbores are smoother with more reliable doglegs have been demonstrated. Nowadays, as well drilling operations became more demanding, and RSS are manufactured larger (up to 26 inches) and operate quite successfully in salt. Also, the rotary steerable drilling technology combines well with the rigs' enhanced capacity. Because deep-water operations are so expensive, rotary steerable systems are a practical choice for salt drilling (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

For a project to be considered successful as an investment, development costs should be as low as possible. This can be accomplished if drilling days do not exceed the drilling plan by limiting drill centers per field. For this to happen, it can be necessary to drill extended-reach development wells. A shallow kickoff point—the point at which the well starts to deviate from the vertical—is frequently required to prevent excessive angles and doglegs, which can seriously complicate and delay casing and completion operations. It should be noted that shallow kickoffs necessitate directional drilling in the top sections of the wellbore which have relatively larger diameters. Mud motors have traditionally been used for this, which, however, frequently produce poorly penetrating rates of penetration (ROP) and extremely convoluted wellbores. Use of a larger diameter (26-in.) RSS for the shallow kickoff decreased drilling time by 63% when compared to conventional mud motors used in the same sections of neighboring wells.

Issues like inclusions, salt creeping, or tars are prevented thanks to RSS tools without affecting the quality of boreholes. Two are the main types of RSS tools (Figure 5-3): The “push the bit” type, which pushes mud-actuated pads against the borehole walls, and, as a result, the bottom hole assembly and the well trajectory are compelled to travel in the opposite direction (Figure 5-3a). The “point the bit” type bends a flexible shaft linked to the bit to alter the bit tool-face angle and subsequently the well direction (Figure 5-3b). Many times RSS tools are used to deal with build-walk tendencies in vertical drilling. In some cases, low-speed motors with high torque are used with RSS tools, making a “powered RSS”, which is quite an efficient system where the rotational speed of the drill string can be lowered while torque is transferred immediately to the bit (Perez, et al., 2008).



(a)



(b)

Figure 5-3. (a) "Push-the-bit" RSS and (b) "Point-the-bit" RSS (Park, Kim, Park, & Myung, 2013)

5.3.3 BHA design – directional control – verticality

Regardless of the type of drill bit used to drill salt, salt has also been drilled using eccentric or bi-centered bits, as well as side-cutting reamers or mills placed above the bit. These bits and assemblies enable the wellbore radius to be decreased from the drilled radius, preventing under-gauge holes.

Figure 5-4. PBL sub (DSI FZE, 2022)

Long salt sections can be challenging to drill since the wellbore radius is typically either expanded or under-gauged, making it challenging to maintain directional control. When under-saturated salt mud is used hole enlargement happens often, especially on the low side of the wellbore, making it difficult to maintain the wellbore angle needed. When entering a salt dome with under-saturated salt mud and a minor wellbore angle, this factor can be extremely noticeable. The wellbore will be able to drop to vertical quickly as a result of the hole enlargement due to the dissolution of salt, which, on the other hand, will result in a major dogleg and ledges that can be quite problematic (Barker, Feland, & Tsao, 1994).

In any case, effective modeling and well-engineered BHA designs give satisfactory first estimations for the operational efficiency of each bottom-hole assembly.

When the well being drilled reaches the point to enter salt, drilling engineers must cope with the major possibility of washouts. A PBL sub can act as a precaution to stop salt washout at the entry when it is positioned much higher up in the drill string so that it will remain above the top of the salt at the casing point. This sub is designed to bypass a portion of the mudflow, preserving the salt's integrity in the process (Figure 5-4). PBL comes from the name of its inventor (Paul B Lee) and it is a tool adopted on a drill pipe that enables the pumping of aggressive LCM pills and increases circulating rates during drilling operations.

5.3.4 Drill bits

Although traditional rock bits have shown to be useful in salt drilling, the use of aggressive PDC bits has produced typically higher penetration rates, aiding in the quickest possible passage through salt. The built-in stability of PDC bits is what makes them the most preferable for directional drilling in salt, also. However, aggressive bits with 6 blades or fewer and 19mm cutters can produce, in general, drilling-related shocks that can cause early tool failure or, in the worst-case scenario, the separation of one of the BHA components (Figure 5-5a). Therefore, it is preferred to choose less aggressive bits. A general guideline is a bit to have more than 7 blades and 13mm cutters more or less (16mm cutters for bits with a diameter higher than 18-in) (Figure 5-5b). Bits should also be compatible with concentric reaming tools, for greater results, while it should be noted that the cutter should not out-drill the reamer. In the past years, there is a demand for large PDC bits (with a diameter of 18 1/8 up to 26 in) to be used in the deep-water fields of the Mexican Gulf. To maintain large PDC bits stabilized, good gauge length is essential, as experience has proven (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

(a)

[(https://www.alibaba.com/product-detail/Aggressive-Borehole-Drilling-5-Blades-Steel_60764662420.html)](https://www.alibaba.com/product-detail/Aggressive-Borehole-Drilling-5-Blades-Steel_60764662420.html)

(b)

[(https://cdhlfco.en.made-in-china.com/product/TjEmQZMAXykF/China-11-5-8-8-Blade-13mm-Cutter-Steel-Body-PDC-Drill-Bit-for-Oil-Gas-Drilling.html)](https://cdhlfco.en.made-in-china.com/product/TjEmQZMAXykF/China-11-5-8-8-Blade-13mm-Cutter-Steel-Body-PDC-Drill-Bit-for-Oil-Gas-Drilling.html)

Figure 5-5. (a) Aggressive PDC bit with 5 blades and 119mm cutters, and (b) a less aggressive PDC bit with 8 blades and 13 cutters, both suitable for salt drilling

More specifically, PDC bits are more effective in cutting through salt because of their shearing action and because they also require less WOB (Figure 5-6 top left). Given the homogenous nature of the salt and its excellent durability, lengthy salt sections can be drilled in a single run before the casing is set. PDC bits' specific design parameters specify how hard these bits attack the formation (Figure 5-6 top right and bottom right).

BHA's directional tendency and ROP are massively affected by bit selection because the wrong choice of bit can lead to shocks, vibrations, or stick pipe events. Bits are selected mostly in relation to the knowledge acquired from the local field of interest (Perez, 2008).

