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A Methodology of Root Cause Analysis of Well Bore Failure and Lost Production Using the Well Information

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Abstract
While producing an oil and gas well, the Gulf Coast operators often lose production suddenly due to well bore failure. They often ask us to find the *root-cause* of lost production using the available well information instead of conducting a sophisticated rock failure modeling. In addition, the operators ask us to recommend a simple remedial completion in order to resume production. In this paper, we present a systematic approach to the problem of a well drilled in waters off Louisiana Gulf Coast to depths below 15000 ft. Following our methodology, for a case presented to us, we analyzed the following: (1) the formation rock material plugging the production choke and tubing, (2) the Well Logs, (3) the Cement Bond Log and the Variable Density Log, (4) the schematic of Primary Completion, and (5) the Well Production Decline. The results of our work lead us to conclude that the chain of events in this case begins with (a) high draw-down that leads to high rate of water coning or water encroachment upward (b) lack of cement bond allows the water into the producing perforations, (c) subsidence of formation begins with high rate of oil and gas production, (d) highly plastic shale from over pressured, under-consolidated seal above the perforations begins to move downward, and finally (e) the tubing fills up with shale and rock fragments and (f) the production is lost. Equipped with this analysis, we have recommended the following remedial completion: (1) ***squeezing*** cement in cavernous cavities in the failed perforations, (2) ***selectively*** re-perforating suitable zones with good cement support, and (3) ***calculating the shear stress*** for a safe drawdown equivalent to or lower than the shear strength of the least shear resistance material, that is, the shale seal above the pay zone. In short, the ***shale control*** rather than sand control in deep formations is the key to a successful re-completion.

1. THE WELL BORE FORENSIC METHODOLOGY

We divide our analysis into three distinct parts first and then connect the dots to arrive at the "root cause" of the well bore Failure. It is then that we make a well-planned remedial well completion or re-drilling recommendations. Our simple yet in-depth approach to the problems, as shown in Fig. 1, includes the following: (1) *Output* of the Reservoir System, (2) The *Reservoir System* itself, and (3) The *Input to the Reservoir System* and all the formations during drilling the well from surface to the reservoir.

Following the arrows of Fig. 1, in this work, we take the well operators' observation, failed samples of rock collected at the choke, separator, and records from the "production choke and separators" as an *output of the system.* This is where the operators observe the "symptoms or effects" of the well bore failure in technological as well as the economic terms. We ask the operators for the failed, produced solids coming from the perforations, which are caught at the choke, separators, drip pots, or elsewhere. These samples constitute the backbone of our Mineralogical, petro-physical, geothermal, geo-mechanical, geochemical, and well construction mechanical analysis. This is because from the reservoir depth these samples carry with them the signature of the *failed Reservoir System.* Of course, this is above and beyond the normal "*output*" information such as the production or production test date, daily production rate of Oil, Gas, and Water, gas lift (if any), total produced fluid, water-cut, oil-cut, flowing tubing pressure, casing pressure, choke size, API gravity, gas-oil ratio, gas-liquid ratio, barrels of condensate, barrels of water, gas re-injection, shut-in tubing pressure, temperature, etc. In fact, because a great deal of well information is gathered and monitored with time, continuously or discretely, they constitute a gold mine of information for time series analysis. This method of data analysis usually results in highly beneficial inferences. They mark the history of the events as to "what" happened to the well and "when" did they happen.

Now that we have a fair amount of information on the *output of the system*, we need to characterize the *Reservoir System itself*. To understand the reservoir best, we should treat the reservoir rock seriously and consider it a "material" that has undergone

some serious failure and lost production. Before the failure event, the *material* rock was preserved as whole core or the side-wall core. If these cores are not available for the study, often the available formation "cuttings" are suitable for the well bore forensic work.
We examine the rock "material" minerals thoroughly using X-ray diffraction, thin sections, scanning electron microscope, and energy dispersive x-ray. Often the information obtained from Petrographic analysis of Thin Sections will prove sufficient when we add the experience factor to interpretation of data. Besides these material samples we often examine the pressure build-up or draw-down, reservoir limit tests, subsurface geological maps (stratigraphic-structural-combination structural), seismic sections, core data (water saturation, porosity, and permeability, grain size distribution, pore size distribution), capillary pressure, water-oil-gas contacts, distance to the faults and boundaries, fault strike, fault dip, well logs, etc.

At this point, we turn our attention to the *input* to the reservoir. Naturally, drilling data, or what we actually "do" as an input to the formation of interest, become extremely important to our analysis of the well bore failure. In this regard, we consider the "act of drilling" *as destructive testing of the rock material.* Specifically, we thoroughly examine the drill-time log, gas count, pore pressure, mud weights, cement-bond log, variable density log, and cutting samples. Additionally, we study mud logs, daily recap, bit records, mud hydraulics, well trajectories, well surveys, casing depth, casing shoe tests, and leak-off tests.

