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Optimum Casing Design for Massive Salt Formations in Gulf of Suez

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Abstract

CSG collapse, or pipe deformation against salt formations in South Gharib and Belayim formations considered one of most known problems in GUPCO at 1970's. CSG design change over time using higher collapse rating, increase wall thickness and using of double concentric cemented casing against salts. This Paper will describe a practical methodology to estimate casing deformation problems due to salt loading. This approach allows changing field-casing design that was standardized in Gulf of Suez fields for more than 30 years from a double-cemented concentric casing string against salt bodies to a single casing standing alone. This approach greatly impacts total well cost, enhances well productivity, and provides room for future sidetrack opportunities. The methodology is based on calculating the casing deformation and comparing it to the clearance between the casing inside diameter and drift. An equation that calculates the magnitude of change in casing inside diameter due to salt loading will be developed based on previous literature and correlated to match the actual casing deformation incidents that happened in different fields and in different casing specs in the Gulf of Suez. Then the new modified equation and software model will be used to extrapolate the performance of a single heavy wall casing to stand alone against the salt section.

***Keywords**: Casing deformation; Massive salt formations; Optimum casing design; Developed equation; Future sidetracks; New opportunities.*

1. Introduction

Casing collapse or deformation against salt formations in S.GH and Belayim formation is considered one of the most common problems in the Gulf of Suez. Casing design changed over time using higher collapse rating, increase wall thickness and using of double concentric cemented casing against salt bodies. Since 1985, using double casing against salt formations has been proven effective to withstand production loads for many years. However, this casing design has the following disadvantage:

- No room for sidetracks except from Zeit formation inside the 13-3/8″ casing.
- Shallow injection points that decrease the well productivity or even not be able to produce at all in some cases so a big bore design is required to be able to complete the well with 7″ liner.

Recently Gupco have new many opportunities in many fields and a lot of them has not been economically f point due to existing well design where a 5″ liner is extended to shallow depths due to strategy of using double casings against salt.

This work will describe a practical methodology to estimate casing deformation problems due to salt loading. This approach allows changing Gupco casing design that was standardize in GOS fields for more than 30 years from a double-cemented concentric casing string against salt bodies to a single casing standing alone. This approach has great impacts on reducing total well cost, enhancing well productivity, and provides room for future sidetrack opportunities. The methodology that will be described in more details later is based on calculating the casing deformation and comparing it to the clearance between the casing inside diameter and its drift. An equation that calculates the magnitude of change in casing inside diameter due to salt loading has been developed and correlated to match the actual casing deformation incidents that happened in different fields and in different casing specifications in the Gulf of Suez. Then the new modified equation has been used to extrapolate the performance of a single heavy wall casing to stand alone against the salt section.

This new casing string that will be run in the hole will have its Ovality change over time recorded using wireline logging. These creep rates will be used to further validation of this methodology and estimate well life based on a finite element analysis model built using actual Ovality data. All the actual field data, equations, and plots used to evaluate different casing performances will be discussed feasible due to inability to deep sidetrack form existing wells and/or shallow injection

2. Literature review

Many researches been done on casing design against salts, this paper will discuss some of them as follows, Pattillo *et. al.* [1] shows problem in GOS wells like in Ramadan 5-16 and Ramadan 6-13 and July 29-32A having tights inside different configurations of 9 5/8" grades and weights (i.e. #40 N80, #43.5 N80, #47 C95 and #53.5 C95). Authors proposed three casing designs, 1-install higher grade casing V150 opposite to salts, 2-increase outside diameter 9.75" of 10 in, or to 3-run additional scab liner across salts, Weighing the advantages and disadvantages of the three alternatives listed above, the recommended order of preference is 3, 2, and, finally, 1. It is not clear that competent cement sheath can be placed opposite to salt on regular basis, so running 7" scab cemented inside 9 5/8" most preferable option.

Sheffield *et. al.* [2]) shows that to prevent or minimize casing collapse, minimum washed out hole should be drilled through the salt section so that the best quality cement bond can be obtained through salt section. Also proposed that Design casing for "worst case'' situation to include no packer fluid backup, nonexistent of cement sheath and non-uniform salt loading. This calls for a collapse casing design in order of 1.2 psi/ft. of depth plus a 1.125 safety factor or cover salt with two strings of casing.

Hackney [3] derived equation for additional tangential stress due to non-uniform collapse differential pressure over a limited extent of pipe circumference is given by:

$$\sigma_{salt} = \Delta P.\ D^2 \left(\frac{1}{162\ Dt_{min}} + \frac{K}{91}\right) \tag{1}$$

Also derived a related equation for the reduction in pipe due to elastic deformation for the same non-uniform pressure load:

$$\delta_{ID} = \frac{0.6\ \Delta P\ r^4}{Et^3} \tag{2}$$

By use of these equations, fair agreement was found with field measurements of casings in the previous data review. It should be noted that to get an agreeable with the field data available (he uses data of 71 wells). According to ID reduction equation as depth increases wall thickness must also increase to prevent plastic collapse. Relatively thin wall casing may be run across shallow zones. Since the reduction of inside diameter is dependent on the inverse of wall thickness. Large casings with tight clearances in wells where plastic formations are a problem, The tendency is to run casing with the minimum drift diameter for the next bit size. Often the casing is even "special drifted" to a diameter larger than the API drift diameter the tight clearance cause the elastic deformation of the casing to be more of a problem.

EI·Sayed *et al.* [4] this work is the third of previous papers in 1985 and in 1987, the authors stated different equations to calculate casing collapse resistance against salt. For Uniform loading, the resistance of the pipe to uniform loading is inversely proportional to d/h.

$$R_{p1}/R_{p2} = K_p \times \frac{(d/h)_1}{(d/h)_2} \tag{3}$$

where: Rp = pipe resistance to uniform loading, psi; Kp is the constant of proportionality.

For practical purposes, Kp can be considered close to I: Kp 1.034 for 7-in. casing and = 1.022 for 9 5/8-in. casing.

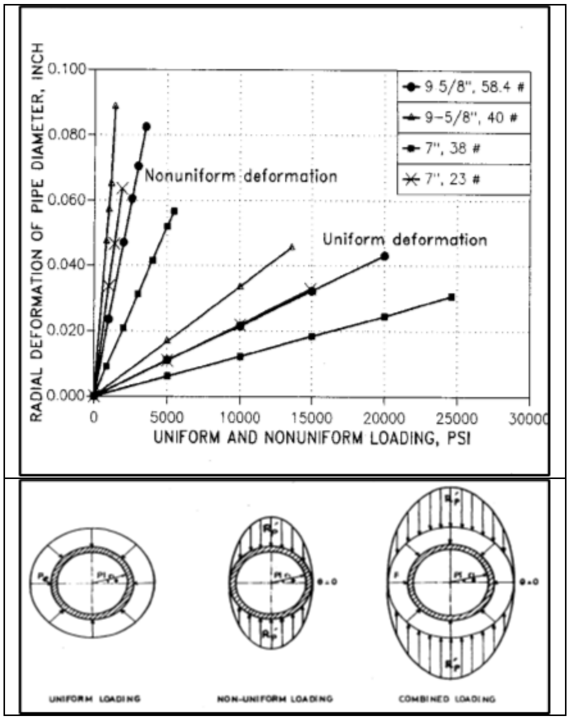

Figure 1. Relation between loading on casing and radial deformation for different casing size.

