AADE-16-FTCE-16

Drilling Challenges Related to Dirty Salt

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Abstract

There are growing drilling challenges in the subsalt deepwater frontier area of the Gulf of Mexico. Most of the troublesome wells were drilled in salt with embedded rafted sediments, i.e. dirty salt.

Salt's low density, negligible permeability, and ductile nature create a unique pore -fracture profile. A clean salt mass is usually driven down-dip by buoyancy. On the other hand, in dirty salt, the sediment's influx thrusts salt to creep down-dip. This leads to plowing the salt - sediment interface and creates subsalt gouges. Moreover, thrust force causes principal (sigma1) and minimum (sigma3) stresses to exchange position. The rafted sediment embedded within the salt creates unanticipated excess pressure.

The drilling tolerance window (FP-PP), should stay unchanged when penetrating clean salt. In dirty salt an unexpected increase of MW and possible additional casing seats are needed. Penetrating the fragile gouge zone at the salt's base with overbalanced mud leads to the complete failure of mud return, side track attempts and sometimes abandonment.

In the cases of Jack vs. St. Malo and Atlantis vs. Hadrian wells, drilling challenges due to penetrating the dirty salt are exhibited. Jack and Atlantis encountered several hurdles whereas, St. Malo and Hadrian reached TD as planned with minimum challenges.

Tracking salt's displacement and emplacement history, assigning the correct stress vectors and recognizing the rafted blocks on seismic semblances are important essentials that can help predict the drilling tolerance window (DTW) and better manage drilling in this frontier Salt Toe area.

Introduction

In the Gulf of Mexico Tertiary-Quaternary, geopressured sediments are mainly caused by compaction disequilibrium phenomenon. Sediment influx and compaction processes due overburden and salt imposition control this process. The presence of salt masses in a sedimentary column contributes to substantial changes in the pore pressure gradients in the host sediments above and below the salt layer. Salt's low density is responsible for retarding the overburden gradient below the salt and, conversely, enhancing it above the salt. The negligible permeability of salt creates a perfect seal and the absence of fluid within the salt body leads to negligible pore pressure. Moreover, salt's ductile nature generates a variety of structural styles that impact the stress orientation and magnitude. Therefore, the complex nature of the subsurface geopressure profile in salt basins represents drilling challenges when testing a subsalt prospect.

In the subsalt plays, especially in the frontier salt toe area with a thick seawater column (> 5,000 ft), some of the main engineering challenges are:

- Thick water column above the mud line (sea floor) leads to a substantial reduction in the vertical stress. Dual riser drilling was adopted for that.
- Drilling through a thick salt body requires special mud chemistry and components
- Creeping of shallow salt down-dip can creates slumps along the Sigsbee escarpment, which results in instability and damage to the bore hole and casing during and post operation.

While the previously mentioned engineering challenges can be overcome with applying advanced drilling technology, the inherited geological related challenges are far from resolved. They most likely related to:

- The embedded rafted blocks of sediments within the salt body, which have pushed down dip contemporaneous with the salt movement.
- The gouge zone at the salt base – sediment interface, have created by the salt plowing the older sediments during the salt movement toward the deep basin.
- The lateral salt thrust leads to create a lateral tectonic stress greater than the vertical overburden stress. This causes uncertainty in pre-drilling pore – fracture pressure predictions.

While there is a great deal known about salt body delineation from geological and geophysical data, this article addresses the Gulf of Mexico Sigsbee salt toe related drilling challenges from a geopressure standpoint.

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Definitions and concepts

Geological setting

The Sigsbee escarpment in the deep water represents the front belt (toe) of the allochthonous Jurassic Louann salt (Figure 1). It is a structural nappe that thrusts the underlying sediments (Rowan et. al., 1999)[1] and forms several structural traps (Chowdhury and Lopez-Mora 2004)[2]. Over a long time (Jurassic-Recent), the salt moved quite a distance from central Texas to the Gulf of Mexico Abyss. Salt buoyancy and influx of younger sediments are the driving mechanism of this long journey. This process intermittently took place due to the immense sediment influx especially during the Pleistocene-Holocene Mississippi delta expansion.