The reader might ask that *input, system, and output* data are too much to analyze. In fact, often we connect the "dots" together and arrive at the "root cause" using only a fraction of data we collect. We use the remainder as backup for further correlation works.

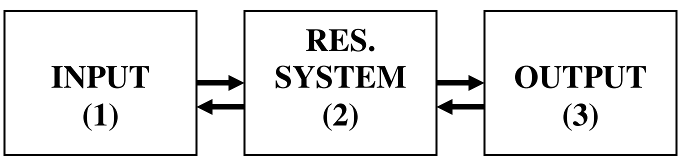


Fig.1: The Well Bore Forensic Methodology of Total System Approach to solving the well bore failure issues [1].

2. STATEMENT OF PROBLEM: A GULF OF MEXICO CASE HISTORY

The well operator asked authors to conduct a study of the perforated interval of a Gulf Coast Well data in detail and present opinion as to the root cause of wellbore failure, the "C" sand. Furthermore, the operator asked us to determine whether (a) there is another zone within the same sand members suitable for completion and (b) if the "C" sand can be brought back to production. The operator has completed "C" sand in xx271'-xx276' Measured Depth interval. *The main problems encountered in this well were well-sanding, water production, and sudden loss of gas production shortly after employing a certain water shut-off technique.*

2.1 Output: Analysis of the Symptoms

For our study, the operator provided a "bucket" of solids recovered from the surface choke. Fig. 2 shows the sample as received. Upon observing and examining the sample, we found several interesting features. The first one that caught our attention was the presence of crystallized salt formed at the surface of the sample. We measured the "salinity" of a liquid portion of the sample. We found the salt content to be approximately 250,000 PPM. This information is essential in calculating the specific weight of the water because it will lead to the correct pore pressure within the sand. Secondly, we found a host of geysers-like cavities formed at the surface. Obviously, the formation of the geysers was due to ***gas liberation***. The interesting part of this observation was that the sample continued, and as of writing of this paper, continuing to liberate gas. The third observation was that upon XRD analysis we found little or insignificant amount of swelling clays such as *smectite* and mixed layer. We recovered a fair amount of large sized formation material for further analysis from this "output bucket". Of interest to us was the amount of "absorbed-adsorbed-dissolved gas" and the rock cement fragments we collected. In our ***well forensic***, this was the first step we took toward "connecting" the dots to the root cause of the well bore failure.

Fig. 2: Material received from the operator as collected from the choke and separator. The salt content is in excess of 250,000PPM

Following the chain of evidence, we prepared Fig. 3. It depicts microscopic petrographic thin-sectioned view of a failed cement fragment recovered from the choke and the "bucket" sample. The length of this casing cement fragment is 6 to 7 millimeters. Fig. 4 shows the physical appearance of this cement prior to thin section preparation (see the third rock fragment from left in Fig. 4). The sample was impregnated with blue epoxy at low vacuum pressure; therefore, all effective pores and micro-pores would be impregnated with blue epoxy resin. The importance of this figure is founded in the fact that "failed cement" leads to water production.

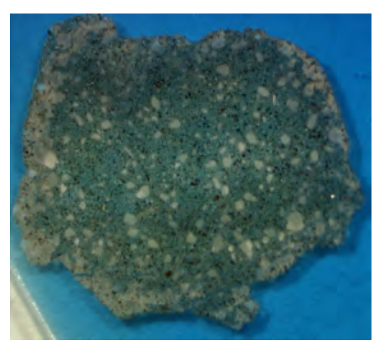


Fig. 3: Thin section of a failed casing cement recovered from the choke.

To examine the evidence further, we analyzed the remainder of shale fragments shown in Fig. 4.

Fig. 4: The third fragment from left is a failed casing cement fragment. The rest are shale fragments.

In addition to the failed cement, we show a particular peace of the "failed" shale in Fig. 5. In fact, it is our belief as borne out by evidence and experience that most well bore failures happen at the boundary interface of sand and shale. This observation makes the *"shale" control rather than "sand" control* of utmost importance in primary as well as the remedial completion.

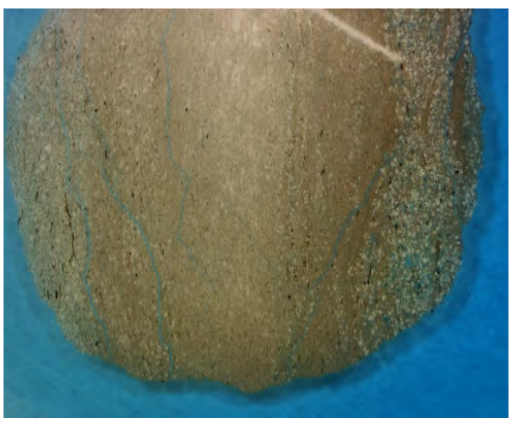


Fig. 5. A failed shale sample from Fig 4.