For Non-Uniform loading, under non-uniform loading, the radial deformation in the direction of the load is greater than that under uniform load so the resistance to non-uniform loading is decreased drastically as per Figure 1. Generally, the collapse resistance of single pipe under non-uniform load can be expressed in terms of its API collapse resistance, Rp, as

$$R'_P = K'R_p \quad (4)$$

where 0.11 (for 9 5/8”-in. casing) < K’ <0.27 (for 7-in. casing).

The resistance to the non-uniform load is inversely proportional to the square of d/h. For a casing size of the same yield strength and different nominal weights.

$$R'_{P1}/R'_{P2} = K_p \times \frac{(d/h)_1^2}{(d/h)_2^2} \quad (5)$$

where Kp can be considered equal to unity with an absolute error ranging from 0.2% to O.5%, which is negligible. Kp '= 1.005 for 7-in. casing and 1.002 for 9 5/8-in. casing.

Finally, they summarize that the radial deformation depends on the thickness of the casing, the modulus of elasticity of the cement, and the yield strength of steel. The resistance of the pipe to uniform loading is inversely proportional to d/h. At the point of failure, the value of the radial deformation depends more on the pipe size than d/h. The resistance to non-uniform loading is much lower than that to uniform loading. The reduction in loading resistance from uniform to non-uniform loading ranges from 70 to 85 %, depending on d/h. In the case of non-uniform loading, increasing pipe thickness is more effective in increasing the collapse resistance than raising the pipe grade, the radial deformation can be reduced by increasing casing size and/or the nominal weight.

Pattillo *et al.* [5] applied an FEA model to determine the reduction of collapse resistance in a casing after ovalization had occurred. Ovalization caused by non-uniform formation loading not only can in itself lead to unacceptable cross-sectional deformation, but it can also decrease the resistance of a cross section to more conventional loading by fluid pressure differential. A lower manufacturing ovality increases conventional collapse resistance, but decreases the imposed ovalization value at which non-uniform loading begins to reduce collapse resistance.

Coker *et. al.* [6] Authors develop a methodology for predicting salt deformation-influenced collapse resistance strength with proper logging techniques and further analyses and measurements, used to reduce the uncertainty around salt deformation and predict the economic life of existing wells. More importantly, new designs may be developed more confidently to improve well economics in these areas.

Zambetti *et. al.* [7] different configurations of Pipe-In-Pipe cemented casings tested in this experimental campaign show a general improvement in collapse resistance, both for the Uniform Loads and Punctual Loads. A FEA model is developed using full scale data as calibration, study allows combining uniform and punctual loads. The design formula presented in this paper considers the superposition effect.

$$P_{eq} = \left(P_u + P_p.\frac{K}{K_p}\right) \leq K(R_i + R_o) \quad (6)$$

where: P_{eq} is the equivalent pressure including uniform and punctual contributions; P_u is the uniform pressure used for design (Design pressure value); P_p is the punctual pressure used for design (to simplify assumed to be equal to P_u); K_u is the k-factor, evaluated from full-scale testing, under uniform loads (used 1.6); K_p is the k-factor, evaluated using FEA, under punctual loads (used 7.8); R_O is the outer pipe collapse rating; R_i is the inner pipe collapse rating.

The main results concerning the uniform loads applications, show the possibility to determine a real "K‟value equal to 1.6. The punctual load is more difficult to model, due to the intrinsic uncertainties related to the phenomena. The results show at worst case (cement damage, no internal fluids) equivalent K-factor close to 7.8 (which shows a resistance almost 5 times higher than the one under uniform loads). This activity will help assessing the effective loads acting on a string, identifying the cases where the two concentric cemented columns are an overdesign. Replacing the pipe-in-pipe assembly by an individual high collapse tubular leads to clear advantages in terms of costs, operations, complexity and optimal well section geometries.

3. Offset well data review

3.1. Collecting data from GUPCO wells

Casing deformation against salt formation considered a main risk in some fields, so data collected for wells that has collapse or tights inside casing separately and each time considered different factors that lead to problem (i.e. cement job, centralization, dog leg severity ...). Data collected for the study use previous collected data then fine-tuned and fill gapes to standardize data collection to see the complete picture based on all factors on the same level. Data showed in Table.1 contain some of wells that have tights inside casing due to different reasons showing data standardized to fit for purpose.

3.2. Casing collapse case history

Well A: The 9 5/8″ casing in this well [1]) Figure 2 was originally set at 10,873 ft. Primary cementing was accomplished in two stages. No cement returns were observed from either cement stage. During drill out, cement was found inside the casing at two locations-950 ft below the DV tool and 2,833 ft above the cementing shoe. Onsite calculations indicated that, for each stage, approximately 1,900 sacks of cement should have been displaced behind the casing. While drilling ahead at 11,402 ft with a stiff bottomhole assembly, and attempting to pull out of the hole, the drill string stuck at 10,330 ft. The drill string was backed off, leaving 160 ft offish in the hole. The fish was freed by bumping down and was subsequently lowered to TD. On an ensuing run with an 8 ½ in. bit, no obstruction was encountered. It was assumed that the previous problem was due to junk in the hole. Attempts to reengage the fish with a 7-in. overshot failed. While running an 8 ½ in. overshot, an obstruction was again encountered. A tapered mill was then run, and tight spots were encountered at 9,800 and 10,300 ft. The drill pipe again became stuck and was backed off. Fishing operations were unsuccessful, with the result that an additional 17 ft of fish were left in the hole. A casing caliper was run with inconclusive results. The well was plugged back and a window was cut at 8,800 to 8,857 ft. The well was sidetracked to 8,866 ft where another tight spot was encountered (8,715 ft). This time, deformation of the casing was confirmed by the caliper. The well was again plugged back and sidetracked at 7,270 ft. An 8.5″ hole was drilled to 11,687 ft and the well completed.

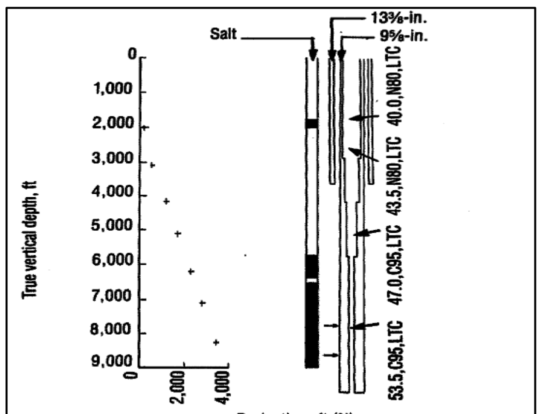

Figure 2. Well A. Wellbore sketch showing well deviation and TVD.

Table.1 Data collected from GOS wells.