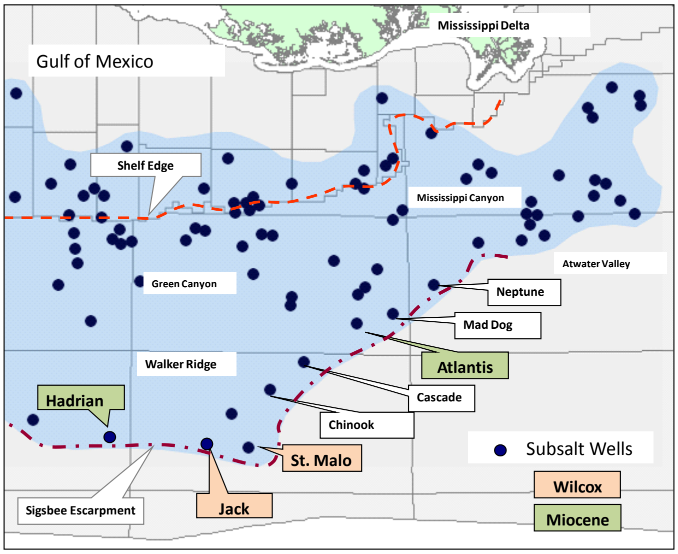

Figure 1: *Location map shows the Sigsbee escarpment and the associated salt Toe trend. Green and pink are wells targeted Miocene and Wilcox respectively.*

A sediment drape usually overlays the salt nappe in the presence of nearby deposit feeders. On the other hand, in sediment starved skirt areas, salt can be seen creeping on the sea floor. The stress generated from the lateral movement of the salt creates a variety of compressional structural closures associated with thrust fault systems in the underlying Wilcox and Miocene sediments (Figures 1 and 2). These structural closures are the exploration targets of the new emerging deep-water exploration play.

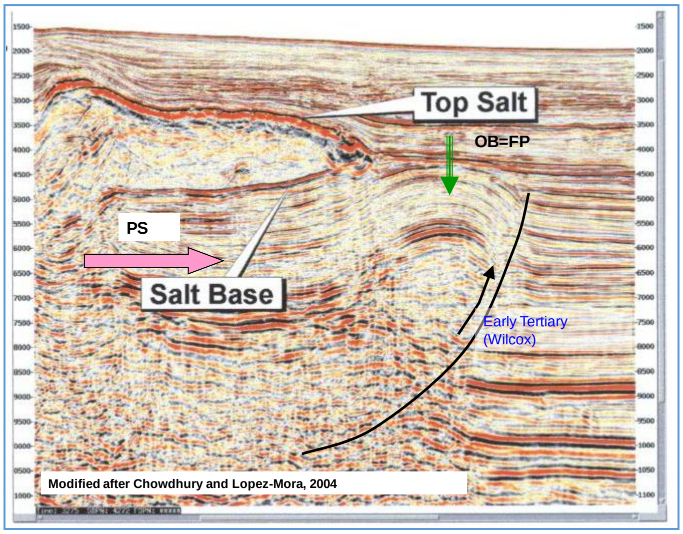

Figure 2: *Seismic line at the Sigsbee salt toe shows the salt thrust represents the PS. Sediments buckled up because PS is greater than OB. OB represents the minimum stress (FP).*

Embedded rafted sediment blocks occasionally carried within the salt mass and moved down dip. This can generate excess pressure cells within the salt. Moreover, the salt plows the underlying sediment and creates a sheared zone of rubble (gouge) at the base of the salt. This causes excessive loss of circulation at the base of salt.

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Geopressure Modeling

Stress fields, in particular the principal maximum (σ 1 / PS) and principal minimum (σ 3 / Shmin / FP) stresses, determine the pore and fracture pressure envelopes in the subsurface sedimentary column. Principal stress dictates the progress of the pore pressure (PP), meanwhile fracture pressure (FP) represents the pressure breaching limit. The intrusion of salt within the sedimentary column impacts the magnitude of the maximum stress above and below the salt. Salt buoyancy (SB) usually acts upward and has the tendency to accelerate and decelerate the vertical overburden stress above and below the salt respectively. Therefore, the maximum principal stress (PS) is not necessarily represented only by the vertical weight of sediment, which known as the overburden (OB), but also by the addition of salt tectonic stresses (Figure 3). Therefore, calculating the principle stress (PS) as the overburden (OB) can lead to erroneous pore pressure prediction. It is observed that leak off tests (σ 3 / FP) above and within the salt is greater than the estimated OB. Moreover, within the salt body the pore pressure should drop to minimal due to the lack of porosity, permeability and fluid. The difference between FP and PP represents the drilling tolerance window (DTW) limits (Figure.4).

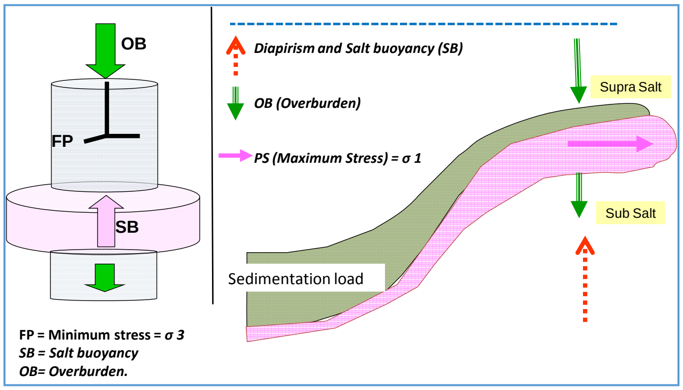

Figure 3: *Geomechanical model (on the left) shows the low-salt density impact on the subsurface stress vectors. On right, a dynamic model shows the impact of sedimentation on supra and subsalt stresses.*