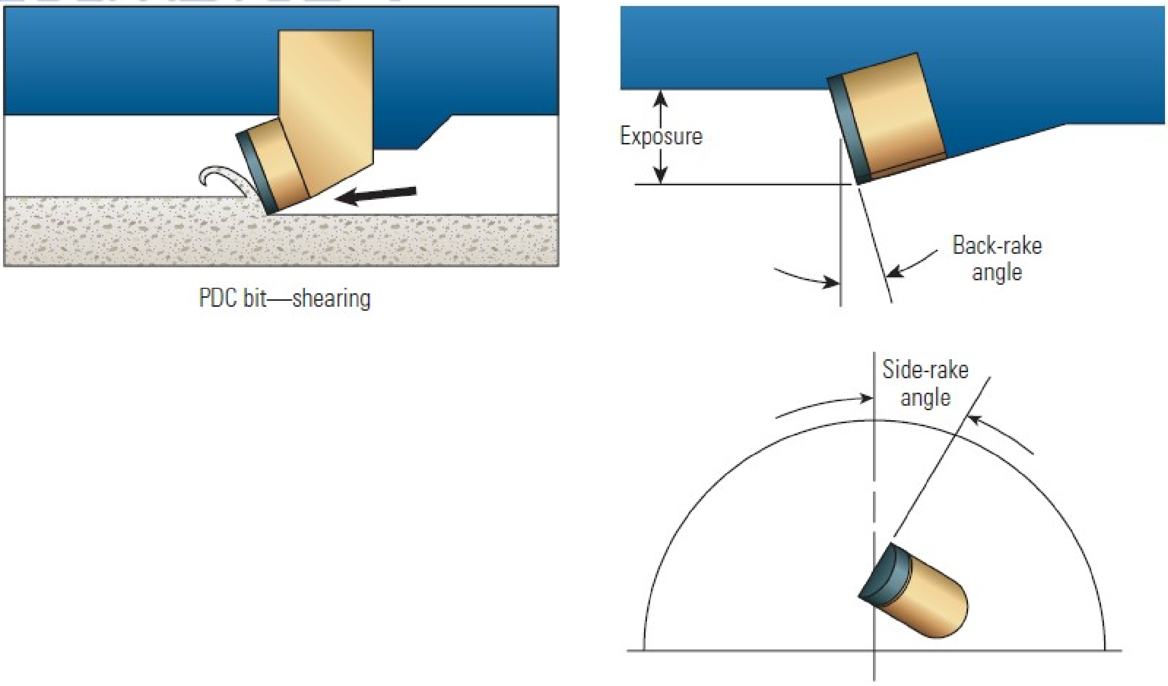


Figure 5-6. Shearing action of PDC bits (top left) enables efficient drilling of homogeneous salt formations, while specific design parameters (top right and bottom right) specify how hard these bits attack the formation (Perez, et al., 2008)

It's important to choose PDC bits correctly. A bit that is not well adapted for the task at hand is likely to create poor-quality boreholes, prematurely wear out, lead to tool failures, and lower ROP. There isn't however any general guideline to apply everywhere, regarding the best design parameters for the PDC to be used in each. Studies contacted in the Gulf of Mexico have shown that the majority of shock and vibration occurrences were recorded in vertical wells, whereas the highest ROPs were achieved in wells without steerability, shock, or vibration issues, as expected. Further, rotary steerable systems made it easier to solve most directional control issues, while, limiting stress and vibration and allowing the BHA to steer the well in the right direction, the operator had to experiment to discover the ideal combination of bit design and BHA components (Perez, et al., 2008).

To overcome drilling inefficiencies of conventional bits, the petroleum industry invested in the research for new more productive hybrid bits, for many years. In 1932 Scott and Bettis designed the first hybrid bit which was a combination of a roller cone bit and a fishtail bit. This bit was developed to decrease the limits of a roller cone bit while drilling plastically behaving rocks, while not harming the capabilities of drilling through harder masses of rocks. Unfortunately, the fishtail wore off too soon while drilling, so that effort did not succeed at a commercial level. In the 80s another effort was made to commercialize hybrid bits, along with the early PDC bits, giving unsatisfied results once again. The lack of durability of the initial PDC cutters and structural flaws in the designs were the main causes of the unsatisfactory performance. Since then, the PDC cutter technology has undergone several significant advancements, and fixed-blade PDC bits have mostly displaced roller-cone bits in all but a few applications.

In 2009 Kymera hybrid bits were introduced, with two main types. The first one is a two-cone and two-bladed bit for small diameter boreholes and the second one is a three cone and three-bladed bit for larger ones (Figure 5-7 left & right, respectively). These bits are similar to PDCs with 4-6 blades, with the difference that their secondary blades are altered with truncated rolling cutters (Håpnes, 2014).

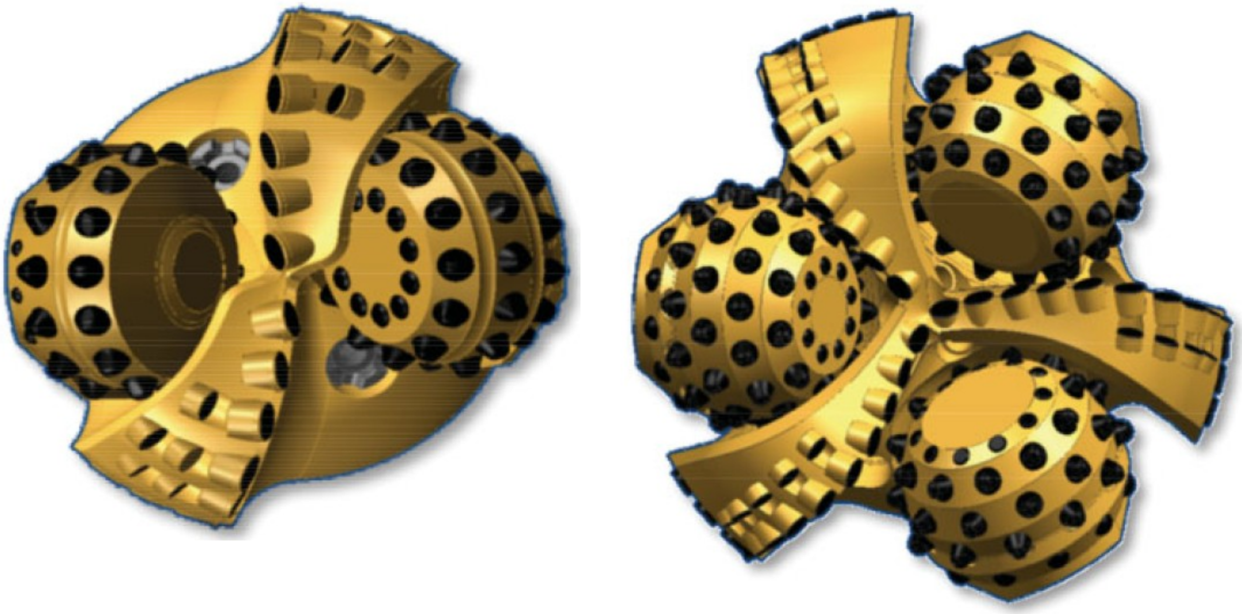
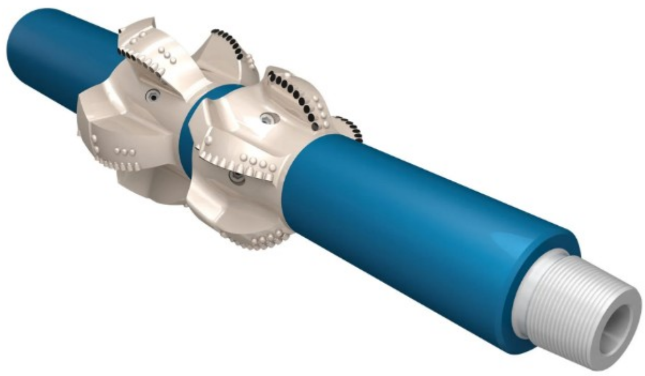


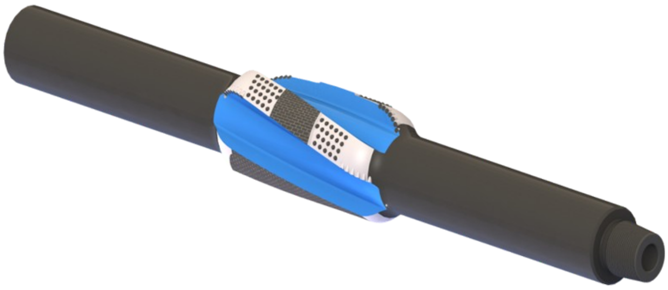
Figure 5-7. Hybrid bits: with two cones and two blades (left) and with three cones and three blades (right) (Pessier & Damschen, 2011)

5.3.5 Under-reamers

All drilling programs aim to produce full gauge boreholes of high-quality, precise formation appraisal, and quick, unproblematic drilling. In salt formations, apart from these aims, there is one more: a reduction in load points on the completion that would otherwise be caused by the salt's non-uniform transverse-loading characteristics. To maximize drilling efficiency with high-quality boreholes where salt formations are involved, operators employ the cost-effective EWD technique. The “enlarge while drilling” (EWD) technique is usually achieved by using concentric or eccentric reamers, and bicentered bits (Figure 5-8).