Well name	Salt Fm.	Collapse Depth (ft TVDSS)	Angle @ collapsed depth	Temp @ collapsed depth (F)	Mud WT (ppg)		Drilled with OBM/WBM (Before)	Collapse pressure	casing yield Strgth (lb)	Had obstruction after (Days)	Calculated O.burden Grd (psi/ft) to collapse csg	Calculated O.burden Pressure (psi)
					While Drilling	After Running csg (min)						
Well A1	S.GH @ TOP 5910' MD	first point with condition BHA: 6700 Tri state mill BHA: 6343-6345 6423-6424 6512-6515 6685-6694 6790-6792 6818-6821 7588-7591 7674-7675	20 - 33 deg Dog leg: 2.23 to 0.3	193	12.5	9.2	SSM displaced to OBM after hit Kareem	10520	1710K	80	2.05	13,725
Well A2	S.GH	8415 8685	39.5	226	13.4	9	SSM	10520	1710K	10	1.72	14,458
Well A3	S.GH	7953 7620 7610	45-47	216	13	9 ppg while drilling displaced to seawater 8.6 ppg after c/o	SSM displaced to OBM before top Kareem	10200	1710K	16	1.73	13,755
Well A4	S.GH	7895 8232 8268 7306 WHILE RIH W/ SCAB	53	230	13.4	9.1-9.3 hole displaced to seawater 8.6 ppg after RIH w/ 7" LNR	SSM	10200	1710K	19	1.74	13,731
Well A5	S.GH	5346-5358 5215 5160-5165 5195-5205 5244-5247 5363-5370 5392-5398 5411-5414 5507-5547	6 TO 8	180	13.4	13.4	SSM	4800	3191K	107 DAYS FROM CMT IN PLACE @ 17/8/2002 TO 12/2/2002	1.56	8,665
Well A6	S.GH	4101 4717 5195 5306 5509 5412 5527 5900	26	192	13.3	9.1	SSM	10520	1710K	20	2.26	13,312
Well A7	Feiran	7448	44	220	13.8	9.5	SSM	4800	3191K	13	1.14	8479.312
Well A8	Feiran	7,473	29.5	220	13.8	9.8-10.1	ULTRA DRILL	10000	1477K	22 FOR BABA 26 DAYS FOR FEIRAN 8390' MD POINT	1.86	13924.8196
Well A9	Baba	7,807	22	220	13.6	9.5 - 10 ppg while drilling increase to 13.2 ppg after well control	SSM	10520	1710K	54	2.03	15878.7248
Well A10	Feiran	7,544	19.3	NA	15.1	13	SSM	7340	1477K	14	1.65	12439.744

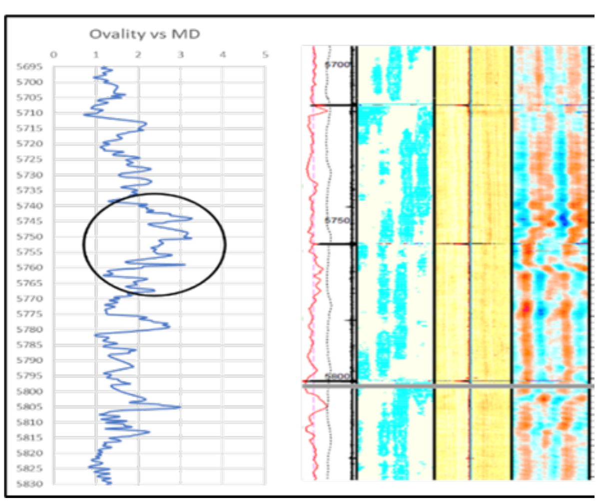

Figure 3. Well B. casing imaging log showing ovality due to salt movement.

Well B: After 20 days form running 9 5/8" csg, After reach 8 ½" hole csg point, while POOH inside csg Have obstruction at 6,307 ft (inside csg, lithology: Feiran salt) passed down with 25 klb s/wt and coming up with 20 klbs over pull, washing down with 200 gpm, observed pressure increased with 600 psi, tried 3 times no success. Casing imaging log was run in figure 3. showing ovality in 9 5/8" csg at obstruction depth due to salt movement. Work obstruction until smooth with 265 gpm (mini. Flow rate for motor) at 750 psi, 30 rpm @ 7 k ft.LB TQ circulate bottom's up @ 265 gpm @ 750 psi (while work string up & down), sample on shaker was LCM and collect 200 gram of steel from ditch magnet. Pooh with drilling BHA, RIH w/7" liner.

3.3. Wells have tights inside csg due to change in BHA stiffness case histories

Well C : While drilling 8 ½″ hole, after TCI bit quit, POOH to change bit to PDC bit, take tights while RIH and POOH, can't pass tights without TDS assist with 50 RPM and up to 30K O/P, however when change bit to TCI didn't observe any resistance and max O/P 10K while POOH. After that with many runs with TCI, decision to use PDC bit to drill to section TD, have the same problem, decision taken to RIH w/ milling BHA to smooth restrictions, to cont.' drill hole till TD using PDC.

Well D: While RIH with 8-1/2" steerable assy. Had 5 klb wt. @ 6020' (salt S.Gh , covered by 53.5 ppf csg), up and down with string through the depth several times with normal drag, Cont. drilling then POOH to change BHA with normal drag . Using Short Locked Assy. (8-1/2" PDC, 8-1/2" NBS, 6' SDC , 7-3/4" x 8-1/2" ADJ. STAB. , MWD , 8-1/2" R.R. STAB, 6-1/2" DC, JAR, 42x5" HWDP), RIH HAD WT 15 KLB @ 7295' (new point against S.GH salt), Cont. Drilling then While POOH had O/P @ 7,295' (S.Gh salt) move pipe Up/Down w/15 klb drag, Cont. POH, had o/pull @ 6,020' (S.GH salt) move pipe Up/Down w/25 klb drag (had same drag with pump off/on). Cont. POH to the surface. Change MWD probe. Break down bit. change bit to TCI, while RIH ream down f/5,700' - 8,590' w/ 120 rpm, 615 gpm @ 3700 psi & 300 amps, (TQ increase @ 5,934' & 5,972', made hard ream down/up f/6,023' - 6,025' and f/7295 - 7300'. cont. wash & ream f/7300 – 8,780' with normal TQ, no cutting on shakers. while reaming had contaminated fine junk with cutting on shale shakers. Cont. ream down f/8,590' - 8,780' (20' above top of window) with normal drag & no junk/cutting on shakers while reaming dn. pooh to change bit. RIH with new short locked assy. with new TCI, drill 8 1/2" hole to section TD without problems (using two runs), then RIH with 7" LNR.

Well E: The 8 ½' hole section drilled to TD @ 10,810 Ft ORKB without any problem related to casing collapse then while logging with E-line the tool stuck in open hole section in the third run, succeeded to strip over the tool and retrieve the fish. After that RIH for wiper trip before running the 7″ liner with the following BHA: (8 ½″ TCI. Bit (2-3-WT-A-3-I-NO-TD), 8 ½″ Near bit stab, 6 ½″ DC, 8″ String Stab, Float Sub, MWD, PBL, 6.5″ Jt DC, 6.5″ Jar , 6.5″ Jt DC, 24 Jt X 5″ HWDP) hile RIH with the above BHA without any problem inside casing, after that during POOH had 25 KLB O/P and 25 KLB (drag) inside 9 5/8″ CSG F/8072 T/8062' MD against Ferain FORMATION Figure 7 & 8 (INC 19° & DLS 0.37°), work through the tight until pass free. Then continue POOH had another tight spot @ 6543 ft. (inside casing in S. GH salt), with 25 KLB O/P and 25 KLB WT (drag), Work through the tight until pass free without rotation and pump off. Continue to surface (bit dull: 3-4-WT-A-3-I-NO-TD), Not mention in DDR any Marks on Stabilizers or bit. After that RIH directly with 7″ liner. The following concluded after studying BHA:

1. During dress off tie back sleeve with 7 7/16″ Polish Mill - 3X 5" HWDP - 8 ½" Water Melon Mill - 21X5" HWDP passed smoothly (in RIH or POOH) through the aforementioned tights without any problem.
2. The wiper trip assembly stiffer than milling assembly.

Well F: After POOH with 8 ½″ C/O assembly (dressing P&A plug for Sidetracking well), studying BHAs when finding obstruction in 9 5/8″ csg (Figure 4.) as follows:

1- 1st 8-1/2″ Gauging/scrapper (Gauging BHA)

While RIH with 8-1/2″ Gauging/scrapper (First Gauging BHA) to 8,639' RKB, had 10 KLB's slack weight, try to pass with elevator several times, no success. Connect TDS and ream down until have progress; work on smoothing obstruction by washing up and down with 600 GPM. Continue RIH to 10,040' RKB, had several tights in casing, smooth same and continue RIH. Work scrapper against 9-5/8″ whipstock setting depth. Perform wiper trip against tight points in casing had 3-4 KLB slack against point. POH with 8-1/2″ Gauging/scrapper BHA#25 to surface. (Tight points: 8,693, 9,730 9,768 9,809 9,851 9,889 9,925 9,970 ft-rkb.

