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A Field Trial of Using High-Density Polyethylene for Internal Lining of Production Tubing in Highly Deviated Wells Produced by Sucker-Rod Pumps

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Abstract

High density polyethylene liners are commonly used in shipping pipelines, vertical naturally producing wells and injection wells. Mainly, HDPE liners are used to protect these tubulars from corrosion, to reduce pressure drop issues, and to increase the fluid capacity. Thus, tubulars' lifetime are extended, and costs related to corrosion control, such as chemical injection, cathodic protection, or coatings are diminished. In General Petroleum Company, for economic purposes, artificial islands were constructed and wells were drilled with high deviation angles to cover wider drainage area. Initially, wells were producing naturally, then most of them were recompleted to produce artificially via sucker-rod pumping systems to overcome limited production capacities and reservoir depletion.

Due to high corrosivity of produced fluids accompanied with high abrasion rates between sucker-rods and tubing, many failures occur, and some wells are daily intervened to fix their problems to put them on production. It became a headache for the owners as many attempts to reduce the frequency of well interventions ended up with no success. HDPE liners were offered to mitigate mechanical wear and prevent corrosion.

This paper will present this case study in detail by showing the failures associated with using sucker rod pumps in highly deviated wells, how HDPE may be a good solution to solve these failures, and a detailed analysis for the economic benefits and improvements of tubulars service lifetime..

***Keywords**: HDPE lining; Sucker-rod pumps; Deviated wells; Abrasion; Financial evaluation.*

1. Introduction

Gharib Field is an old mature oil field. Its wells were drilled with high deviation angles on artificial islands to cover a wider drainage area under the sea level. Initially, there were no problems in production and limited well interventions because they were producing naturally. Because of reservoir maturation and increased water production, the production rate of these wells decreased dramatically, and wells were ceased. Therefore, they have been recompleted to produce artificially via sucker rod pumps to overcome the pressure drop and maintain their production.

Simultaneously, failures started to appear and the frequency of well interventions increased drastically. Failures occurred in the tubing, the rod string, and in the pump itself. It was noticed that most of the failures happened to either the tubing or the rod string were localized in certain points and even after replacements, they occur frequently in these points. These failures were analyzed, and the root cause is the severe dogleg angle exceeding 5^o/100 ft. at these points.

Obviously, wells are subject to rapid pump off resulting in rods compression. Failures occurred due to the mechanical wear resulting from the direct contact between tubing and rod string in points of severe dogleg angles. The problems are escalated by the production of large amounts of water and large volume fractions of corrosive gases (carbon dioxide and hydrogen sulfide). Despite the continuous injection of corrosion inhibitors, their effect is not as desired due to being injected from the wellhead and the absence of proper mixing with the produced fluids.

Frequent production interruptions affect the well's economics directly and indirectly. The direct loss is depicted as the loss of oil yield until the well is repaired, and the production is restarted. The indirect loss is visualized in the form of paying well intervention bills as wages for the workers and the rent fees of the pulling unit/workover rigs. In addition, it includes the bill of corrosion inhibitor injection with no success of preventing or, at least, retarding corrosion rates. The profitability from oil production of these wells cannot support these costs.

Therefore, it became necessary to search for a vital solution to prevent the occurrence of these failures. One of the solutions was lowering the number of strokes per minute and extending the stroke length to maintain the required production rate with less mechanical wear. The mechanical wear was slowing down, but it was still there. It increased the mean time between failures (MTBF) a little bit. Unfortunately, the corrosion rate accelerated the failure. Thus, it did not meet the common practices.

HDPE liners were offered as a radical solution for this complex situation. Its ductility and resilience intensely reduce the mechanical wear resulting from the direct contact between tubing and rod string. In addition, it forms a corrosion barrier by isolating the steel tubing from direct contact with produced corrosive fluids [1].

2. HDPE and its properties

Plastics are polymers that are made of a chain of repeated molecules called monomer. They are divided into two types: thermoset and thermoplastic. Thermoset is a material that strengthens when heated but cannot be remolded or heated after the initial forming. Thermoplastics can be reheated, remolded, and cooled as necessary without causing any chemical changes. Polyethylene is a type of thermoplastics that is made of ethylene monomers[2-3].