(a)
(https://www.nov.com/products/concentric-string-reamer)



(b)
(http://modus-oilfield.com/blog/ecreccentricunderreamer/)

(c)
(https://www.nov.com/products/tektonic-eccentric-bi-center-drill-bit)

Figure 5-8. (a) Concentric string reamer, (b) Eccentric under reamer, and (c) Eccentric bicenter bit

There are various benefits to drilling holes larger than the bit diameter since this provides drilling engineers with the ability to use casings with an outside diameter close to the inside diameter of the previous string, leaving a bigger annulus between the casing and the borehole walls. This way swab and surge effects and cementing issues are decreased (Perez, et al., 2008).

In the past decades, concentric reaming devices were associated with mechanical failures during the opening or closing of the reamers' arms. So, these tools have undergone significant advances. Nowadays, ball drop activation of reamers' arms has improved the reliability of these devices. They are especially helpful when it comes to salt creeping hazards, while the running of casings is conducted successfully in lesser time. Under reamers should always be chosen with the selected bit, to avoid the bit to out-drill the reamer causing difficult-to-control shocks, vibrations, or stick and slip effects (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

5.3.6 Rate of Penetration (ROP)

ROP in salt is not that sensitive to the degree of balance between pore pressure (vertical stress) and fracture pressure in comparison to permeable rocks, as it has neither porosity nor pore pressure. Issues might emerge while drilling alterations of salt with permeable rocks by using a PDC bit made especially for salt since salt has a low Unconfined Compressive Strength (UCS) compared to harder rocks such as limestone, anhydrite, and sandstone of low porosity. Additionally, very high penetration rates cause severe bit winding in salt, although both issues are simple to fix. Higher ROPs aid in minimizing problems with salt closure problems, but the existence of dolomites and/or anhydrite sometimes does not allow high ROPs (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

For the enhancement of the ROP in and around salt the following are of crucial importance (Mathur, Seiler, Srinivasan, & Pardo, 2010):

- Improve and diminish connection times. When drilling must be conducted through thick salt bodies, accurate connection management can result in significant time savings, especially in deep water. The average daily expenses for deep-water drilling operations are several hundred thousand dollars, therefore even a small reduction in time will result in significant cost savings over time. Analysis of connection time tactics helps avoid ineffective practices or introduction of new, effective practices will maximize the likelihood of the well reaching its target.
  It should be stated that especially in rubble zones the reduction of invisible lost time (ILT)[11] may achieve major cost savings. For this to happen, crew efficiency must be increased to better control connection times, by conducting, among others, back reaming or circulation between connections.

- Keep well vertical. To reduce drilling torque and bit wear, maintain smooth running of casing and completion, and have a better understanding and control of directional objectives during salt exit, maintaining verticality is a crucial aspect throughout the

[11] **Invisible Lost Time (ILT) related to routine rig drilling operations is the difference between actual operational duration and a best practice target. It is invisible as it does not appear on any conventional morning reports (https://petrowiki.spe.org/Invisible_lost_time).**

salt drilling phase. The fine steering control of rotary closed-loop steerable bottom-hole assemblies makes them suitable for usage.

- Diminish vibrations. Managing vibration is important while drilling through salt. Numerous instances of drill strings experiencing issues because of vibrations, particularly during salt entry and exit, are also documented. Before drilling, detailed BHA modeling can concentrate on setting the drilling parameters (RPM and WOB) correctly. In addition, downhole drilling dynamics should be monitored for torque and WOB downhole, stick and slip effects, and lateral and axial vibration, to increase tool reliability, which, in turn, would reduce the need for costly trips to replace damaged drill string parts. Keeping an eye on the drilling dysfunctions caused by shale inclusions might improve drilling efficiency. Mitigation plans can be also designed and distributed to the rig crew.

5.3.7 Casing design

Casing collapse or deformations are, many times, the reason for wellbore loss when drilling extended sections in salt. In casing design for salt formation, the casing is considered to be empty inside without any pressure acting inside it. At the same time, the hydrostatic pressure gradient on the casing exterior is considered to be equal to the overburden pressure. This tactic might be enough in some cases, but usually, it does not prevent washout events or cement displacement effects that adversely affect casing loading which is hard to forecast and assess. To eliminate these issues, some changes to conventional casing design were recommended to fit the needs of salt drilling (Håpnes, 2014):

- To increase resistance to collapse, select increased pipe thickness (nominal weight) instead of higher steel grade.
- The resistance to non-uniform loading and the radial distortion of the pipe is diminished when considering a uniform load on a single pipe that is subjected to non-uniform loading. Thereof, the probability of tools stuck in the casing and its radial deformation is also reduced.
- If uniform and non-uniform loading are applied at the same time, the pipe resistance to non-uniform loading is increased, which, as a result, will lessen the inner pipe's radial distortion.

According to the literature, extensive "clean" salts do not present casing loading issues. Excessive movements have only been observed in "dirty" salts (with a high proportion of clay impurities) or salt intervals that are interspersed with shale, at rates of up to 1 in/h (2.54 cm/h). Another factor for non-uniform casing loading is also the topography of the salt formation. Fewer problems appear where salt is relatively flat, compared with increased stratigraphic dips.

In the offshore region, where salt is located deep below the sea bottom, it is advantageous from the standpoint of drilling to set the casing deep enough into the salt so that the increased fracture pressure can be used to place the next casing string as deeply as feasible (Figure 5-9 A). However, attention is needed to cope with issues regarding salt loading and mobility. The first concern is whether the salt will stay sufficiently in gauge to allow drilling to proceed without the danger of tight hole issues. The second concern is related to the zone of low fracture gradient that typically exists after exiting the salt. Due to the fracture gradient's potential inadequacy to support a column of even foamed cement, this "weak" zone may make it impossible to cement the annulus between the casing and salt. Therefore, it is likely that the salt/casing annulus will have to remain uncemented with a deep-set casing through the salt. This poses issues with salt movement over a longer period and loading to the well casing.

The drawback of using a conservative casing design is significant. The casing will need to be set somewhat close to where the salt exits if a cemented annulus is needed through the salt (Figure 5-9 B). The fracture gradient in this location may be comparable to or even lower than the fracture gradient seen at a deeper depth. As a result, it may be necessary to set a casing string or a liner tieback without necessarily moving the well much closer to its target formations at depth. To advance the well to the same depth as that achieved in the earlier, more aggressive design, it will be necessary to set a second liner and reduce the bit size in this case (Willson, Fossum, & Fredrich, 2003).