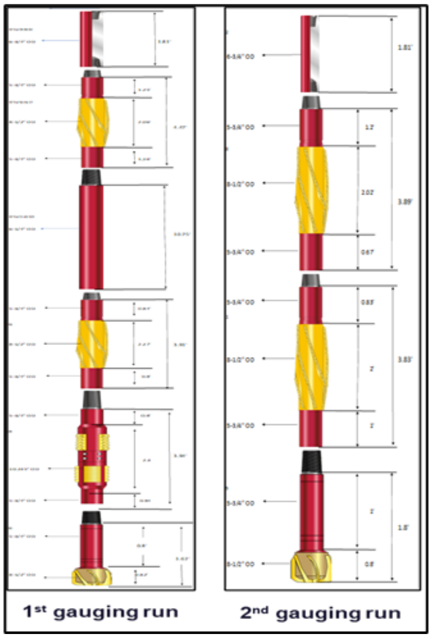

Figure 4. Well F Gauging runs while have obstruction

2- 2nd Gauging assy (L/D Pony Collar, Scrapper)

Had slack at 9,750′ RKB, wash down with 400 GPM and pass same. Had another 5 KLB slack at 9,871′, try to pass same with wash down but no success. (Tight points: 6,290 (against S.GH anhydrite) 8,250 8,640 ft-rkb. (two new points).

3- Whipstock windowmilling assy

RIH with Gyro and orient whipstock at 56 deg left and POH. Continue RIH with whip-stock/milling assy till tag bottom at 11,199′ RKB. Set whipstock, shear attachment bolt and start mill 9-7/8″ wind with 5-40 KLB WOB, 80-130 RPM and 500 GPM. Tight points: 9,868 9,912 9,952 9,992 ft-rkb.

Figure 5. Well F Obstructions happen at 9 7/8″ csg connection.

Conclusion

- 9 7/8″ casing connection ID of 8.541″ (Figure 5) compared to Pipe ID of 8.625″ caused the above deformation to happen at connection rather than body.
- Second gauging run was stiffer than first run which resulted in two new tight points and consumptions of mills before reaching 9-7/8″ casing.

3.4. Wells have Csg deformation due to change in Mwt

Well G : Problem depth @ 7953, 7620, 7610 TVDss, Had obstruction after 16 days, After using C/O polish dressing assembly (6" USED BIT, 7-7/16" POLISH MILL , 8-1/2" TOP DRESS MILL, FLEX SUB.), displace to sea water, flexing DP @ 2600 PSI, then While pooh had tight spot at 10490', 10007' and 9992'. In every spot could go up with 25/35 klb over pull and 20/25 klb S/O. Move string up and down in every spot, no change in O/P or S/O. Attempt to rotate but rotary immediately stalled out at 700 amps torque, Cont. POOH. Decision to RIH w/ 7″ Scab, no problem while RIH, the following notes on 9 5/8″ CMT Job:

- **1st stage:** Pump 237 bbl 15 ppg (G+35%sf) cement. Lost 60 bbl during cement job. Had 80 bbl losses during displacment. No spacer or cement return after open D.V tool @ 10176, CMT volume based on 100% excess over gauge hole (expected no cement against collapesd area).
- **2nd stage:** from 10170 to surface 371 bbls (1000 sxs + 35% SF+ 14% salt) 14.5 ppg lead slurry, 422 bbls 16 ppg tail slurry, no losses while pumping CMT, excess calculated 100% over gauged hole. Had 15 bbl losses while displacement.

Well H: Problem depth @ 7306, 7895, 8232, 8268 TVDss, Had obstruction after 19 days, After RIH w/ 7″ LNR and release running tool, reverse circulation at top of LNR then displace hole to sea water. RIH with 7-7/16" polish mill, 8-7/16" top dress mill, while reaming to tag TOL @ 11995' had hard reaming at 11833' & 11893'. Sweep hole no cuttings observed on shaker with high vis pill. While POOH took 50k lb's o/p at 11280'. Slack down 50k lb's weight on string could not move down. M/U top drive, start pumping with 300 gpm @ 250 psi with full circulation. Attempted to rotate string torque increased to 18k lb's and rotary stalled out and could not rotate string, slack down 70k lb's on string free down & free rotation. Back ream w/ 50 rpm @ 9k ft-lb's trq - string stall out at same depth 11280' and could not pass from this depth. Stop rotary and pull string to 90k lb's O/P - could not pass, attempted to rotate - no rotation, slack down - string free down at 150k lb's s/o wt and free rotation. Hard back ream with 50 rpm at 9-17k ft- lb's trq from 11280' to 11270' in 2 hr's till had free torque. Work string without rotation many times thru tight spot - pass with no problem. Sweep hole with 50 bbl's hi-vis pill while backreaming with no cuttings observed at shakers. Cont'd POOH with dressing assy from 11270' to surface. L/d 8-7/16" dressing mill & 7-7/16" polish mill. No junk marks on top shoulder or circumference of dressing mill and od still same (8-7/16‟). Had marks on bottom shoulder of dressing mill indicating work on top of liner. No marks on polish mill. Proceed to RIH w/ 7" scab LNR. While RIH took 15k lb's wt @ 10306' rkb, M/U top drive and satrted pump w/ 6 bpm @ 250 psi and attempted to pass washing down to tight spot @ 10306', slack down 20k lb's wt - could not pass, pick up string had 20k lb's O/P. Displace hole to brine water 9.8 ppg. Attempted to pass with liner from depth 10306' W/ 20K LB'S S/O wt with no sucess. P/U string with normal P/U weight. POOH w/ 7" scab liner from 10306' TO 8000' (above top of s. Gahrib salt). Wait to give time for brine water to effect on casing. Run back in hole with 7" scab liner on 5" D/P to 10250', wash down with 6 @ 250 psi and pass tight spot at 10306' with 5k lb's. Cont'd RIH TO 11890'.

4. Data analysis

4.1. Hydrostatic design: Calculated minimum external pressure vs TVD

According to Sheffield *et al.* [2], Design casing for "worst case'' situation to include no packer fluid backup, nonexistent of cement sheath and non-uniform salt loading. This calls for a collapse casing design in order of 1.2 psi/ft. of depth plus a 1.125 safety factor or cover salt with two strings of casing. However, by calculating minimum external pressure rating in failure and tights field data found gradient between 1.7 – 2.5 psi/ft. (same considered by Vallourec high collapse csg design for salt creeping).These values calculated from data collected in the previous section and applying equation:

$$P_{\min external\ pressure} = P_{collapse} + P_{internal\ hydraustatic} \quad (7)$$

From Figure 6 found that external load values of field data have different trend for TVD values 4,000 – 8,000 TVDss from that below 8,000 TVDss.

Applying overburden pressure 1 psi/ft against salt on stress check as usual show us that 9 5/8″ X 9 7/8″ P110 HC should be standalone as shown in Figure.7. However, data collected shows single casing does not standalone against salt even while drilling. By applying 2.5 psi/ft (as worst-case scenario uncemented and no internal hydrostatic pressure) shows the need for higher collapse rating casing up to 24,000 psi @ 10,000 ft.