In the extensional mini salt basins, located between the Sigsbee toe and the Shelf edge, the magnitude and direction of the maximum stresses are controlled by sediment load, salt thickness, and salt emplacement-displacement history. Lower pore pressure gradient has been observed below the salt and a higher gradient above the salt barrier (Shaker 2008 a)[3]. However, in a compressional system, the lateral stress generated by the salt movement acts as the maximum principal stress (PS), whereas the overburden (OB) represents the minimum stress (FP) (Figures 2 and 3). Keeping the mud weight in balance with the changeable formation pressure is crucial to complete a successful test. For a safe and optimum operation, the mud weight (MW) at the drilling bit level, which is referred to as Equivalent Circulating Density (ECD), should be restrained within the DTW (Shaker 2008b)[4].

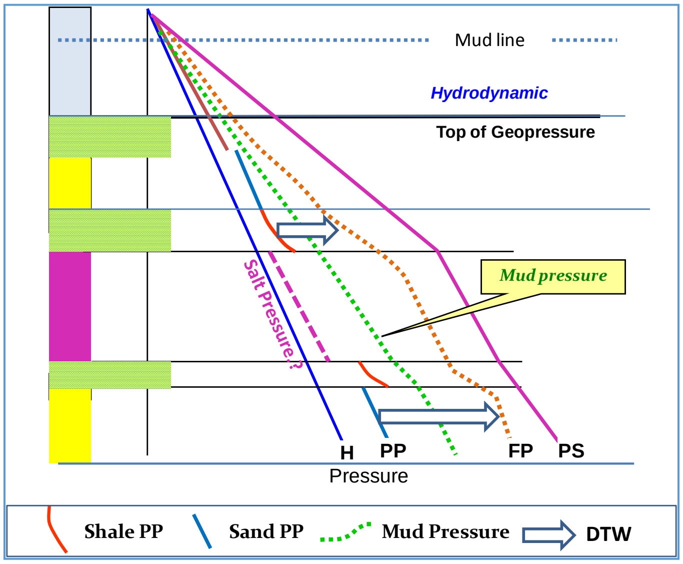

Figure 4: *Generic pressure – depth plot shows the pressure gradient in different rock types. Note pressure in salt is minimum due to lack of porosity and fluid. The blue arrow represents the drilling tolerance window (DTW). DTW below the salt is larger than the one above the salt.*

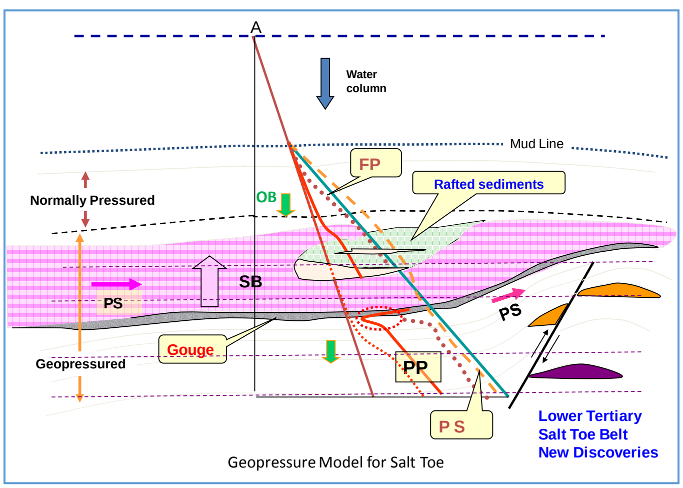

Figure 5: *Geopressure model simulate the behavior of the PP, FP and PS above, within and below the salt. PP, FP and PS show higher gradient above the salt, especially in rafted sediments, and conversely lower gradient below the salt. Note the strong retreat of PP and FP at the gouge zone.*

The generic geopressure model in Figure 5 is built based on the pore pressure analysis of several subsalt wells (Figure 1) in the mini basins area and the frontier Sigsbee belt. This model shows a distinctive difference between the PS, PP and FP above and below the salt. It exhibits the unexpected changes of the pore pressure within a salt mass with a rafted sediment intrusion. It illustrates the drastic drop of pore and fracture pressures at the salt-sediment interface (gouge) due to the presence of the sheared rubble zone.

Pressure transgression can be detected ahead of the drill bit from seismic velocity above the salt. However, within and below the salt, predicting such pressure kicks is tricky due to the poor seismic imaging. Pressure transgression (drilling kicks) can push the formation pressure envelopes to the proximity of fracture limit. Increasing the MW to overcome the excess pressure due to sediments inclusions can cause loss of circulation (LOC) and /or requiring affixing extra casing string to the well design (Shaker, 2008 b)[4]. .
On the other hand, a substantial drop in pore pressure (strong regression) at the gouge zone can lead to a considerable LOC. without mud return. Well bore bypasses and sidetracks are some of the common practices used to overcome these problems at the base of salt.