High density polyethylene (HDPE) is less branched than low density polyethylene (LDPE) Less branching provides stronger intermolecular forces resulting in higher strength to density ratio (≈ 940 kg/m^3) compared to LDPE (≈ 920 kg/m^3). The range of temperature that HDPE can withstand is between -28 & 71 oC and the maximum rated pressure is 2000 psi. Also, HDPE is a chemical inert and offers great chemical resistance against a lot of salts, corrosive fluids, and organic solvents. Because of its smooth surface, it prevents organic deposition and scale buildup. HDPE ductility and impact resistance give an advantage to be used in abrasive environments. Because of these properties, HDPE liners are widely used in shipping pipelines, water and gas injection wells, and water disposal wells [2-3].

3. HDPE lining process [3]

The offered lining process for tubing is a little bit different than the slip-lining lining process for shipping pipelines. It follows the following procedures:

1- Tubing preparations:
- a- Clean and inspect the pipes as per API RP 5A5.
- b- Clean the pipe body and thread.
- c- Fill out the tubing preparation report.

2- Thread examination:
- a- Examine visually the pin and coupling end threads and ensure that they are free of galling, pitting, sharpened threads, or other abnormalities.
- b- Verify thread stand-off for pin and coupling threads by using standard API ring and plug gauges~~.~~
- c- Complete thread examination report.

3- HDPE liner preparations:
- a- Visually examine HDPE liners to ensure that they are free from any obvious defects; such as collapses, holes, or debris inside of the liner.
- b- Prepare the flange formation machine which includes a heating element and a hydraulic mold.
- c- Insert one end of the liner into the machine. The heating element will soften the liner's end and the flange shape will be formed by the hydraulic mold.

d- Remove the liner from the machine and insert it into the pipe carefully to set the formed flange to coupling end on a certain depth as per the supplier's instructions.
e- Complete the non-conformance report of rejected liners.

4- Special blend preparation:

It is a special cementing material that glues the HDPE liner to the pipe steel. It is blended according to the supplier's instructions.

5- Blend injection:

a- Prepare the injection pump, hoses, and other accessories.
b- To the pipe pin end, fix a special applicator which seals the pipe/liner annulus and has a valve that allows controlling the blend injection process.
c- Connect the hose to the valve and start injecting the blend. As per the supplier's instructions, at certain back pressure observed visually on the pump's pressure gauge, injection is stopped. This pressure indicates the completion of injection process.
d- Ensure that the flange depth to coupling end does not change.
e- Extract the blend residues from the coupling.

6- Pin end handling:

a- Extract/ clean the applicators.
b- Compact the blend using a flat scraper tool.
c- Brush the pin thread.
d- Leave the pipe till blend solidification.
e- By using an approved cutting tool, trim the liner's excess length.
f- By using the flange formation machine, the pin end liner is heated and molded.

7- Holiday testing:

It is a non-destructive test method applied on protective coatings to detect unacceptable discontinuities by alarming the flow of an electric current across holes or voids. Finally, each pipe is tested by the holiday test to check that the HDPE liner is set properly and there are no bare parts of steel.

4. Field trial considerations

Two wells (GH-229 & GH-237) were subject to trial. They were selected for a one-year trial, and the reasons for considering them as good candidates for HDPE lining were:

1- The high well intervention frequency. The average MTBF wasn't more than two weeks.
2- The wells' deviation with severe dogleg angles. Deviation surveys for both wells are tabulated in Appendix.
3- The high production of corrosive gases; H_2S & CO_2 with volume fractions of 1.8% and 9%, respectively. HDPE shows a satisfactory behavior against both gases and their acids.
4- The downhole temperatures of GH-229 (65°C) and GH-237 (68°C). These are less than the maximum rated temperature of HDPE (71°C).
5- The marginal production with high water cut. GH-229 is producing about 161 BFPD & 72% WC, while GH-237 is producing about 113 BFPD & 70% WC.
6- The high daily corrosion inhibitor dosage.

The well data for GH-229 & GH-237 before the trial was as shown in Table 1. HDPE lining reduces the ID of tubing as mentioned in Table 2. The available pump sizes are 1.75″ & 2.25″; therefore, both wells were completed with 3.5″ tubing, and insertable pumps of size 1.75″ (OD: 2.25″) to be inserted through the liner (ID: ± 2.61″). Thus, the pumping parameters (SPM & S.L.) of GH-229 were modified to meet the desired rate of 2.25″ pump size. The new pumping parameters required using 1″ rod string (coupling OD: 2.1875″) instead of 0.875″ (coupling OD: 1.8125″).

The main condition for the success of this trial was to keep the wells on production with no failures related to the lined tubing that needed to be pulled from the hole. This condition is valid for one year and each well will be evaluated separately.