Thin section photomicrograph of Fig. 5 shows the largest shale fragment seen in Fig. 4, after it was thin-sectioned. The above shale fragment is about 10mm thick and it is made of thinly inter-laminated silt and clay (brown) laminations. The micro-fractures in this shale are dehydration micro-cracks generated after sample was dehydrated with 95% isopropyl alcohol at room temperature prior to thin-sectioning process. The micro-pores in the silt laminations have been impregnated with blue epoxy. Considering the general classic works on the effective stress theory and a normal effective stress at True Vertical Depth [2, 3, 4, 5] this particular silt lamination should not have this relatively high value of porosity. In fact this failed shale sample should have been impermeable to the blue epoxy resin. The facts that the clay laminations are not naturally dehydrated and the primary intergranular pores and micro-pores in the silt laminations are preserved indicate that the failed shale fragments come from an *originally over-pressured and under-compacted, under-consolidated zone*. This is where the ***Reservoir System*** porosity, permeability, rock failure, and other rock characteristics become ***extremely sensitive*** to the rate of fluid withdrawal and decline of pore pressure with time. We should keep in mind that other stresses and pressures such as swelling pressure, osmotic pressure, capillary pressure [6], dissolved gas pressure in the absorbed/adsorbed, and their time dependent properties, must be taken into account. In fact, our field experience shows that the lack of cement bonding to shale or the failed cement of Fig. 4 could be attributed to the gas adsorbed/absorbed on or to the shale or the gas dissolved in the shale adsorbed/absorbed water. The failure of "protective cement sheath" often appears at sections where the ***Neutron Porosity log indicates "higher than normal porosity" in shale sections, above or below the perforated zones.*** We shall discuss the evidence for this observation when we present CBL/VDL data in the discussion of ***Input.***

2.2. The Reservoir System

(i) Analysis of the Reservoir Rock**.** In Fig. 6, we show the rock samples produced from sand "C" and later cleaned them for further detailed microscopic analysis. We recovered these Reservoir rock fragments from the "bucket" shown in Fig. 2.

Fig. 6. Samples of failed Reservoir rock.

The Sandstone sample seen in Fig. 7 is a photomicrograph of a typical sandstone rock type recovered from the choke. We describe this sandstone as very fine to fine grained, well sorted, slightly clayey to relatively clean, porous sandstone with good reservoir rock quality. The primary intergranular pores are well preserved and are effectively interconnected. Some chemically unstable sand grains have been leached out completely, creating some oversized secondary pores scattered throughout the sample (yellow arrows). In this sample, the Silica quartz cemented some patches of sand grains tightly through quartz overgrowth and pore-filling mechanism. Black arrows point to two patches of silica-cemented sands. In a few of the sandstone fragments, not seen in this figure, the porosity in the entire fragment was lost to silica cement and porosity was only limited to secondary dissolution pores. This phenomenon indicates that the secondary dissolution pores post-date the irregularly distributed nodular patches of silica cementations. The pore system in general is relatively clean and free of migrating clays and swelling clays. The potential for formation damage by severe loss of permeability induced by incompatible fluids is minimal for these sandstones. However, the fluid compatibility of the ***shale beds*** is different from that of sandstones. Neutron porosity log shows that some of the shale beds at the Sand horizon are somewhat hydrated despite the relatively deep True Vertical Depth. Water analysis showed that the total dissolved solids in the produced formation water is in excess of 250,000ppm, as mentioned in

Fig. 2. Using low salinity water such as seawater may increase the chance of destabilizing the shale beds.

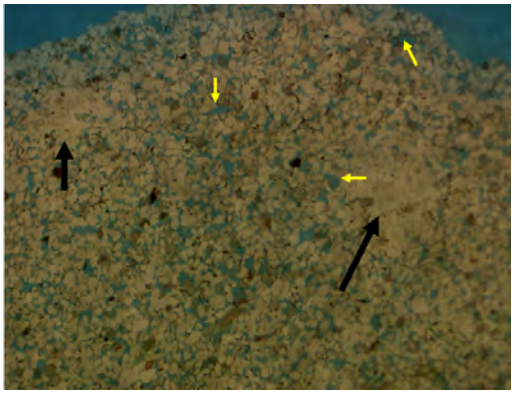


Fig. 7. A Reservoir rock taken from the samples of Fig. 6 for thin-section analysis of sand "C".