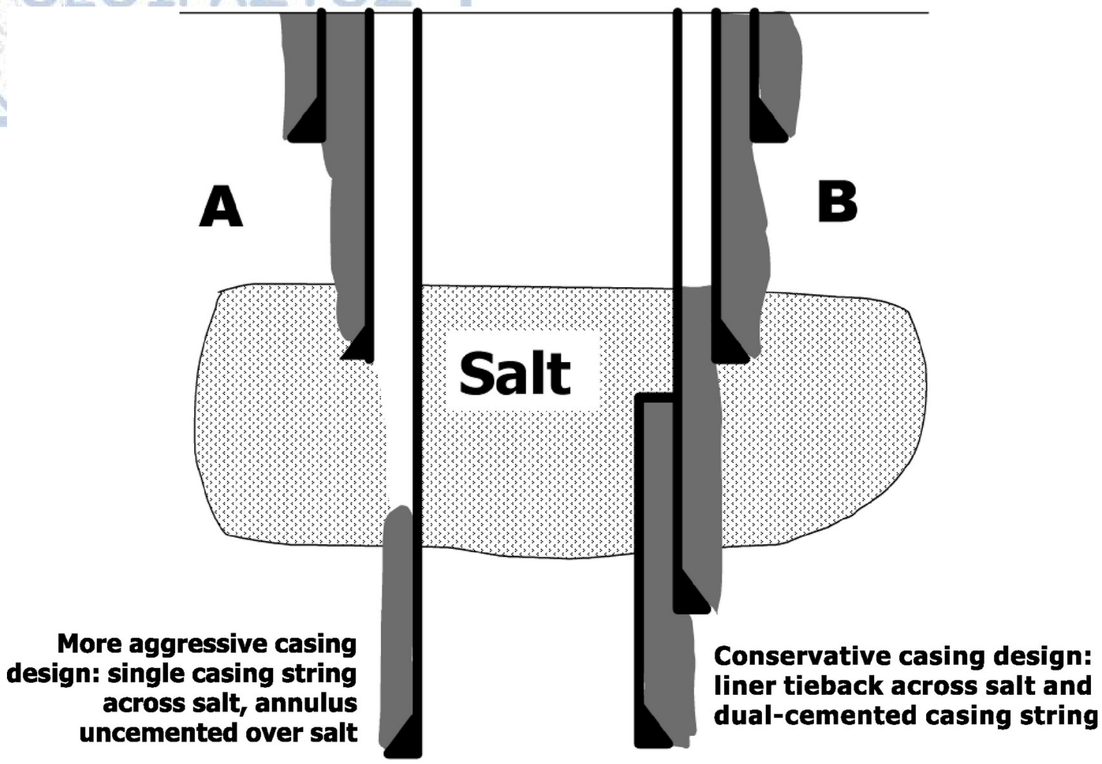


Figure 5-9. Schematic of the different casing and cementing designs in salt (Willson, Fossum, & Fredrich, 2003)

If the well design along with the casing design considers the appropriate amount and timing of salt loading, there are important gains. It is possible to omit liner tiebacks and challenging cementing tasks, within either borehole/casing annulus or casing/casing annulus. Because a casing string or liner need not be set while leaving the salt, casing setting depths can be defined more aggressively. In deepwater wells, the resultant simpler casing design and the removal of potentially problematic activities can result in millions of dollars in cost savings.

5.3.8 Cementing

After the drilling and casing of a salt formation cementing processes should follow. Salt creeping can affect casings in a major degree that might lead to casing failure or collapse, (Figure 5-10 left). Thus, apart from zonal isolation and structural support, types of cement that are meant to be placed in a salt zone must be modified so the inescapable loading caused by creeping is uniform. This is achieved by enhancing the flexural and tensile strength of the cement, to cope with all loading conditions that will exist throughout the entire life of the well.

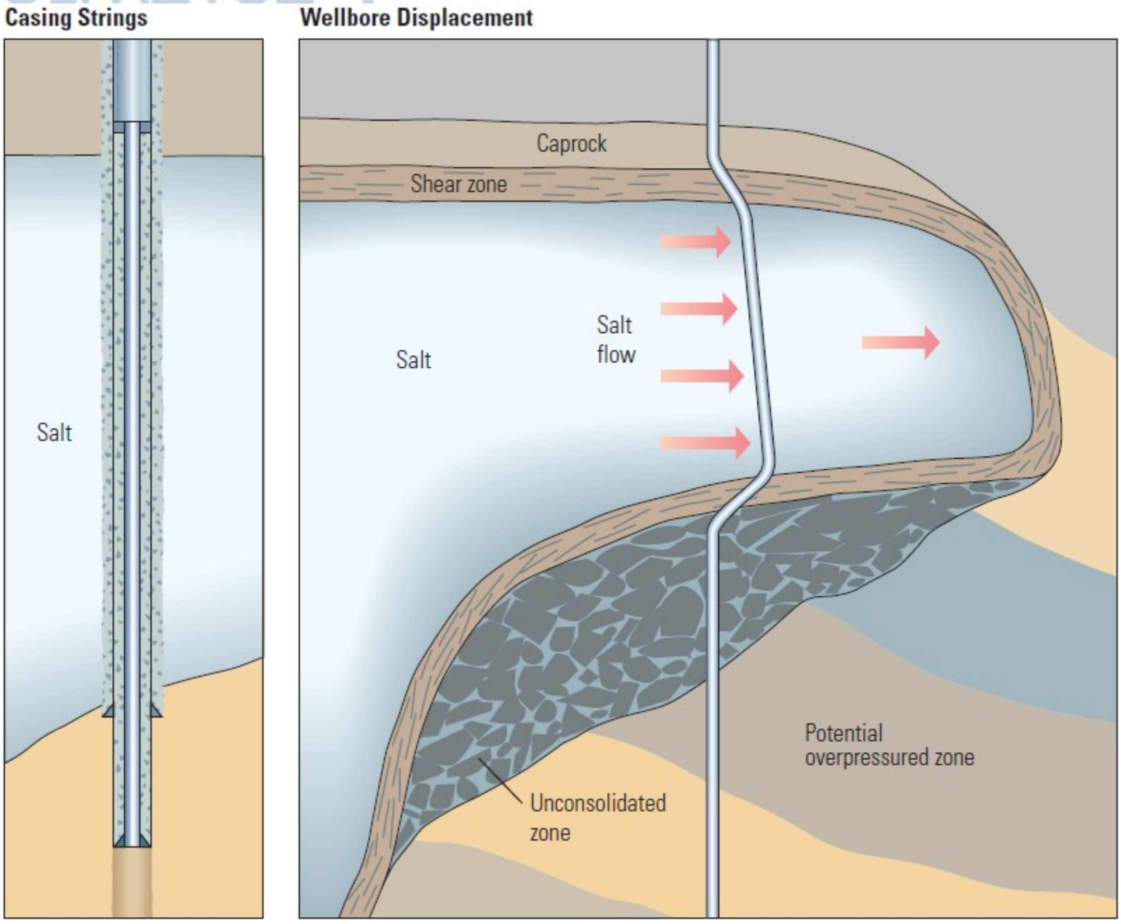


Figure 5-105. Cementing difficulties across mobile salt (Perez, et al., 2008)

Cement specialists in the past used salt-saturated slurries of cement thinking that this would endure chemical attacks from the formation and gas migration effects during setting, the cement would connect better with the borehole walls, and lessen the possibility of dissolving the salt. But when it comes to concentrations above 18% by weight of water, salts increase the thickening time and lessen the compressive strength of the cement, and, thus, boost circulation loss and free water development[12].

That led specialists to use cement based on the characteristics of each salt formation (salt content). In general, low-salinity slurries, containing 10% NaCl or less by weight of water, have been reported to develop early strength and good rheology where salt creeping exists. It should be noted that cement bond logs must be performed to interpret any inefficient bonding due to salt creeping.