	TVD	calculated external rating
SB 276-3	9079	1.78
	9195	1.77
	9197	1.77
	9185	1.77
	9171	1.77
R6-56B	6345	2.14
	6424	2.12
	6515	2.09
	6694	2.05
	6792	2.03
	6821	2.02
	7591	1.86
	7675	1.85
SG 310-11	8415	1.72
	8685	1.68
GS302-5	7953	1.73
	7620	1.79
	7610	1.79
GS302-6	7306	1.84
	7895	1.74
	8232	1.69
	8268	1.68
GS324-A5	5195	2.50
	5412	2.42
	5900	2.26
GS323-3	7473	1.85
GS323-4 & 4A	7807	1.87
LL87-4	7544	1.65
OCT A14ST1	6301	2.29
GS 373-4	6311	2.11
	7760	1.81
Lead-6	8069	1.78
	8470	1.72
	9343	1.87
	9372	1.86
	9403	1.86
	9934	1.79
	9462	1.85
	9447	1.85
	9479	1.85
	9489	1.85
	9521	1.84
	9508	1.84
	9537	1.84
GS 301-1B USIT	8400.00	1.71
	8600.00	1.68

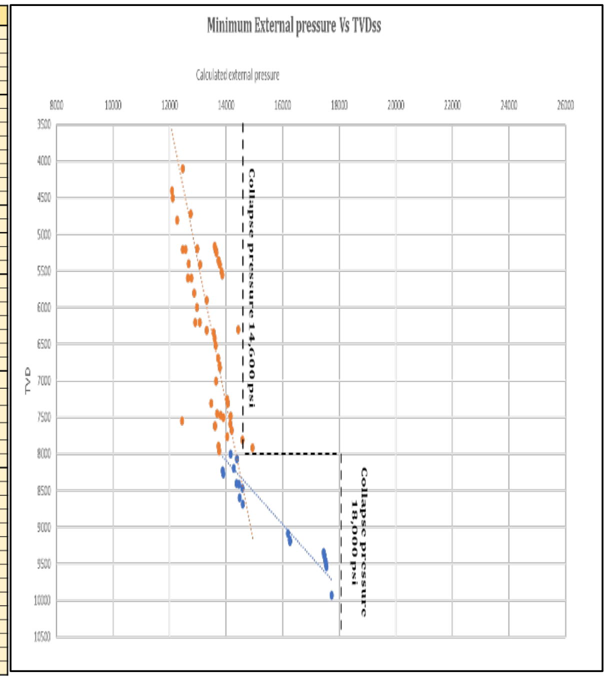

Fig.6. Applying hydrostatic design on GUPCO field data - Calculated minimum external pressure vs TVD.

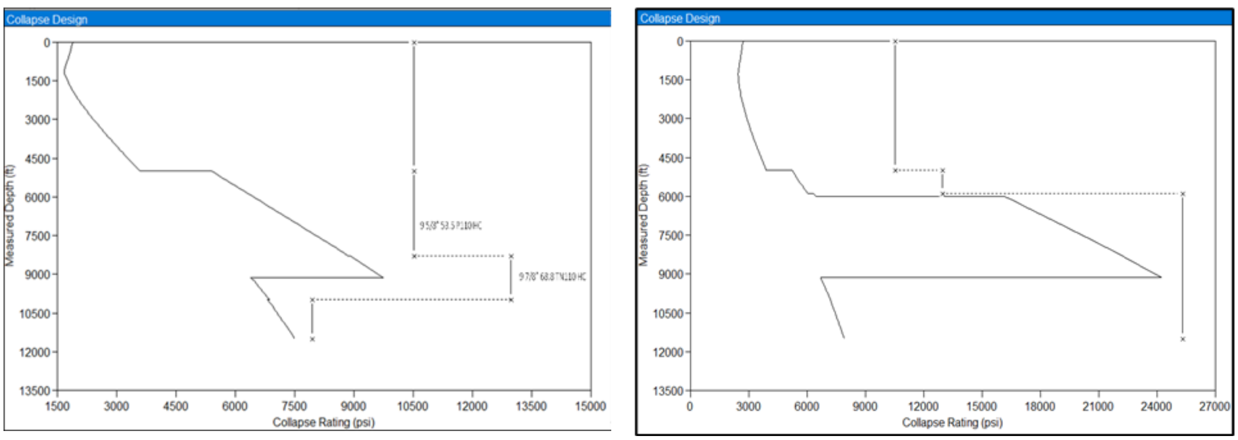

Fig. 7. Comparison of different hydraulic designs using STRESSCHECKTM.

4.2. New concept: Calculating Casing deformation against salt non-uniform loading

Applying the following modified hackney equation on 9 5/8" P110HC with tights inside casing conditions with the following assumptions, modulus of elasticity taken 30 Mpsi, differential pressure between o overburden pressure 1 psi/ft. and internal hydrostatic pressure at tight condition and most of these casing with bad cement job, values of casing deformation then compared with ID/drift clearance value, the following chart shows that all of points exceed the value of clearance which mean that tights should be encountered by using 9 5/8" casing which meet actual case.

$$\delta_{ID} = \frac{2.08 \times 10^{-4}\,(P_{OB} - P_{int.Hyd}) \times D^4}{Yt^3} \tag{8}$$

Also, by applying the same conditions on 9 7/8" and 7" casing found that values of deformation less than ID/drift clearance for depths less than 8000 ft. However, after 8000' TVD deformation exceed the ID/Drift clearance so tights in casing should be encountered and that meet real cases in GUPCO wells recently has tights in casing like mentioned before.

Another case happens in Well X shown in Figure 9 light casing deformation encountered after decreasing Mwt. from 10.8 ppg to seawater at 8500'TVDss while bad cement job was across baba salts, applying equation on this condition found 7" LNR has problem when applying internal hydrostatic pressure 8.7 ppg while no problem should be encountered if 10.8 ppg used and that meet actual case.

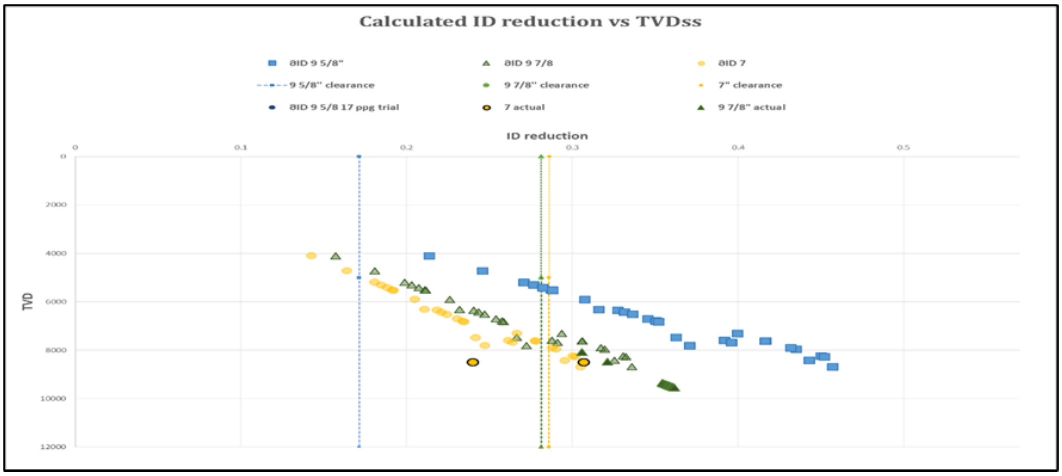

Fig.8. Applying new equation on data collected.