Case histories:

Several Miocene and Lower Tertiary (Wilcox) discoveries and fields have been found lately along the Sigsbee escarpments (Figure 1). Hadrian (Keathley Canyon), Jack, St. Malo , Cascade and Chinock (Walker Ridge), Mad Dog and Atlantis (Green Canyon), Neptune (Atwater Valley) fields are part of an emerging thrust belt deepwater Gulf of Mexico frontier play. Jack (Walker Ridge 758/759) and St. Malo (Walker Ridge 678) are two fields producing from the Wilcox (Eocene/ Paleocene) equivalent deposit. On the other hand Atlantis (Green Canyon 699) and Hadrian (Keathely Canyon 919) are targeting younger Miocene sediments (Figure1).

It has been observed that drilling some of these subsalt wells in this frontier area are very challenging to drill compared to the others. Examining the wire line logs, drilling records and mud logs of the Jack vs. St. Malo prospects (±15 miles apart) reveal a substantial lithological and borehole pressure profile disparity within their two salt bodies. Jack and St. Malo reservoirs share common characteristics, including: gross pay sections (> 1,000 ft), low permeability, large closures, and significant volumes of oil in place. However, St. Malo had the least operation's troubles because the well bore trajectory drilled through a clean salt body. On the other hand, the Jack well suffered several hurdles and was expensive to complete because it was drilled through a salt mass with several embedded sediments blocks.

Analogous to the aforementioned case, Atlantis vs. Hadrian Miocene discoveries exhibits the same phenomenon. Atlantis well #1 has suffered several severe LOC at the gouge zone and was side tracked twice with bypasses to overcome the challenge of exiting the base of the salt. On the other hand, Hadrian well #1 reached TD with minimum challenges.

Wells drilled in Wilcox

Walker Ridge 758 #1 (Jack Prospect)

The discovery Jack well #1 (OCS-G- 17016) was drilled in the year 2004 by Chevron Corporation in block 758 in a water depth of 7,100 ft. The top and base of the salt were tagged at a depth of 9,800 ft and 19,650 ft respectively (salt thickness 9,850 ft). The well reached total depth (TD) of 28,504 ft after it was side tracked several times and experienced several drilling hurdles to reach the subsalt Wilcox main objectives. An appraisal well, Jack #2, was drilled and tested the prospect in block 758 (OCS-G-17015) during the summer of 2006. A flow test was performed on the upper litho-stratigraphic unit (Wilcox 1). It flowed at a maximum rate of 6,000 BOPD with +/- 40 percent of the total pay section contributing. It is one of the most expensive wells ever drilled and tested world-wide. The majority of operation problems were confined to the salt-sediment interface, i.e. the gouge zone.

The geopressure model in Figure 5 implies the change of pore pressure due to the behavior of the maximum principal stress (PS) rather than the overburden (OB). It shows the pore pressure intermittent transgressions due to sediments inclusion within the salt and the substantial pressure regression at the gouge zone.

Figure 6 shows the analysis of the pore pressure indicator (ECD) and fracture pressure measurements (LOT Jack#1 well). This investigation validates the drilling challenges that took place during the operation of this well as follows:

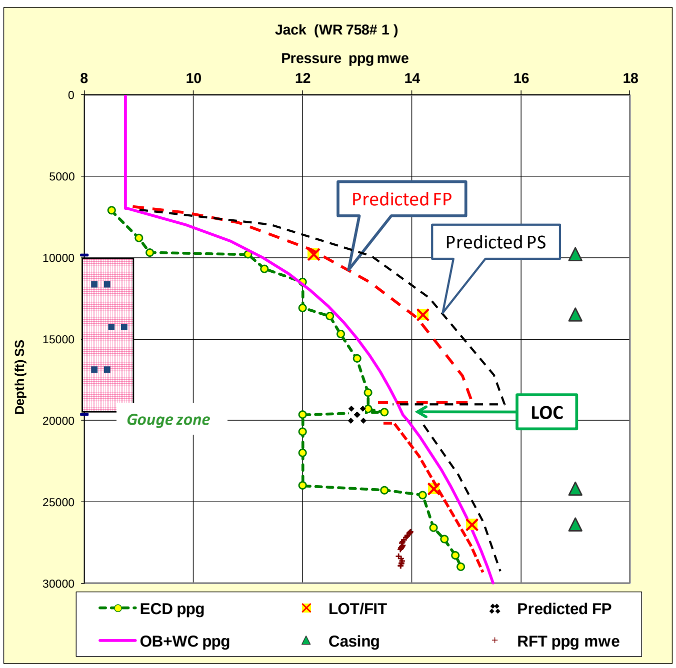

Figure 6: *P-D plot of WR 758 #1 shows PP (ECD) increase of ± 4 ppg drilling through the* **Dirty Salt** *(pink squares with dark inclusions). The LOT's (FP) and PS are greater than the OB above salt. The FP at the gouge zone is estimated to be 13ppg mwe where mud was completely lost.*