[12] **Even if the cement has reached its maximal displacement, salt will dewater it through osmotic suction, creating an annular zone of free water. In pure salt, this is not a significant problem because continual closure would eventually expel the brine, resulting in uniform loading, but in sedimentary rocks (matrix-supported) with salt in the pores, a gap between cement and the rock can be created (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).**

Another important parameter, that should be taken into account in the design of the proper cement slurry, is temperature. High temperatures greatly speed up the rate at which salt dissolves, thus moderating the development of the delayed compressive strength in cement slurries rich in salt. Specifically, 10-18% salt-saturated slurries are recommended for temperatures below 200°F (93°C), while 18-36% salt-saturated slurries are recommended for temperatures above 200°F.

Cement sheaths placed across salt formations may succeed or fail for a variety of reasons, but cement slurry design is only one of them. A factor that significantly affects slurry quality is the salt formation itself. For instance, it has been demonstrated that a 10% contamination of a freshwater cement system can change thickening time by 30%, increase slurry viscosity by 100%, and nearly double fluid loss rates (Perez, et al., 2008).

Another issue that must be considered is that cement slurries with high salt concentration can over-retard cement, which makes mixing them challenging. Dispersants and fluid loss control additives may also be necessary. When cementing casing through extensive salt sections, salt-free cement, and semi-saturated cement have been utilized to prevent over-retarding of cement, but there is a general concern that these cement will lose strength with time. It should be stated that the ion exchange of calcium and magnesium, which exist in brines, could also lead to cement failure.

Some researchers suggest adding a small amount of KCl in the cement used in salt drilling procedures to achieve some balance in salinity between the salt mass and a low salt-saturated cement. That practice has proved to be successful if free water and loss of fluids are in control. Moreover, in the late 1980s, specialized additives were created to minimize the drawbacks of utilizing cement that was heavily salted (Håpnes, 2014).

Using denser cement can occasionally be a viable answer to possible salt concerns. The filler material is a well-graded quartz with a wide variety of grain sizes, with D50 ranging from 20 m (silt) to 500 m. (coarse-grained sand). To maintain pumpability, Type-G cement content is decreased, and a superplasticizer agent is added. This enables the application of cement that is far stronger and less likely to shrink when set than ordinary cement, leading to a stronger final construction (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

5.4 Well control

5.4.1 Mud system

Mud selection is subject to special requirements while entering, drilling through, and exiting salt, much as drilling in salt necessitates specific BHAs. Drilling fluids must be properly selected to balance the sometimes conflicting interests of ROP, borehole quality, wellbore stability, and affordability because of salt washout or leaching, creep, suture zones, and other inclusions within the salt, as well as the unknowns connected with the rubble zone (Figure 5-11).

For example, when under-saturated brines or even seawater is used as drilling fluid to drill salt formation, ROP rises considerably, even though they can cause salt leaching and, thus, substantial hole expansion. Further, when drilling riserless into the top of the salt employing seawater, this results in significant cost savings while also removing the need to use up valuable rig space to store weighted brines (Perez, et al., 2008).

To choose the proper mud system one must evaluate the fundamental properties of each drilling fluid while correlating those with the specific needs of each particular field to be drilled.

5.4.1.1 Fundamental drilling fluid properties

Three are the fundamental drilling fluid properties to be discussed in this chapter:

- Density
- Salinity
- Rheology

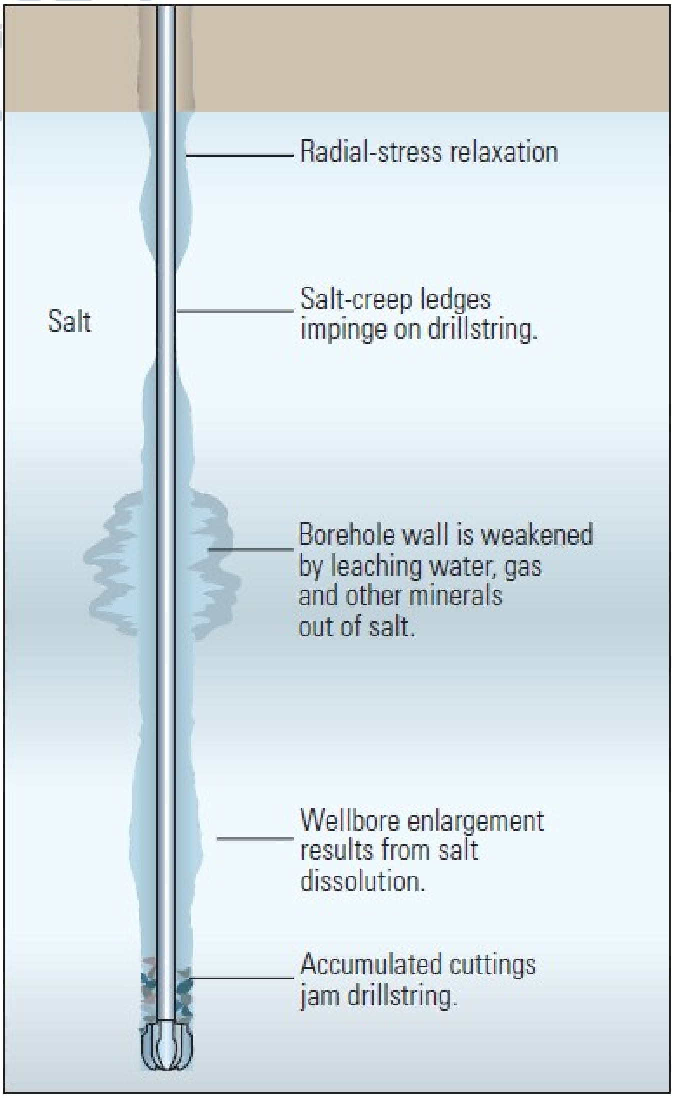


Figure 5-11. Borehole problems related to poor selection of appropriate drilling fluids when drilling through salt (Perez, et al., 2008)

Density

Pure salts are basically impermeable. Salt granules, under high temperatures and stresses, compact and expel brine as long up to the point where remaining porosity reaches a minimum between 0.3 to 1.5%, filled with brine. According to (Dusseault, Maury, Sanfilippo, & Santarelli, 2004), mud pressure operates fully and straightforwardly on salt, under the previously stated conditions, thus filter-cake cannot be formed.

The elimination of salt creeping rates is the most important role of the mud weight's selection. According to (Aburto & D'Ambrosio, 2009), increased mud weights are more efficient in dealing with salt creeping than using under-reamers, thus reducing the chance of stuck pipe or tight hole events. Also (Leavitt, 2009) refers that a higher mud weight is advantageous since it can reduce torsional vibration and stick and slip effects. For this to happen, he suggests that the proper hydrostatic pressure should be up to 90-95% of the pressure of the overburden, while he also advises a schedule of increasing mud weight (Amer, Dearing, & Jones, 2016).

Salinity

The drilling fluids should always be almost or fully saturated in a type of salt similar to the salt to be drilled, to reduce as possible its dissolution, and thus the washout events and keep the borehole in gauge. Unfortunately, there are some complications regarding the conservation of the proper salinity.

Very low salinity seawater is frequently utilized in salt drilling if the goal is to drill more quickly or mitigate a stuck pipe incident. A salt-saturated drilling mud with a specific salt, might not be saturated with salts that are occurring in the salt formation to be drilled, while it is also common for a saturated fluid on the surface to evolve into under-saturated at higher depths and thus higher temperatures. Regarding formations adjacent to salt, since they usually contain in their pores fluids of higher salinity, they therefore usually require the use of increased salinity oil muds (Dearing, 2007).

In any case, to comprehend salinity, it is important to understand the leaching and dissolution processes of salts. One crucial factor for these processes is the flow regime (Amer, Dearing, & Jones, 2016).