Upon observing the presence of the silica cement connecting sand patches of Fig. 7, we decided to investigate the "grain cementing mode" further. The Scanning Electron Microscope (SEM) image of Fig. 8 shows our further work. The figure presents the evidence of abundance of tiny secondary quartz crystals lining the pore system. We recovered this type of small crystals in the failed sandstone fragments recovered from the choke manifold. If we were dealing only with connate water saturated with silica ions, we would have expected euhedral quartz overgrowths, which form because of pressure dissolution at the grain-to-grain contacts only. It is believed commonly that overburden stress transferred to the grain contact points is the main reason for dissolution of silica in connate and pore waters. However, in these sandstones, as shown in Fig 8, we see variety of post-depositional secondary authigenic quartz developments. This phenomenon probably means that beside the interstitial connate water some free water has also been available in this rock to facilitate relatively extensive natural quartz overgrowth cementation.

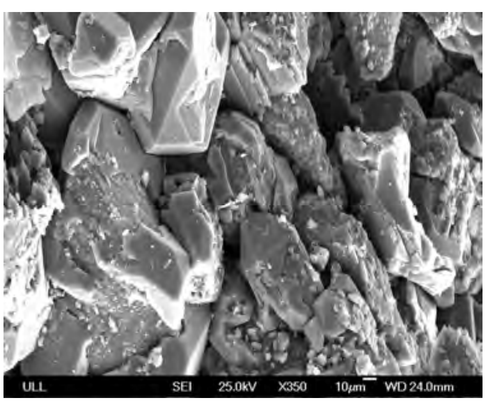


Fig.8. The Scanning Electron image of "pore filling" In addition "authigenic" quartz overgrowth.

Upon observing some micro-fracture in Fig. 8, we decided to investigate the rock failure mode of sand "C". Fig. 9 shows the area of interest to us. The rotated, oriented, and arc-like sand grains suggest the Reservoir rock failure is due to the effects of Reservoir subsidence. Interestingly, this is where we find a large number of fractured Reservoir Rock grains not shown in this image.

(ii) Analysis of Log and Production Decline Data. The completion plan places the sand intervals at xx271'-xx276' MD ("C" member), xx201'-xx240' MD, ("B" member) and xx140'-xx146' MD ("A" member). We carefully studied the data we offered the following opinion

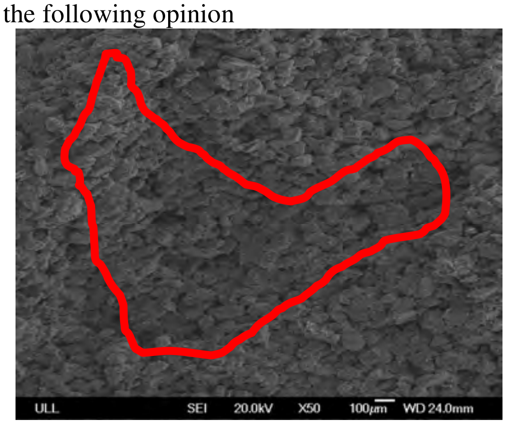


Fig.9. A failed Reservoir rock fragment produced from the perforated section of sand "C".

(a) The best quality reservoir is found within the top section of "C" sand where data indicates a strong Density Porosity-Neutron Porosity cross over with much higher true Resistivity than other sands. Our analysis of True Porosity of this section indicates that in this particular zone, on average, the porosity is about 25 percent. The porosity plot along with True Resistivity data for this sand is shown in Fig. 10.

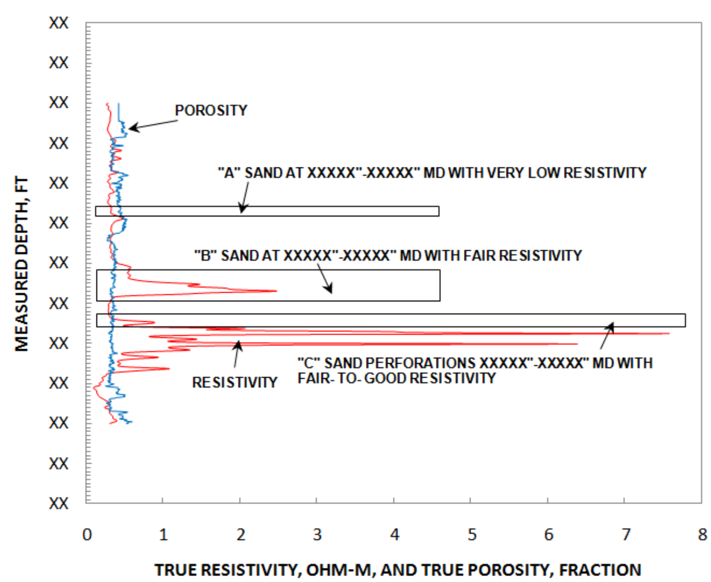


Fig. 10: Resistivity and Porosity of all sands.