Mud weight (ECD) increased from 8.5 ppg to 9.2 ppg to drill from the mud line to the salt top (2,700 ft thick sediment). A trouble free window was adequate to set surface casing and penetrate the salt top at 9,800 ft (ECD was 11ppg and LOT of 12.2 ppg mwe).

Casing was set at the middle of the salt body (at 13,502 ft), due to the pressure transgression which pushed the mud pressure closer to the fracture pressure (ECD of 12 ppg was in proximity to the open hole last LOT of 12.2 ppg mwe). Pore pressure should not increase during the salt penetration if salt is clear from rafted sediments (Clean).

Mud weight incrementally increased due to frequent pressure kicks generated by rafted sediments and reached 13.5 ppg at the salt base (TD 19,650 ft). The immediacy of the MW to the FP at the salt base resulted in an extensive mud loss. Loss circulation material sweeps of 13.5 ppg were pumped several times, and failed to cure the bore-hole and stop the complete LOC. There was a failure to establish casing shoe and run an LOT at the salt base due to the bore-hole troubles and the inability to stop the excessive loss of circulation. Sidetracking was the only remedy to stop the loss of circulation and resume drilling below the salt to reach the Wilcox subsalt targets. Predicting a fracture pressure in the gouge zone of 13 ppg mwe as the result of the complete mud loss at the salt base.

MW was reduced to 12 ppg to resume drilling below the salt (Figure 6). This is in agreement with the model in figure 5 that shows a subsalt pressure regression is a common phenomenon in most of the subsalt traps. Two more casing strings were needed to reach TD and penetrate the pressured hydrocarbon charged pay zones. The upper one was at depth 24,200 ft with ECD of 14.2 ppg and LOT of 14.4 ppg mwe (narrow DTW). The lower one was at depth 26,400 ft with ECD of 14.4 ppg and LOT of 15.1 ppg mwe (average DTW).

Overall, the main reason for the unexpected boosting of ECD in the salt mass (to overcome the excess pressure kicks) was the presence of the encased sediment inclusions as rafted blocks in salt. These rafted sediments can be seen clearly on the Mud, SP and Resistivity logs. By the time the well bore trajectory penetrated the salt base; mud pressure was in proximity to or even exceeded the fracture pressure at the gouge zone. Therefore, drilling mud was completely lost.

Figure 6 shows the LOT above the salt is greater than the OB and vice versa below the salt. Moreover, PS is expected to be greater than the OB due to the salt tectonic. Predicted fracture pressure was estimated to be less or in proximity to the mud pressure (13 ppg mwe) where the complete LOC took place at the gouge zone.

The presence of rafted sediments in salt (Dirty Salt) is the driving mechanism behind increasing the MW that lead to a negligible DTW and complete mud LOC.

Walker Ridge 678 #1 (St. Malo Field)

The discovery Walker Ridge 678 well #1 (OCS-G- 21245) was drilled to test a Wilcox structural closure in water depth of 6,800 ft and about 15 miles offset Jack discovery. The top and bottom of the salt were tagged at depths 8,770 ft. and 18,784 ft. respectively (salt thickness 10,014 ft.). The well reached total depth (TD) of 29,012 ft with relatively minimal troubles compared to its analogous wells on the same trend.

The geopressure model in Figure 5, which indicates the change of pore pressure due to the behavior of the maximum principal stress, shows a drop of the pressure gradient below the salt. From a geopressure standpoint, the analysis of the pore pressure indicator (MW) and fracture pressure measurements (LOT) justifies successful drilling resuming of this well (Figure 7)) as follows:

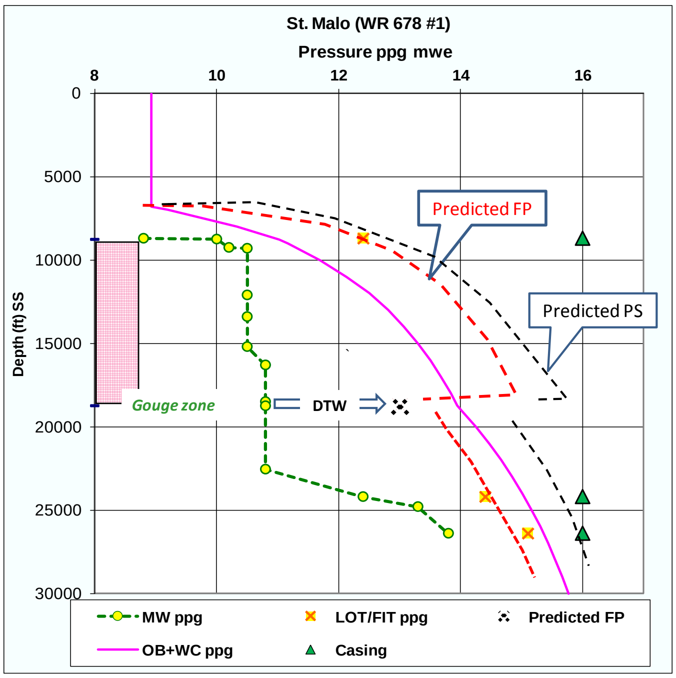

Figure 7: *P-D plot of WR 678 #1 shows a slight increase of MW of ± ½ ppg penetrating the* **Clean Salt** *and beyond. The MW (10.8 ppg) and the predicted FP at the gouge zone (13 ppg mwe) create an excellent DTW (± 2ppg). The lack of rafted sediments led to a minimum pressure increase throughout the salt (Clean).*

- Penetrating the salt top with drilling mud weight of 10.2 ppg and performing an LOT of 12.4 ppg.mwe allowed a sufficient 2.2 ppg drilling tolerance window to resume drilling through the entire salt body.
- A slight increase in the mud weight, (from 10.2 ppg to 10.8 ppg) took place during the penetration of the 10,014 ft thick salt.
- Drilling through the salt base (possible gouge) took place without loss of circulation. The on-hand mud weight of 10.8 ppg was adequate to drill the salt-sediment interface and reached beyond to depth of 22,553 ft within the Wilcox. This is due to the fact that the DTW at the expected gouge zone was 2.2 ppg mwe (13 - 10.8 ppg). The estimated fracture pressure at the gouge zone was 13 ppg based on Jack #1 correlative value.
- Two more casing seats with LOT tests were performed to reach the well's TD. The shallow one was at depth of 24,227 ft (MW of 12.4ppg / LOT of 14.2 ppg mwe) and a deeper one at 26,419 ft (MW 13.8 ppg / LOT 15.1 ppg mwe). In both cases the tolerance window was sufficient to drill safe and trouble free through the thick hydrocarbon column. Drilling through Upper Wilcox pay zones to depth 29,012 ft , mud weight was raised to 13.8 ppg to compensate for the increase of connection gas due to the presence of hydrocarbon.

Overall, three casing strings were needed to reach TD, without LOC and the maximum mud weight needed was 13.8 ppg. The drilling tolerance window along the trajectory of this well was optimum for a subsalt test. This is mainly because the bulk of the penetrated salt bed (about 10,000 ft) was free from overpressure pockets generated by sediment inclusion as rafted sediments blocks, i.e. Clean Salt. This allowed an optimum drilling tolerance window within the salt gouge zone and the deeper Wilcox (Figure 7).

Wells Drilled in the Miocene

Green Canyon 699 #1 (Atlantis Field)

It is one of the largest oil producing Miocene fields on this trend. The first wildcat was drilled vertically through the salt to test the prospect from surface location at GC 699 #1. Due to several severe challenges to drill through the salt, the development project was designed to avoid the salt mass and the development directional wells were drilled from GC 743 and 744 blocks.

This wildcat was drilled in 4,750 ft water depth, and penetrated the top and base of salt at 7,176 ft and 14,120 ft respectively. MW of 8.9 ppg was used to drill from the mudline to the salt top. Entering the salt, MW increased to 10.2 ppg and setting casing shoe at 8,620 ft with LOT/FIT of 11 ppg mwe (0.8 ppg mwe DTW). Several pressure kicks took place from depth 8,620 ft to the base of the salt which led to an increase MW to 12.5 ppg (Figure 8). Exiting the salt base with MW of 12.5 ppg resulted in complete LOC. This indicates that the predicted fracture pressure (LOT) of the gouge zone is less than the MW.

Several failed trials were conducted to heal the original bore hole. Sidetracks and bypass holes were successful in reaching depth 14,573 ft with MW of 12.6 ppg and performed LOT of 14.5 ppg mwe. To reach TD of 19,500 ft, MW was reduced to 12.2 ppg with LOT of 14.5 ppg mwe at TD (optimum DTW of 2.3 ppg mwe).

The pressure profile of this well (Figure 8) is in concordance with the proposed geopressure model for this trend (Figure 5). Fracture pressure is greater than the calculated density overburden (OB) above the salt and vise versa below the salt. Noteworthy, PS is represented by the salt thrust tectonic and not the OB. The gradual increase of MW within the dirty salt is the main cause of LOC at the gouge zone where the mud pressure overcomes the fracture pressure.