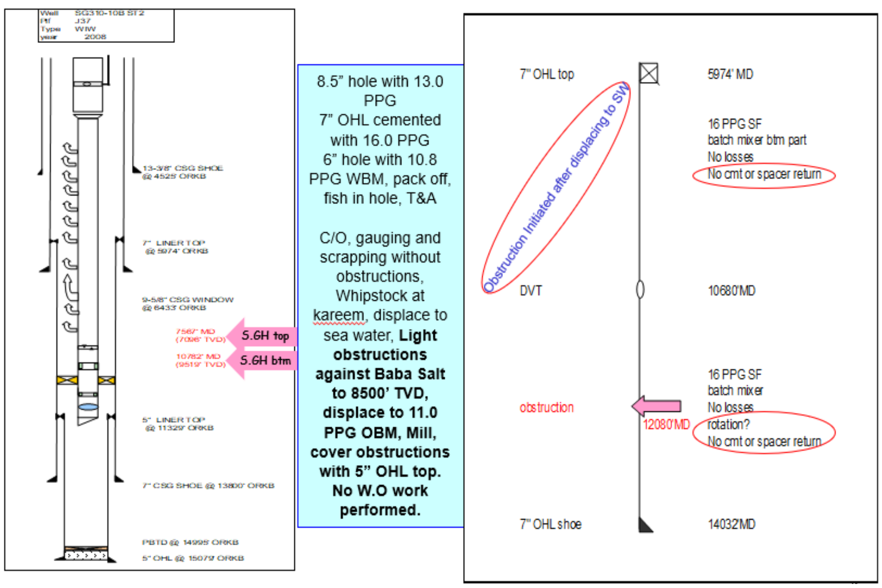

Fig.9. Case study: Well X casing obstruction after displacing to seawater.

5. Proposed casing design

5.1. Comparison with current design

The following Figure.10 shows current well designs using 9 5/8" #53.5 P110HC and covered with 7" concentric scab LNR as a double casing versus using 10 ¾" #104 Q125HC and 7 5/8" #55 PPF P110HC against salts that design take into consideration increasing wall thickness, higher ID/Drift clearance and higher collapse rating as a safety factor for replacing double casing with single one.

Proposed casing design (Figure 11) take into consideration to have higher ID/Drift clearance than current that will not affect future completions or well intervention.

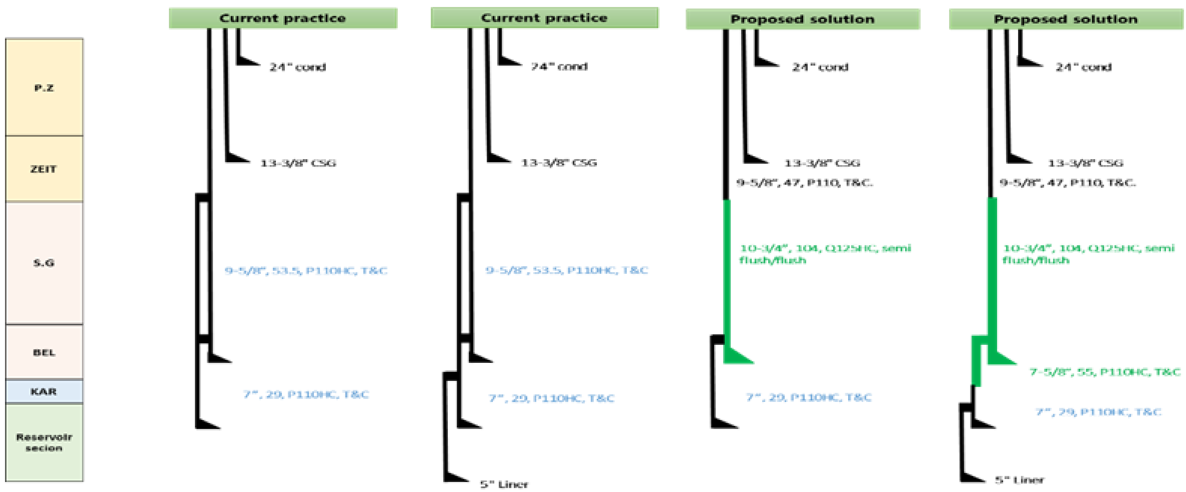

Fig.10. Comparison between current casing design and proposed casing design.

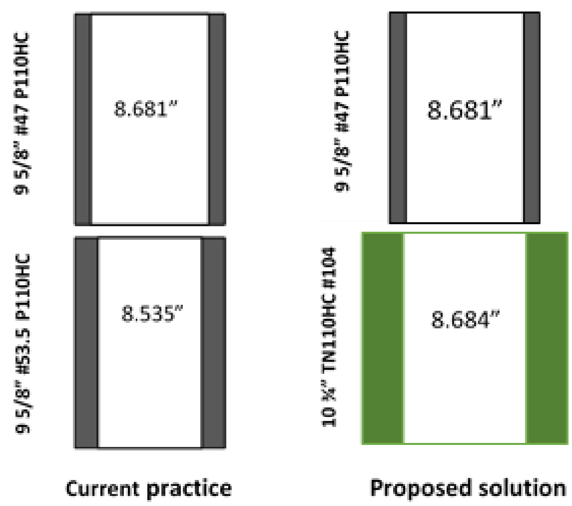

Fig.11. New casing design consider ID/Drift clearance.

5.2. Proposed casing specifications

Proposed casing design chosen based on collapse rating higher than 20,000 psi to be run against salt sections only like mentioned in previous sections as follows in Table 2:

1. Flush connection is preferable over semi flush connection as it gives more casing deformation clearance because it has no internal upset this means connection ID for flush connection is bigger than connection ID of semi flush.
2. Both inside diameter of 10-3/4″ and 7-5/8″ casing is in range of normal 9-5/8″ and 7″ Gupco used to run and so no special requirement for the liner hanger, wellbore clean out and completion accessories.
3. Special drift is not accepted as it decrease the tolerance for casing deformation only API drift is allowed.

Table 2. Proposed casing specifications against salt sections

Interval	OD (in)	Weight (ppf)	WT (in)	Grade	Connection	Drift	Casing ID (in)
from 5000 TVD or top S.G down to finish all salt section	10-3/4″	104-109	1″	Q125HC	Semi flush or flush	8.5″	8.684″
	7-5/8″	52.8-55.3	0.75″	P110HC	Semi flush or flush	6″	6.125″

5.3. Design verification

5.3.1. Verification using hydrostatic design

Using 2.5 psi/ft as external pressure gradient (Figure 12) based on calculated minimum external pressures form collected data, shows that using 10 ¾" #104 Q125HC uncemented with full evacuation considered will be effective against salt non-uniform loading. However, that way not take casing size or wall thickness into consideration.