(b) We have provided the porosity crossover plot, which commonly serves as a method of locating "gas" rich pay zones. This is shown in Fig. 11. The interesting feature of this figure is the "shale" section immediately above the sand "C" where shale appears to contain an unusual amount of water.

(c) Comparing the high water saturation in shale with the water saturation in sand "C" we find sand "C" S_w is less than 50 percent. We show the water saturation profile in Fig. 12.

As far as the probability of the hydrocarbon production is concerned, by far the "C" sand member is the best among other members. However, because of the high amount of water in the shale lying immediately above the "C" sand, we cannot make the same claim for the stability of the well bore or the perforations in this particular sand. Furthermore, a close examination of Fig. 12, and keeping Figures 2, 3, 4, and 5 in mind, leads the authors to suggest that the failed shale and cement samples shown in these figures are most likely from "C" zone. We show further evidence in support of our observation when we discuss the ***Input*** data.

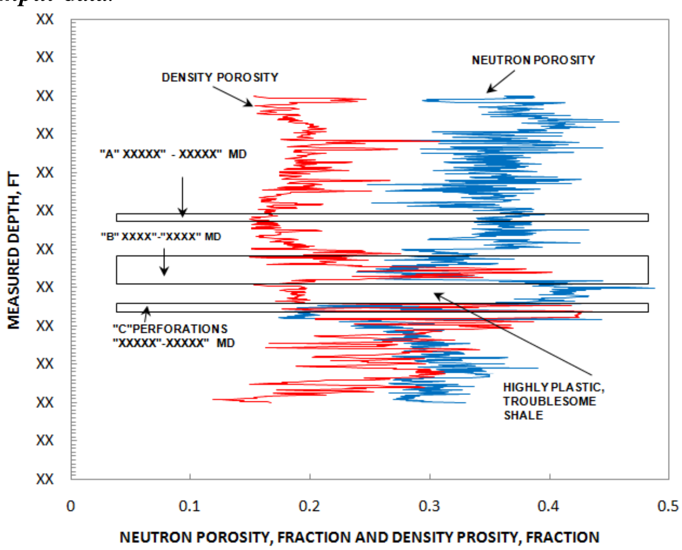


Fig.11. Neutron and Density porosity crossover plot of all sand

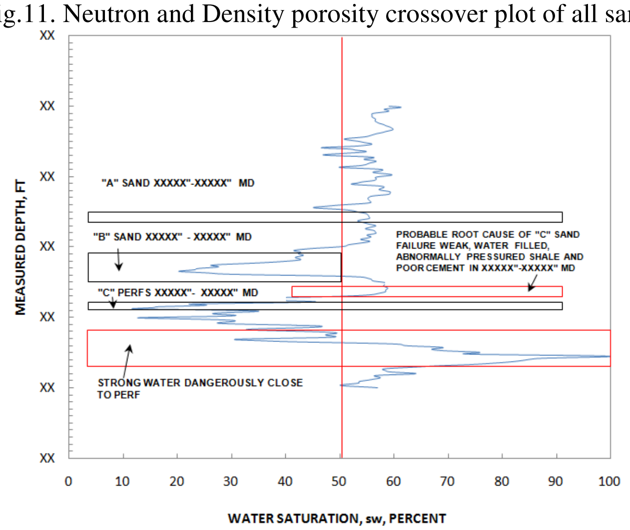


Fig. 12. Water saturation profile of all sand members.

(d) Finding the evidence of "high" water saturation and high pressure water zones near the failed sand "C" perforation prompted us to examine the trends of compaction-consolidation for all formations. Fig. 13 shows the porosity plot with measured depth. The concept of effective stress theory mentioned previously teaches us that for small strains *the time rate of change in effective stress is equal to a factor multiplied by the change in formation pressure (pore pressure) with respect to thickness of the sand, where the thickness of the sand is based on the True Vertical Depth of the sand.* The small strain here means actually *small changes in porosity or void ratio.* Now within the context of *"highly water saturated weak shale" lying above and below the "C" sand, it should be obvious that a "high rate of pressure and production decline" must lead to mobilization of shale/cement/perforation tunnels toward the well bore, thus causing "lost production".*

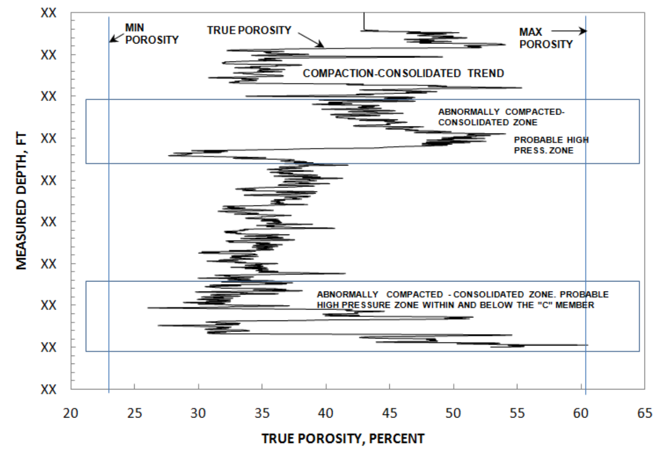


Fig.13. The Formation consolidation-compaction trend.