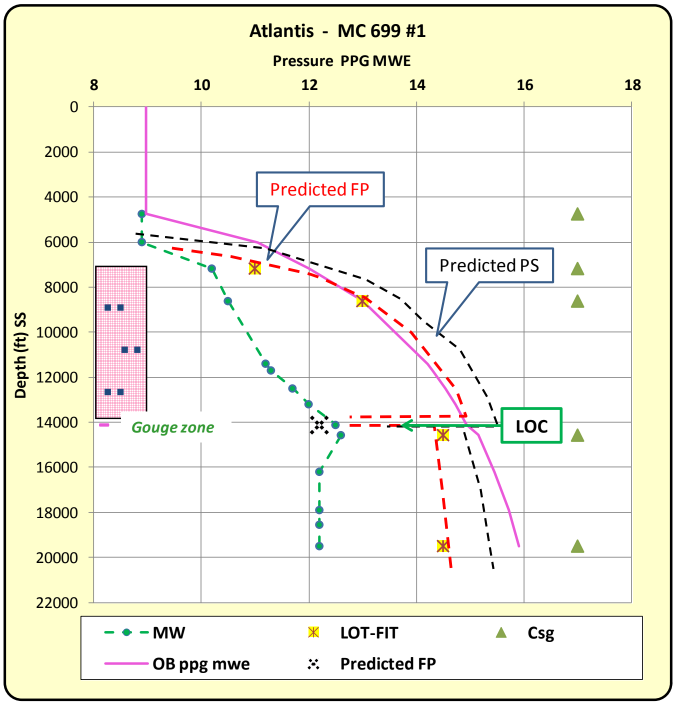

Figure 8: *P-D plot of MC 699#1 exhibits the MW increase of ± 3.5 ppg penetrating the* **Dirty Salt** *mass. A complete LOC took place exiting the salt with MW of 12.2 ppg. Predicted FP at the gouge zone is 12.2 ppg or less.*

Keathley Canyon 919 #1 (Hadrian Prospect)

It is a Miocene prospect. The discovery Well #1 in Keathley Canyon Block 919 was drilled in 7,315 ft water depth. The top and base of the salt was tapped at 9,300 ft and 18,550 ft respectively (salt thickness is 9,250 ft). Placed a surface casing shoe at 9,242 ft with MW of 10.5 ppg and penetrate the salt with the same MW. Predicted FP (LOT) is 11 ppg mwe using the Atlantis #1 as analogous, results in DTW of 0.5 ppg mwe. Drilling ahead to depth 12,750 ft took place with a subtle gradual MW increase to 11 ppg. Drilling ahead and exiting the salt-sediment interface (at 18,550 ft) and proceeded to depth 20,200 ft without changing the MW of 11.6 ppg (Figure 9).

The second casing point was placed at 21,000 ft with a MW increase from 11.8 to 13.5 ppg to compensate for the Pliocene-Miocene pay zones. LOT at 21,000 ft is 14.2 ppg mwe. The third casing shoe was set at 23,700 ft with LOT of 14.5 ppg mwe . MW gradually increased to 14 ppg at the TD of 27,975 ft. Mud pressure was in balance with the reservoir pressure (RFT's).

The predicted fracture pressure is 12.2 ppg mwe as equivalent to the Miocene gouge zone in Atlantis. Therefore, DTW is predicted to exceed 0.6 ppg mwe that allows penetrating the gouge zone and drilling ahead without setting extra casing. The non-presence of rafted sediments within the salt allow using MW throughout the salt, gouge and deeper without LOC or setting extra casing (Figure 9).

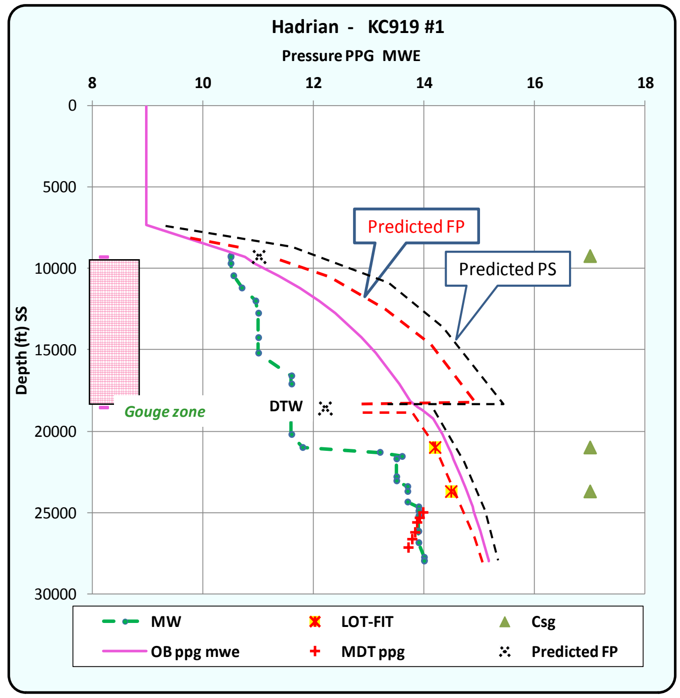

Figure 9: P-D plot of KC 919 #1 shows a gradual minor MW increase of *± 1 ppg penetrating the entire* **Clean Salt** *section. The predicted FP of 12.2 ppg mwe allow a moderate DTW (> 0.6 ppg mwe) and trouble free drilling at the gouge zone.*