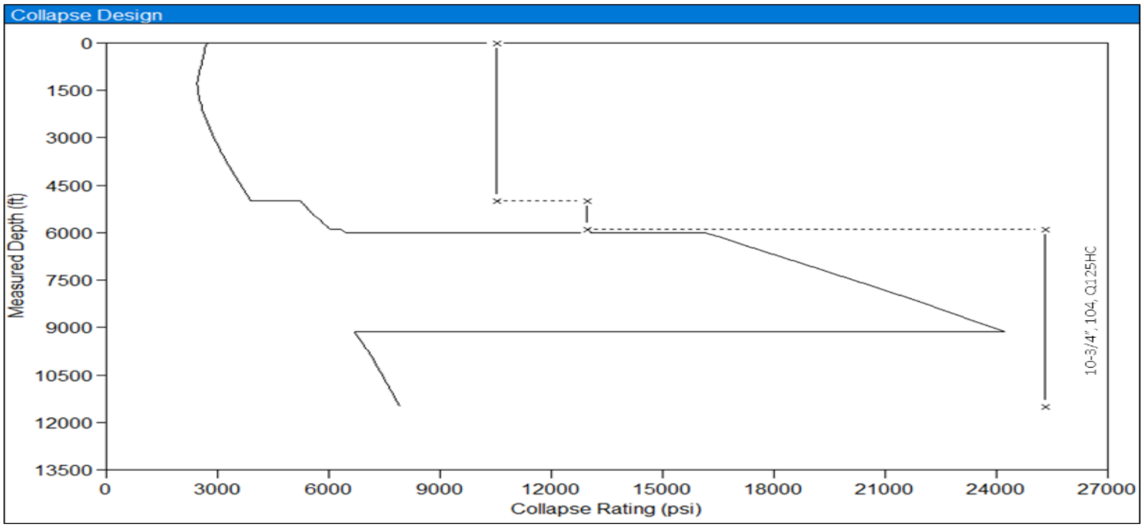

Fig.12. Verification proposed design using hydrostatic design.

5.3.2. Verification with Casing deformation equation (new concept)

Applying same conditions from offset data collected on proposed 10 ¾" #104 TN-125HC, and 7 5/8" #55 P110HC shows safe clearance from ID/Drift one, then applying gas gradient as internal hydrostatic pressure while production as a worst case uncemented full evacuated shows also good clearance that will be enough to be standalone against salt as shown in Figure.13.

5.4. Design benefits

5.4.1. Cost saving

As shown in Table 3. a cost comparison between current and proposed casing design, showing that average cost saving per well $760,000, that will be reflected directly in completion phase by reduction of scab liner cost and days.

5.4.2. Operation benefit

GUPCO recently has new challenges and opportunities to recover small opportunities in different fields. Using a single casing against salt give room for future wells opportunities by deepening sidetrack KOP up to 5000' and deepening 5" LNR injection point also up to 5000' TVD. That is direct solution for many of current marginal opportunities that can be accepted in future lead to higher profits and production.

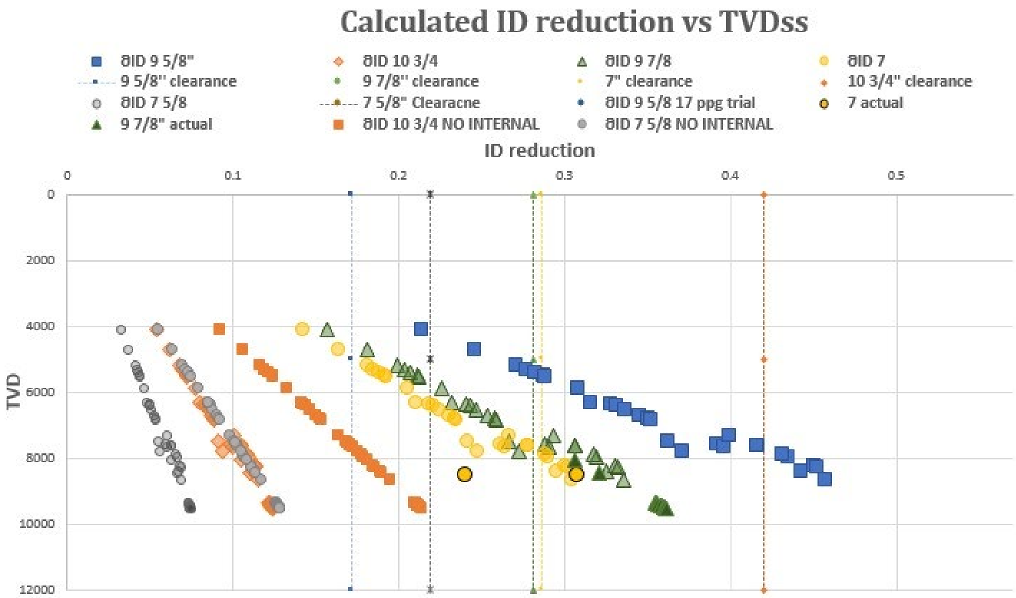

Figure 13. Verification on proposed casing design using modified equation.

Table 3. Cost comparison between current and proposed casing designs

9-5/8 + 7" scab liner		Proposed solution 9 5/8" X 10 ¾" single csg	
Item description	Item cost	Item description	Item cost
3000 ft. 9-5/8" casing joint	$370,000	5000 ft. 10-3/4" casing joint	$870,000
2000 ft. 9-7/8" casing joint	$177600		
Scab liner joint 5000 ft	$225,000		
Scab cement job.	$50,000		
Scab liner hanger and accessories	$50,000		
Scab liner rigid centralizers	$5,000		
Operation timing cost for polish mill, scab liner& C/O after scab	$750,000		
40% reduction in cement volume	$96,250		
Total	$1,627,600		
Average cost saving per well	$757,600		

Assumptions:

- 9-5/8, P110HC, 74$/ft.
- 7", 29, P110HC, 44$/ft.
- 10-3/4", Q125HC, 174$/ft.
- Spread rig rate $150k/day.

SIDKI field is an example for new casing design advantages as shown in Figure 14. SIDKI field located in S.GH salt doom with very long salt section, and very deep Belayim salt in BABA formation., the current well design using two scab liners 7″ scab LNR to cover 9 5/8″ against S.GH, and 5″ scab LNR to cover 7″ against deep BABA salts which gives a very shallow 5″ injection point that affects the productivity of field badly also close opportunities for sidetracks due to very shallow 7″ TOSL. Drilling team shows that the only solution to eliminate shallow 5″ TOSL is by using bigbore well design that will lead to more cost and days. Proposed casing design offers conventional well design with one single 10 ¾″ casing against S.GH and 7 5/8″ casing against BABA salts that will deepen 5″ TOL and eliminate shallow injection point problem, also give future room for sidetracks, and decrease cost by $8.5 M (saving bigbore and two scabs cost and days).

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July Field also considered a good example for benefits gained by using new casing design, the current design shown in Figure.15 showing that main design setting 9 5/8″ casing against S.Gharib and Belayim salt formations at (8700′ TVDss), then cont. drilling to section TD and run 7″ LNR followed by extending 7″ scab LNR to cover all salt formations up to 5,000 TVD, this design is same for July field. Using new casing 10 ¾″ 104 ppf, Q-125HC, instead of 9 5/8″ 53.5 ppf, P110HC will save cost and time of using 7″ scab liner, gives very good room for future sidetrack.

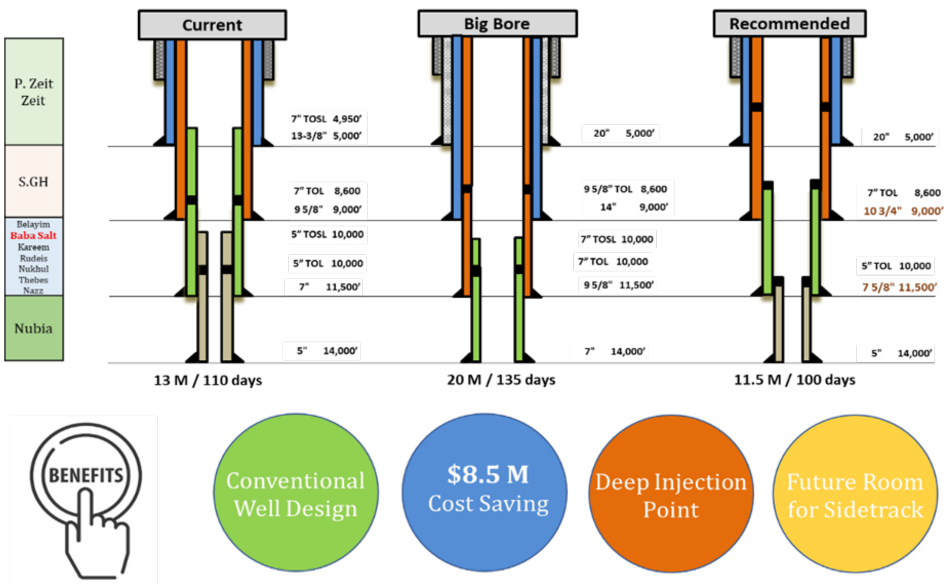

Fig.14. Verification on proposed casing design using modified equation.