2.3. The Input.

In our well forensic methodology, we take the "input" to be what we do to the well. A glaring example of what we "do" to the well appears in the well production history in the form of the high rate of withdrawal of fluid from the "C" sand. According to the effective stress theory, the "fast" rate of withdrawal of the fluid, a fluid that "used to support" the weight of the formation above it, is analogous to "pulling the rug" under the "C" sand and allowing the shale/cement/rock to mobilize and move towards the casing. This tremendous force alone could collapse the casing.

Fig. 14 shows the production decline curve of "C" sand.

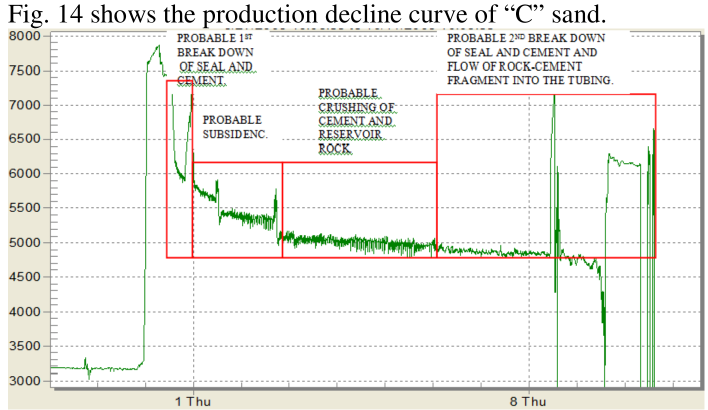


Fig.14. The "C" sand production record.

The important features of this figure are: (1) the steep slope of the decline at the beginning of pressure decline and sudden pressure and production spike that follows. This constitutes the first "symptom" of subsidence (time dependent settlement) of the "C" sand and the first probable break down "shale seal" and "cement sheath". (2) The well bore subsidence slowed down a little followed by two spikes. The rate of settlement in this period is lower than the initial rate. (3) The "C" sand failure rate was naturally modified probably through friction. (4) The gas and condensate production declined rapidly and we received the "bucket" sample of Fig. 2 for our study. The type of data shown in Fig. 14 constitutes a time-series data. We are able to drive a host of significant information from time-series of the well through Fourier analysis or various types of suitable transforms [7].

The next piece of evidence we analyzed were the well logs. Fig. 15 shows the well log. The well log shows all three members, A, B. and C. The most important piece of information regarding the well bore failure is the quality of shale lying above the “C” sand. Comparing the Neutron Porosity (the blue trace) immediately above the “C” sand with the shale above “B” and “A” members reveal that the shale above “C” contains a much larger proportion of water than the shale above “B” and “A”. In fact, it appears that the shale above “B” is much “different” from the other shale sections. *The shale we received several months ago, Fig. 2, as of the date of writing this paper, still contains a high amount of water and still is liberating gas.*

The continued gas liberation from the shale sample, suggests that the “cement” should “bond” very little or should not “bond” to it at all. Following the chain of evidence and, in order to find further supporting data regarding the “flowing failure” of the highly plastic (gumbo) shale and the subsequent “C” sand failure, we analyzed the Cement Bond Log and the Variable Density Log from this well.

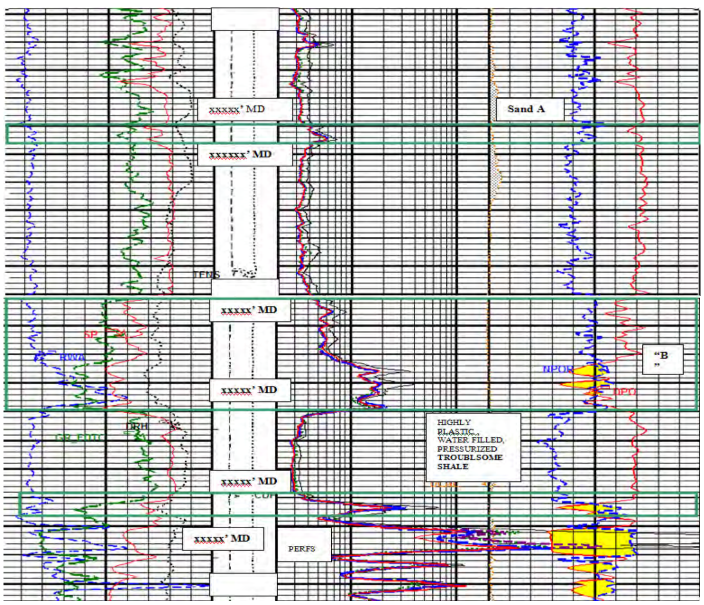


Fig. 15: The Well log from a well in Gulf of Mexico.