Table 1. GH-229 & GH-237 well data

Well Data	GH-229	GH-237
Pump setting depth, ft.	1960	2239
Perforation depth, ft.	2240	2467
Maximum well deviation, °	59	46
Maximum dogleg angle, °/100 ft.	8.8	5.6
Tubing size, in.	2.875	3.5
DHP type	Tubing	Insertable
DHP size, in.	2.25	1.75
DHP od, in.	2.75	2.25
Sucker rod diameter, in.	0.875	0.875
Full size coupling diameter, in.	1.8125	1.8125

Table 2. Specifications of liners for different EUE tubing sizes

Pipe size, in.	Pipe nominal weight, lb./ft.	Liner ID, in.
2-7/8	6.5	± 2.09
3-1/2	9.3	± 2.61
4-1/2	12.75	± 3.52

Table 3. Tubing properties (subject to trial)

OD, in.	Weight, lb./ft.	Grade	ID, in.	ID after lining, in.	Length, ft.	Thread Type	Condition
3.5	9.3	L80	2.992	±2.61	R2 (27-30)	EUE	Condition B

5. Field installation procedures

Pipes were run in the well as follows:

1- The following string was run first before running the lined pipes; perforated joint – unlined tubing joint – seating nipple.

2- Between two pin ends inside a coupling, there is a clearance that should be filled with a corrosion barrier ring (CBR) to completely isolate the steel from the attack of corrosive fluids. Figure 1.-A illustrates a schematic diagram for CBR and how it isolates the connection steel from direct contact with corrosive fluids. Figure1.-B represents a realistic picture for CBR.

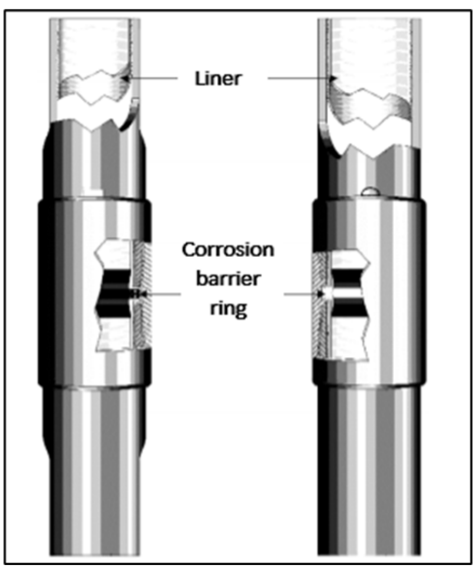

Figure 1. A) An illustrative diagram showing the CBR between two lined-pipe-pin ends [2], B) A Realistic picture of CBR

3- CBR has different lengths; 0.25", 0.5" & 0.75". By measuring the remaining length of the coupling's thread and the other pipe's pin thread length, the length of CBR is determined.

It should not be smaller than the clearance to avoid poor isolation and not larger than it to avoid CBR collapse when connecting pipes [4].

Note: After each connection, a drift test was done to ensure that both the ID of the liner was free from any obstructions and the CBR didn't collapse using a bar diameter of 2.375". (The usual used drift size was 2.44", but because of rejection 5 pipes out of 20 rejected due to no drift, supplier recommends reducing the drift size to be 2.375" (still larger than pump's OD).)

4- The standing valve was thrown, and three hydrostatic pressure tests of 500 psi were accomplished to ensure that there was no leakage happened.

5- Pump was set, rods were run, and surface connections were assembled. Finally, the well started production, and the corrosion inhibitor injection was stopped for the whole trial duration.

6. Results and discussion

For GH-229:

Table 4 shows a comparison between the failures before and after the lining. Before lining, the well was producing for an average of 376 hrs./m. with a percentage of 52.5%. Furthermore, the monthly average active servicing time in which pulling unit/workover rig repairs the well for tubing/rod string issues was 23 hrs./m. After lining, the average monthly running time increased to 711 hrs./m. with a percentage of 98.7%, and the active servicing time vanished totally.