Using new casing 10 ¾″ 104 ppf, Q-125HC, instead of 9 5/8″ 53.5 ppf, P110HC will save cost and time of using 7″ scab liner, gives very good room for future sidetrack.

Formation	TVDss (ft)	MD (ft)
ZEIT	1690	1840
S.GH	5897	7799
FEIRAN	8136	11434
KAREEM	8767	12459
Asl	9128	13045
Hawara	9602	13814
Hawara S.ST	9673	13929

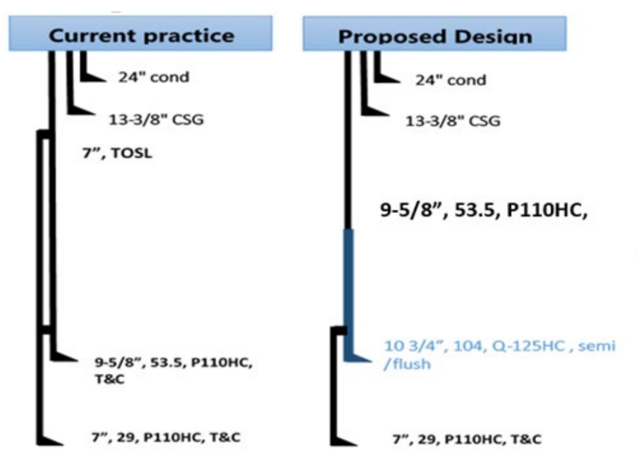

Fig. 15. JULY field example for operational benefits using new design.

6. Beyond the limit

The previous sections shows that new casing that will be used in new design has a good safety factor to be used as single casing instead of concentric double casing against salts. However, Time factor is not considered, how long standalone casing could withstand the salt non-uniform loading, difference of salt loading from field to another and how salt interact with casing. The main reason for that due to limited data of single casing against salt is using double casing to support it as fast as we can to avoid tights inside casing.

The next section will adopt a way to improve casing design, analysis to decrease safety factor based on severity by collecting new in-situ data for new single standalone casing using ultrasonic image logging corrosion mode, from data collected at different periods of well life we should have a model using finite element analysis (FEA) to simulate salt loading and calculating missing creep rate.

6.1. Creep rate calculation

As per mention before in data collection section, USIT logs data collected for 9 5/8" 53.5" standalone opposite to salts, data analysis for ovality ratio considering time to take log so we have now a rate "creep rate" the next chart shows creep rate values versus TVD, from which we can found that we have low creep rate trends for TVD values less than 6500' and trend increase as we go deeper.

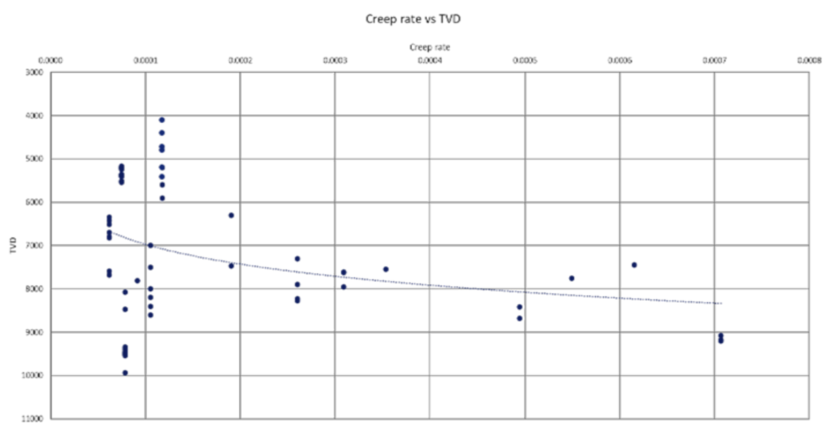

Fig. 16. Calculated creep rates from collected data.

Despite the lack of data, area to improve rise from that chart if we got more data points, we should consider more accurate safety factor that can lead us to use less grade or size like 9 7/8" or 10" to 6500 as example. The next figure 17 shows steps to get new database.

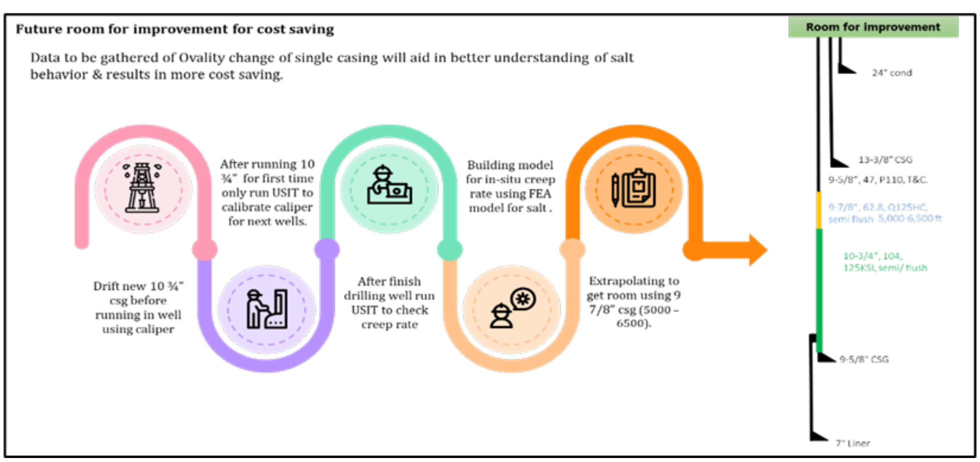

Fig.17. Steps for future design improvement.

7. Conclusions

Salt deformation due to non-uniform salt movement has higher impact higher than normal overburden gradients 1 psi/ft on intermediate casing specially 9 5/8", 53.5 ppf, P 110 HC due to small clearance between csg ID and drift OD for next section drilled.

According to data collected from different fields salt non-uniform loads should be estimated at high gradients up to 2 – 2.5 psi/ft., which means higher collapse rating for depths higher than 5000 ft-TVDss could replace using of GUPCO standard concentric double casing cemented.

According to new developed equation radial deformation due to non-uniform loads due to salt movement depend on diameter and thickness of casing opposite to salt formation, that is reason why 7" LNR withstand higher radial deformation than 9 5/8" csg, also equation used to confirm using new casing design for future wells.

Initially replace 9-5/8", 53.5 ppf , P110HC, T&C casing string in GUPCO casing design with 10-3/4", 104, Q125HC (24 Kpsi), semi flush or flush connection against salt bodies below 5000 ft-TVD or from Top of S.G, which comes first. Also replace 7", 29, P110HC, T&C casing with 7-5/8", 55, P110HC (20 Kpsi), semi flush connection against the salt section below 5000 ft-TVD or from Top of S.G, which comes first.

Due to ovality data collected there is potential to have lower casing grades for the interval from top of S.G formation to 6,000 ft. so that FEA and mechanical simulation analysis for ovality data could be done to optimize the proposed casing design for cost saving and improve the model

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