Fig. 16 shows the CBL/VDL data from the well in question. The important features of the data, which support our previous failure analysis, are: (1) the red arrows above the “C” sand point to CBL where there is “little” to “no cement bond” to the casing and (2) the VDL shows little “cement” bonding to the formation. The reader may recall that the red arrows above the “C” sand in this figure definitely point to the highly plastic (watery gumbo shale) “gassy” shale in showing high Neutron Porosity in Fig 15. In short, this evidence pinpoints the “failed shale” flow path toward the “C” sand. And, this concludes our well forensic analysis set forth in Fig. 1.

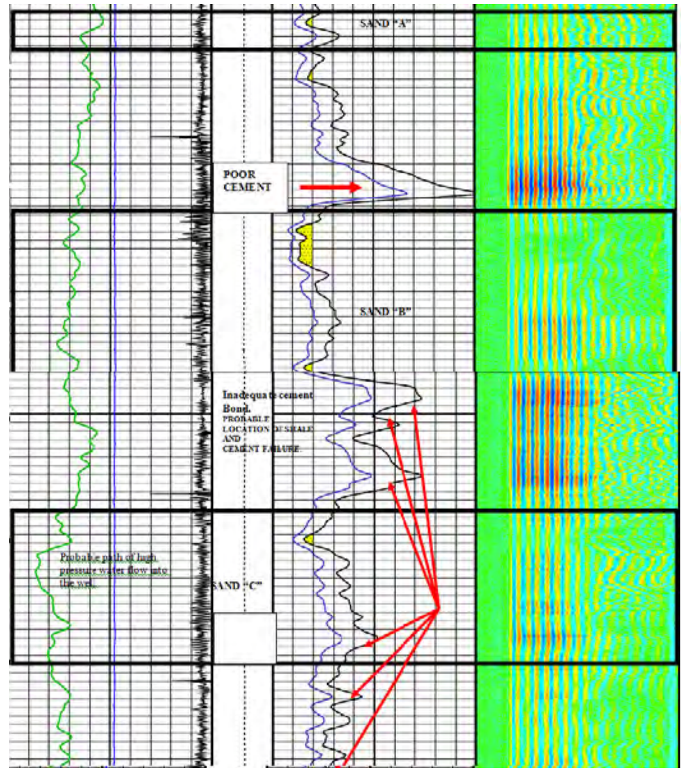


Fig. 16. The Cement Bond Log/Variable Density Log

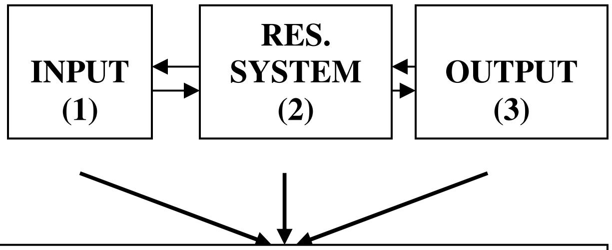
3. CONNECTING THE “DOTS”: THE ROOT CAUSES OF WELL BORE, THE “C” SAND FAILURE.

Our well bore forensic points to the following:

3.1. Figure 1 presents the protocol for well bore forensic analysis. We follow the protocol from right to left.

- (a) *The output of the Reservoir System:* Figures 2, 3, 4, and 5 shows the fingerprint, the output of the failed system as seen and collected at the choke, separator, or sand pot.
- (b) *The Reservoir System*: (1) Figures 6, 7, 8 and 9 show Microscope/ Petrographic Reservoir Rock Failure Analysis using thin section and Scanning Electron Microscope (SEM) and XRD/EDX analysis and (2) Figures 10, 11, 12, and 13 show Analysis of Reservoir Rock records within the context of Figures 6, 7, 8, and 9 . The combined analysis of (1) and (2) allows us to assess the Reservoir Rock Quality, (concerning Production of Oil an Gas) and Reservoir Rock Integrity (concerning the Stability or Instability of the Well Bore, Perforation Tunnels and Compaction – Consolidation Trend.)
- (c) *The Input to the Reservoir System:* Figures 14, 15, and 16 to analyze the Subsidence Rate, Time Series Analysis of production history, Integrity of Cement and acquiring other pertinent information on the formation damage and specifically, for example, creep-flow of the shale.
- (d) *Arriving at the Root Cause of Well Bore Failure and Lost Production using the Well Information:* We merge all the information,

thus far analyzed, in Figure 17. In this manner the "root" cause of the failure becomes apparent to the operator and Well Bore Forensic ™ analysts.