Rheology

In salt drilling, well intervals are mostly vertical and the boreholes are cleared successfully due to the considerable flow rates that successfully transfer cuttings to the surface at considerable annular velocities (Leavitt, 2009). Besides proper annular velocity, drilling fluids should also have proper viscosity. As required by (API RP 65, 2012), viscosity must be kept low enough to allow for effective cutting removal while not creating too much friction pressure that would increase the equivalent circulating density (ECD) to the point to fracture the formation. When using kill fluids for riserless drilling operations, it is advised to maintain adequate rheological characteristics to suspend the weight material and excess salt. The fact that the rate of salt dissolving slows down as viscosity rises is an indirect advantage of viscosity. It is important to know that, while viscosity increases, salt dissolution decreases (Amer, Dearing, & Jones, 2016).

5.4.1.2 Main drilling fluid selection criteria

In the past, the choice of the proper drilling fluid for salt formations was made to drill a gauge hole. Recently, other performance parameters have been added including enhancing the rate of penetration (ROP) and reducing salt creeping more recently. In general, the selection of drilling fluids is typically influenced by factors like cost, performance, and environmental compliance (Amer, Dearing, & Jones, 2016). The latter is the reason that oil-based muds are not examined here.

Cost

Mud cost should be approached holistically and evaluated against other costs, such as the cost of each interval, as well as the cost of the entire well. A mud that reduces drilling time due to its effectiveness undoubtedly justifies higher costs.

Performance

When it comes to performance, some opposing interests exist. The major performance criteria are ROP, wellbore stability, hole cleaning, and washout minimization. Israel et al. (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008) ascribed some of the shock and vibration damage to improper drilling fluid design, layered salt deposits, and salt creep, but there may be other factors that affect performance (and eventually cost).

Environmental Compliance

Each government has different laws and regulations when it comes to the limits of the drilling fluids, so environmental compliance depends on the field’s location. The legislative and regulative regime administers the restrictions and the proper selection of drilling fluids to be used and the type of drilling fluid. It also administers whether the returns can be disposed to the seafloor or are considered hazardous wastes and must be disposed of accordingly. The rules and the disposal strategies that apply in every case may affect choices like the use of certain solvents that might contain tars in the drilling fluid.

5.4.1.3 Evaluation of different drilling fluid types

For mud selection, the chemical composition of the water phase should be examined, while complying with the general rule which states that the water phase should be saturated with as soluble salts as possible.

Two are the main types of drilling fluids, that will be discussed in this chapter:

- High-Performance Water-Base Mud (HPWBM), and
- Synthetic-Base Mud

Water-Base Mud (WBM)

There are a variety of options when it comes to the chemical makeup of the water phase, but in every case, this is determined by mineralogy. As a general guideline, the water phase should be saturated with the salt or salts that are most likely to be soluble (except if they are only present in thin layers). So, while KCl-$MgCl_2$ is typically used in the North Sea, NaCl is typically utilized in the Gulf of Mexico. Failure to implement this technique could result in major issues with corruption of the drilling fluid, flocculation, and trouble in drilling deeper. The mud system needs to be replaced to continue drilling, and during the wait—which frequently includes issues with density maintenance—the hole closure is so large that it necessitates reaming the entire section or taking a detour.

As early as the 1970s, salt-saturated WBM, with added attapulgite to regulate viscosity, had already shown its limitations. As already mentioned, a WBM that is salt-saturated at the surface temperature would probably turn out to be under-saturated downhole, due to the rise of temperature. This results in washouts that frequently go beyond the capabilities of mechanical calipers. Subsequently, cementing operations are eventually exceedingly difficult and the quality of the cement sheath will be poor. In turn, the uneven cement sheath causes irregular casing loading, which results in unexpected casing collapse.

To prevent hole enlargement issues, operators in the North Sea have used a different WBM method in which the mud is heated on the surface using a heat exchanger to get it to the same temperature as the downhole conditions. Less downhole dissolution happens when the hot mud is saturated with salt, and this technique has been quite effective (Dusseault, Maury, Sanfilippo, & Santarelli, 2004).

As operators move to deeper waters, the temperature at the bottom of the sea declines, providing the lowest temperature point in the well, which demands superior hydrate inhibition at the sea floor. For this reason, the applications of this specific type of fluid are decreasing over time. Regarding cost, while the initial cost of the WBM, at the beginning of drilling operations, is considerable, when the cost is spread throughout a drilling campaign, WBM tends to become more cost-effective.

Regarding performance, when WBM is well designed, its performance is similar to synthetic-base mud, and its compressibility and rheology are more easily controlled in different pressures and temperatures, as in deep-water applications. Regarding environmental compliance, WBM is not that recyclable and might need biocides depending on the formulation of the fluid (Amer, Dearing, & Jones, 2016).

Synthetic-Base Mud

Using conventional salt-saturated mud to cope with the usual difficulties in salt drilling (drilling through sutures and inclusions of higher or lower pore pressure than the surrounding salt is more prone to kicks or lost circulation and salt creeping) came with low penetration rates, poor hole integrity, lost returns, bit balling and packoff problems. To cope with these shortcomings, drilling engineers started to use synthetic-base mud (SBM) or synthetic oil-base mud (SOBM). Due to its significantly higher cost than WMB, operators have normally stayed away from using SOBMs for drilling in locations with lost circulation potential. However, even though SOMB can achieve high ROP and adequate wellbore stability, its viscosity increases with temperature and pressure (as the well goes deeper). This results in higher equivalent circulating densities which, in turn, may cause circulation losses, especially in deep water where the drilling window could be extremely small.

For example, in 2000, after having drilled an 8,000-ft [2,438-m] salt section in its first well with salt-saturated mud, one Gulf of Mexico operator switched to a SOBM system for the next well. The second well, which penetrated the same zones, required 78 fewer drilling days than the first well for a cost savings of about US $12 million.

However, higher ROPs and better hole stability, which can greatly cut down costs for casing and cementing operations, have made SOBM the drilling fluid of choice for many operators drilling in and below the salt. Furthermore, these pros along with its contamination tolerance and hydrate inhibition capacity can save many days making it more appealing in the ultra-deepwater sector. For instance, in 2000, an operator in the GoM drilled a salt section of 8,000ft (2,438m) in its first a first well using salt-saturated WBM and for its second well switched to a SOBM system. The second well cost around $12 million less to drill than the first well, and went through the same zones, while it needed 78 fewer drilling days.

Since the industry has created SOBM of flat rheology to combat its con to exhibit excessive viscosity at high temperatures and pressures, SOBM is becoming more and more popular. As temperature and pressures change, the new system is made to retain constant rheological properties (Figure 5-12). The flat rheology maintains cuttings-carrying capacity and barite suspension qualities while permitting a higher viscosity without increasing equivalent circulating density (Perez, et al., 2008).