Conclusion and Recommendations

The drilling challenges in the thrust salt belt (e.g. Sigsbee) become intricate due to the salt stresses perturbation. The sediments influx that cause salt thrust occasionally become trapped as rafted sediments. Moreover, salt movements toward basin plow the sea floor (older sediments) and create rubble-sheared zone (gouge). This leads to:

- Uncertainty of pre-drilling pore pressure prediction profile. Pre-spud mud and casing programs are contingent on the pressure prediction method.
- Salt tectonic is acting as the principal stress instead of the overburden. Therefore, the LOT measurements (FP) exceed the calculated OB above the salt above the thrust salt.
- Pore pressure and fracture pressure gradients are transgressive above the salt and regressive below the salt.
- The presence of rafted sediments in salt leads to an increase of the MW within the salt mass. Penetrating the gouge zone with high MW (greater than FP) can lead to extensive LOC.
- Drilling tolerance window in clean salt is optimum to drill through the gouge zone. On the other hand, it is negligible in dirty salt and causes severe LOC.
- A salt's displacement and emplacement history study is recommended before drilling to track salt source and movements. This can helps in guessing if the sediment influx was the main mechanism for the down-dip salt creeping.

- Reprocessing the seismic traces in the salt body to determine any presence of rafted blocks, so they can be avoided (Figure 10).

Finally, drilling through and below the Dirty Salt can be costly and sometimes lead to the abandonment of the whole project. The Drilling Tolerance Window dictates the well design, mud weights and the test's outcomes. Keeping the mud weight within the drilling tolerance window is crucial for drilling through the salt, especially in deep water thrust structures. More importantly, penetrating the gouge zone with overbalanced MW that is higher than the weak fracture pressure in the rubble zone is the main cause of complete loss of circulation at the Dirty Salt – Sediment interface,.

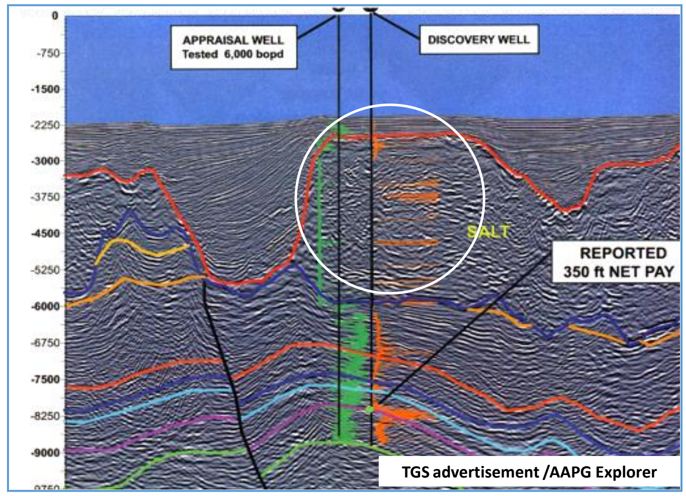

Figure 10: *A seismic display over Jack discovery (courtesy. of TGS). The bright seismic reflector events might be a response to rafted blocks. Note the sediments high resistivity curve (red log curve inside circle) concurs with the bright reflectors on the seismic.*

Acknowledgments

I am indebted to Paul Post for his appraisal and recommendation on the expanded original work "The Double Edged Sword, GCAGS 2008". Thanks also to the BOEM (previously MMS) staff for their generous online database.
I also appreciate the AADE committee for accepting this paper to be presented at the AADE 2016 conference. Special gratitude goes to Rusty Connell for his appraisal and suggestions.

Nomenclature

PS	= *maximum principal stress (σ 1)*
Shmin	= *minimum principal stress (σ 3)*
PP	= *pore pressure*
FP	= *fracture pressure*
FIT	= *formation integrity test*
H	= *hydrostatic gradient*
LOT	= *leak off test*
SB	= *salt buoyancy*
OB	= *overburden*
ECD	= *equivalent circulation density*
DTW	= *drilling tolerance window*
LOC	= *loss of circulation*
RFT	= *repeated formation tester*
MDT	= *modular formation dynamic tester*
ppg	= *pound per gallon*
ppg mwe	= *pound per gallon mud weight equivalent*
MW	= *mud weight*
Csg	= *casing*
TD	= *total depth*
ft	= *feet*

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