The Root Cause(s) of "C" Sand Failure:

1. Cement Bond to the casing and formation is either very poor or non-existent.
2. A highly water saturated, plastic, weak, gassy Shale is present immediately above the completed zone.
3. The highly pressurized water leg at the bottom of "C" sand subjects it to the danger of water coning and its consequences.
4. The high rate of fluid withdrawal from the "C" sand causes the perforation tunnel to breakdown. This could pull the shale downward to the perforations. This phenomenon alone could result in subsidence and settlement of the sand, which leads to the lost production, porosity and permeability.
5. The Well placement, Well Planning, Drilling, and Completion protocols in this sand do not consider the importance of effective stress, tectonic stresses, and orientation of field stress tensors.

Fig. 17. A completed Well Bore Forensic Analysis.

4. SUGGESTIONS FOR RE-COMPLETION.

Based on the results of this study, we recommended the following:

4.1 Inspect the casing to see whether it is collapsed near the "C" sand perforation interval.

4.2 Locate the specific measured depths, using the Gamma Ray log, Casing Collar Locator, etc, for a possible *selective* completion in this interval.

4.3 Exercise caution to avoid re-perforation of both the "*high pressure water zone"* below "C" member and the "*abnormally pressured shale"* above and within this zone.

4.4 Our suggested perforation-completion for this interval is about 0.25-0.4" hole entrance, phasing 30 Degrees from each side of the Low Side axis, SPF 6-8, with Perforating gun oriented roughly E-W.

4.5 The Initial Drawdown should be kept below 200 PSI for the first week of production and increased by 25-50 psi every week thereafter until a maximum production of about one MMCF is reached. Pulling this formation at high production rate causes the failure of the shale above it and strong water coning upward from the high-pressure water zone below the "C" sand.

4.6 Exercise caution that the orientation of the Perforations are carefully estimated after studying the geological maps of this zone, with emphasis on locating the nearby fault strike and dip.

4.7 After inspecting the casing for finding whether the casing has collapsed, for this remedial completion, we recommend, "*expanding*" the 5-inch liner across the "C" member, assuming it is not collapsed and assuming it can be expanded considerably against the formation.

4.8 If this is not possible, we recommend running a 1 ½ inch tubing and packer along the 2 7/8" tubing in a dual completion configuration.

4.9 The water below "C" sand should be isolated from the hydrocarbon zone above and perforated, using a suitable packer. The purpose of this dual completion is to produce the water sand below the hydrocarbon zone thus allowing the water contact level either to remain constant while producing the hydrocarbon from the "C" member or allowing the water-hydrocarbon contact to drop by at least one foot. We envision that such procedure would let the gas to be produced by expansion while mitigating the water coning due to hydrocarbon production.

4.10 The sand due to high salt content (250,000 PPM) is deemed extremely sensitive to low salinity water such as seawater. Therefore, we recommend properly designed weight brine weight CaBr2 for the coil tubing wash for recompleting the "C" sand.

4.11 The "B" sand located above the shale seal may have a potential to produce gas if allowed to flow at very low *initial drawdown*. It appears that there is no significant amount of water below this zone.

4.12 Analyzing the well data thoroughly for this study, we were not able to find any convincing reason for completing the "A" sand. The reason for this is that neither the porosity and water saturation nor the True Resistivity logs show any promise of production for this interval.

CONCLUSION:

Based on the evidence of well bore failure, we conclude that:

a. The High water saturation at lower sections and within the xx271'-xx305' measured depth plays an important role in shale failure. The perforated interval is in xx271'-xx276' MD.
b. High rate of fluid withdrawal from sand "C" could induce subsidence easily.
c. Our analysis of the high quartz overgrowth in addition to the presence of new quartz crystals corroborates the results of our water saturation model. In fact, we believe that the abnormal pressure due to high rate

of deposition, within and below “C” sand keeps the pores open thus leading to high porosity.

d. The CBL/VDL log, shows the existence of poor cement bond above the “C” sand. The high-pressure shale with high water content and dissolved gas obviously did not allow the cement to develop any significant bond to the casing and the shale formation (watery, gassy, gumbo shale.) We believe this is the source of shale and some small amount of cement fragments entering the well bore and tubing, after being broken down due to subsidence and water invasion. We attribute the cause of subsidence to producing the “C” sand at high rates. It appears the well was perforated without any strong cement supporting the casing. Actually, we do not see any evidence of any reasonable water isolation that cement is supposed to provide for protecting the “C” sand.

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