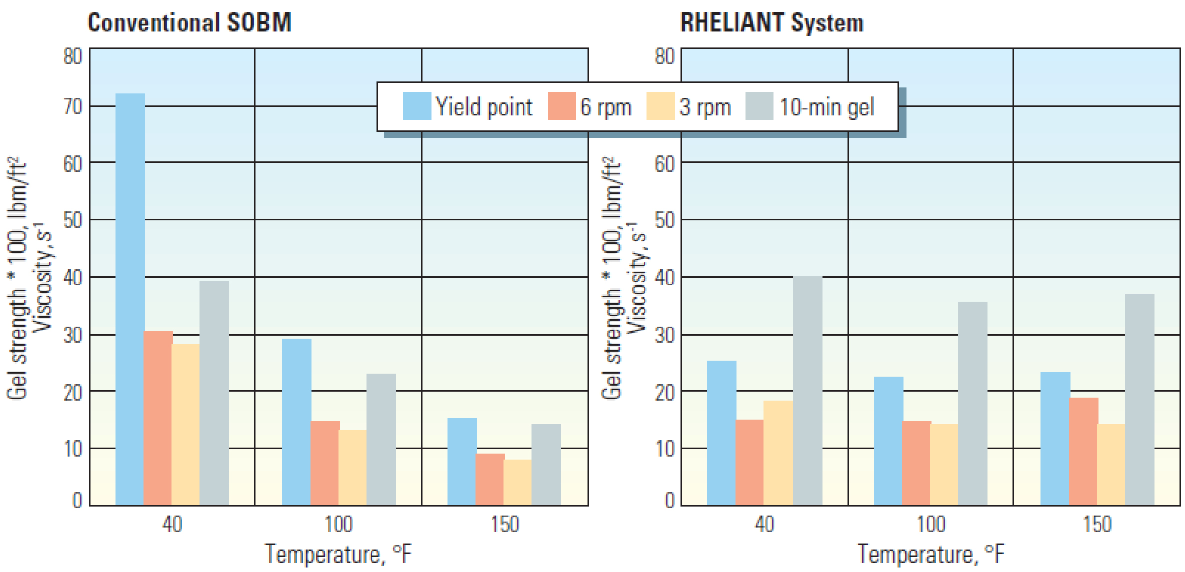


Figure 5-12. Rheological characteristics of conventional synthetic oil-base mud (SOBM) vs. flat-rheology SOBM. SOBM with flat rheology, on the right, has steady constant gel and shear strength for a considerable range of stresses and temperatures maintaining high ROP, low ECD, and its viscosity rate, while efficiently cleaning the borehole (Perez, et al., 2008)

Regarding environmental compliance, the regulative and legislative frameworks for SBM and SOBM disposal and/or discharge vary depending on geographic location (Amer, Dearing, & Jones, 2016).

5.5 Other drilling aspects

5.5.1 Real-time monitoring

Real-time monitoring has become a common practice in salt drilling to efficiently anticipate and manage drilling difficulties. It helps increase the lines of communication so that the teams in the office and on the field can work together more effectively. Data acquired must rapidly produce the information that can be displayed with the least amount of latency in the appropriate context and in a manner that is useful for drilling engineers to act efficiently and on time. Shocks and vibrations, torque and drag, hole cleaning, pore pressure estimation, etc. can all be monitored vs. time or depth (Figure 5-13). Real-time monitoring can decrease NPT by facilitating the optimization of the drilling parameters and enabling the early diagnosis of hazardous events (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

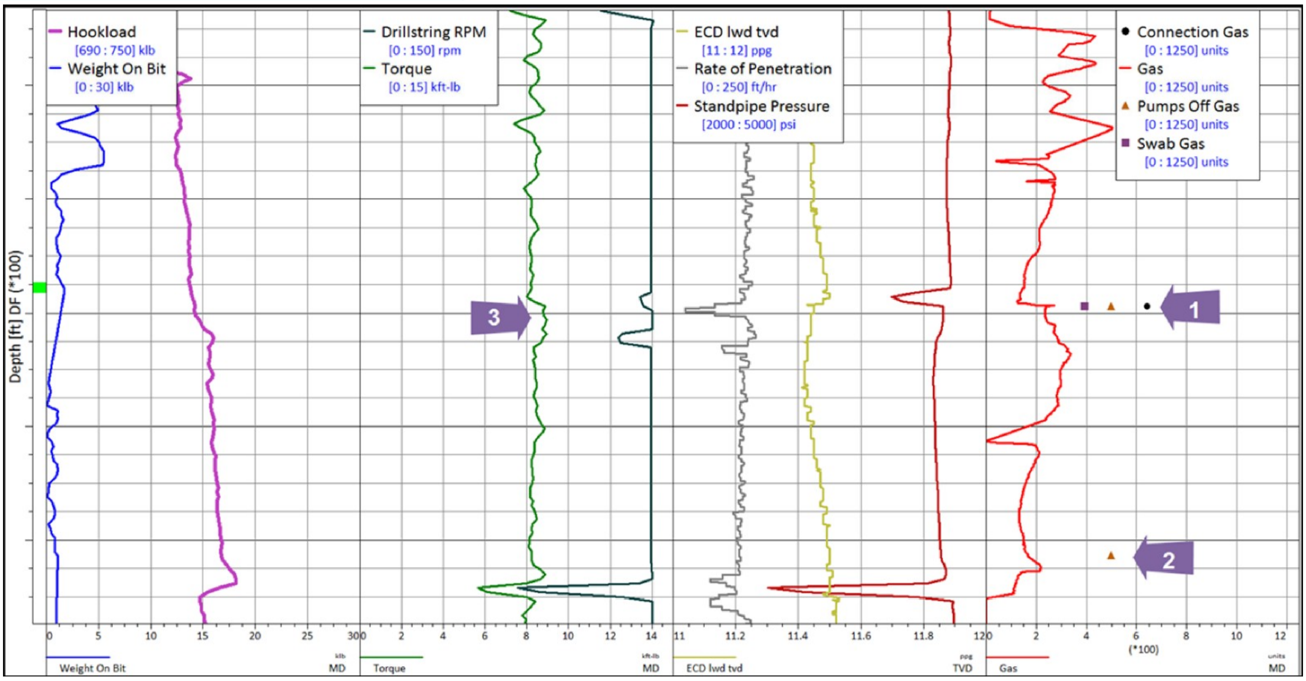


Figure 5-13. Drilling parameters are shown on a depth-based plot for a 270-foot section. Point 1:The bit was off bottom when three separate gas peak events—a swab gas, pumps off gas, and connection gas—were produced from this depth; however, they are not accurately depicted on this plot. Point 2: While the bit was off bottom, a pump-off gas peak was formed. Point 3: A wellbore instability incident that occurred while the bit was off bottom and caused a high torque (Moore, et al., 2016)

5.5.2 Measurements While Drilling (MWD)

Salt drilling requires the same measurements of drilling dynamics as those used in other challenging drilling situations (Figure 5-14), such as stick-slip data, downhole WOB and torque, and vibrations (lateral, axial, and torsional). Annular pressure is also necessary for ECD measurements.

A Telemetry tool is a new development in data transmission technology, providing the ability to program the tool to transmit various data arrangements. This implies that stick-slip and vibration data points can be used to optimize the tool bandwidth while drilling salt. After exiting salt, the tool can be instructed to switch to another preprogrammed data frame, that can leverage the sonic and ECD data points for real-time pore pressure modeling (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

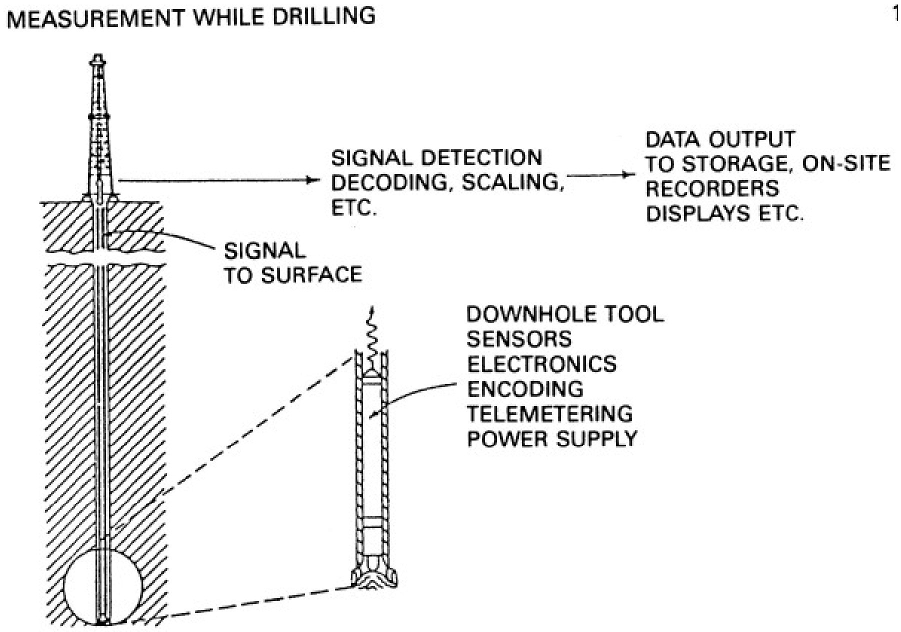


Fig. 8.1. Overview of measurement while drilling system.

Figure 5-14. Sketch of a MWD system (Inglis, 1987)

5.5.3 Logging While Drilling (LWD)

Even though very few petrophysical measurements are necessary for salt, several specialized measurements can be used to enhance drilling.

Gamma-ray logs provide useful measurements within 10 feet of the bit that can validate or link changes in drilling parameters (ROP, WOB, torque) with changes in lithology related to drilling an inclusion or entering the top of the salt.

Sonic logs are used to improve real-time modeling of pore pressure while drilling to enhance model accuracy across inclusions and in the layers beneath the salt. Sonic logs can also be used after drilling for the geomechanical modeling of salt to identify the stress regimes in salt, helping in well planning of wells to be drilled in the future. Drilling noise is harmful to sonic data, so a proper BHA design should be applied, with BHA vibrational analysis, to eliminate this impact.

Last but not least, operating seismic logs while drilling can provide renewed information about the base of salt depth or targets below salt located in real-time. This information might lead to trajectory and inclination alterations in order not to miss the target (Israel, D'Ambrosio, Leavitt, Shaughnessey, & Sanclemente, 2008).

5.5.4 Critical personnel - Communication

While the advancements in drilling equipment are of major importance to efficiently drill any well, should not be ignored the preparation of employees to handle these advancements and make the right decisions when needed. To fully grasp the issues that may arise with drilling salt, drilling engineers and other wellsite staff must be taught in using any techniques that may be required.

Communication improvement on the rig can deeply and positively affect salt drilling, especially when dirty salts are encountered. When onsite analysts set up monitoring stations in the company man's office, in the driller's shack, in the geologist's room, and on the logging unit, synchronized data are displayed to each group that has a say on the field in real-time. This way a considerable amount of hazardous events can be prevented, minimizing related risks and delays (Chatar, Mohan, & Imler, 2010).

5.5.5 Shore support for offshore wells

Using shore support with real-time centers and monitoring can increase drilling efficiency, bringing heightened awareness across the total personnel of each company that performs offshore drilling, especially when salts are predicted to be encountered along with the risks they will present.

CONCLUSIONS

Continental or marine evaporites, can be divided into primary, secondary, or tertiary, according to the changes that have undergone in their primary structure and composition. They can either source rocks or, more commonly, seals and traps for hydrocarbons. Formations below evaporites often withhold considerable volumes of oil and natural gas. Although major innovations in exploration and drilling technology have permitted these kinds of targets to be reached, the economics of such projects remains a severe task. The limited ability to accurately image the base of salts and the formations below is the first thing to be dealt with to meet the exploitation targets. The seismic industry manufactures pioneering equipment and develops new processes to comply with the demand to throw light in even greater depths. Be that as it may, drillers have to be able to drill through thick salt sections and the formations beneath them, putting behind the fear that they experience in the past, that salts are so troublesome that it is better to avoid them.

The physical and mechanical properties of evaporites lead the salt behavior that is quite hazardous when drilling through this kind of formation. The most common hazards associated with the existence of salts arise from tectonically unstable zones, thrust faulting stress regimes, rubble zones or zones with pressure depression, inverted bedding, sutures, and inclusions. All these hazards cause several drilling problems associated with drilling above, through, and below the salt, such as loss of circulation, wellbore instability, salt creeping causing tight holes and stuck pipes, washouts, hole collapse, and irregular and uncertain pore pressures.

Careful planning is necessary for salt drilling, which includes examining offset well records and exploration data. A simplified well design and the avoidance of potentially problematic activities can result in significant cost savings for each well. A significant drilling technical difficulty is ensuring the integrity of subsalt wells throughout the field's lifespan. The expenses of remediation and lost production from well failures might be inconceivable. On the other side, the overly cautious well design comes at a significant cost, which encourages thorough analysis of casing loads for relevant scenarios.

One common practice to deal with evaporites is drilling through them vertically. Improvements in drilling rigs led to a drilling procedure with more efficient torques and rotary speeds. The use of RSSs increases the ROP and produces smoother wellbores. Polycrystalline bits are most commonly preferred now for salt drilling. New hybrid drill bits, even expensive, is the state of art for reducing shock and vibration levels while drilling, improving borehole quality, increasing ROP, and improving bit and BHA life. Enhanced ROP in salt, reduces ILT along with major costs, while also maintaining verticality and reducing vibrations.

Moreover, side-cutting reamers are also used to retain the borehole in gauge. These methods prevent under gauge hole events, helping this way the drillers to perform directional drilling if necessary. Recently developed ball drop activating reamer arms are helpful when it comes to salt creeping while setting casings can be conducted successfully in lesser time. Under reamers should always be to match the selected bit, to avoid the under reamer drilling the bit out, and cause, this way, excessive socks, vibrations, or stick-slip events.

Regarding the mud system selection, fundamental properties such as mud's density, salinity, and rheology should be carefully evaluated along with the cost and the performance of the drilling fluid, without overlooking the environmental compliance and the specific features of each field. Synthetic-based fluids are the most preferable since they achieve high ROPs, contamination tolerance, and hydrate inhibition capacities. Last but not least, fluid performance differs between salt layers as salt mineralogy varies both within and between sedimentary basins.

When it comes to cementing the annulus, experience has shown that, if hole quality can be guaranteed, it is not necessarily essential to cement the casing/borehole annulus via the salt since the ensuing uniform stress is inadequate to significantly distort the casing. Long-term drilling operations are not at risk, there is no impact on the inner casing string, and there are significant financial savings as a result. A cemented annulus is required, nevertheless, if the hole quality is inadequate, as the cement effectively converts the possibly uneven loading condition into an even distribution of load. In this case, the cement slurry should be carefully selected to form a sheath that is as uniform as possible, that won't aloud irregular loading to deform the casing.

Other important aspects of drilling in salt to be considered during well design and construction are real-time monitoring, MWD, LWD, and proper training of the drilling personnel. Real-time monitoring of the drilling parameters helps increase BHA life and optimize drilling performance, while it can be done either at the rig site or from remote centers. Finally, communication between the drilling teams is of crucial importance to timely detect and mitigate every problem to appear when drilling through salt.

If there must be some kind of overall conclusion, it can be said that there is no place for ill-informed decisions when it comes to salt drilling. This fact has forced both service providers and operators to implement new strategies and new technologies to guarantee that the correct information is always accessible, to shorten the response time when difficulties arise, and to reach targets both safely and efficiently.

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