Table 4. A comparison between the failures before and after HDPE lining for GH-229

Before lining					After lining				
2019	Shut-in time, hr.*	Running time, hr.	Active servicing time, hr.**	Reason of shut-in	2020	Shut-in time, hr.*	Running time, hr.	Active servicing time, hr.**	Comments
Jan.	289	455			Jan.	336	408	24	Trial start date 15/1/2020
Feb.	672	0			Feb.	48	648	2	Changing bridle
Mar.	744	0	108	Tubing hole	Mar.	0	744		
Apr.	501	219	105	Pump failure	Apr.	48	672	12	Pump gas lock
May	116	628	12	Broken rod	May	0	744		
Jun.	257	463			Jun.	0	720		
Jul.	744	0	36	Damaged coupling	Jul.	0	744		
Aug.	106	638	10	Pump gas lock	Aug.	13	731	5	Leakage in P.L.
Sep.	0	720			Sep.	0	720		
Oct.	0	744			Oct.	0	744		
Nov.	525	195	96	Tubing hole	Nov.	0	720		
Dec.	192	522	24	Damaged coupling	Dec.	0	744		
Avg./m.	342	378	23***		Avg./m.	9	711	0***	No shut-in hrs. due to lining failure
%	47.5%	52.5%			%	1.3%	98.7%		

* The long period of shut-in refers to the waiting time till well intervention plus the servicing time.
** Active servicing time represents the pulling unit/workover rig renting time.
*** The average active servicing time is calculated only for tubing and rod string failures (underlined).

Table 5 presents the feasibility of using HDPE lining instead of bare tubing associated with corrosion inhibition in GH-229. First of all, it reduces the yearly frequency of well interventions due to tubing/rod string failures from 5 times to none reducing the yearly servicing cost which is calculated as follows:

$$Yearly\ servicing\ cost = avg.active\ servicing\ time/month * 12 * servicing\ cost/hr. \qquad (1)$$

Before lining, the yearly servicing cost for tubing/rod string failure was 55,200 $, while, after lining, it became zero. Furthermore, yearly corrosion inhibition cost is calculated as follows:

$$Yearly\ inhibtion\ cost = avg.running\ time/month * 12 * Corrosion\ inhibition\ cost/hr. \qquad (2)$$

Lining eliminates the cost of yearly corrosion inhibition costs which were 2,930$. On the other hand, the only added costs were the cost of lined tubing installation and the cost of HDPE lining itself. It is calculated as follows:

$$Total\ lining\ cost = (No.of\ joints * liner\ cost\ per\ joint) + (installation\ time * Servicing\ cost/hr.) \qquad (3)$$

The total lining cost is 18,200 $. Therefore, lining reduces the expenditure to keep the well on production by about 70% (from 58,130 to 18,200$).

Table 5. Feasibility analysis for using HDPE lining in GH-229

		Before Lining	After Lining
Costs	Frequency of well interventions due to tubing/rod string failures a year	5	0
	Average active servicing time/m., hrs./m.	23	0
	Yearly servicing cost for tubing and rod string failures, $ *	55,200	0
	Average productive time, hrs./m.	376	711
	Yearly corrosion inhibition cost, $ **	2,930	0
	Number of lined tubing pipes	67	
	Total lining cost including installation, $ ***	0	18,200
	Total costs, $	58,130	18,200
Revenues	Average productive time, hrs./m.	376	711
	Oil production rate, Bbl./hr.	2	
	Yearly production, Bbl./yr.	9,030	17,070
	Yearly revenue, 1000 $ ****	451.5	853.5
Benefits of HDPE lining	Percentage of reduction in expenditure	68.7%	
	Percentage of increase in revenues	89%	
	Benefit, 1000 $ =(Total revenues after lining – Total costs after lining) - *(Total revenues before lining – Total costs before lining)* ***** (4)	441.93	

* Servicing cost is estimated considering multiple factors to be 200 $/hr
** Corrosion inhibition cost/hr. including inhibitor dose and pump rent is 0.65$/hr
*** Liner cost per joint is 200 $
**** Oil price is set to be 50 $/Bbl
***** Replacement costs for damaged tubing or rod string are neglected

Additionally, the revenues should be increased significantly because of the increased well-running time resulting in increased sales oil volume. Revenue is calculated as follows:

$$Yearly\ revenue = avg.production\ time/month * oil\ production\ rate * 12 * oil\ price \qquad (5)$$

The revenue before the lining from GH-229 was 451,500$, and after the lining, it became 853,500$. It means that revenues have increased by about 90%. Thus, the cumulative yearly benefit from utilizing HDPE lined tubing instead of bare tubing associated with corrosion inhibition is 441,930$ and the trial was successful according to its conditions.

For GH-237:

Before the lining, the well was suffering nightmarishly from tubing holes and rod string damages, Table 6. The well's average production time was 333 hrs./m. with a percentage of 46.3%. Afterward, the production time increased to become 610 hrs./m. with a percentage of about 85%. The trial was running smoothly till July-2020; however, a major failure occurred in the lined tubing. Thus, the trial was only evaluated until second of July-2020.

Table 6. A comparison between the failures before and after HDPE lining for GH-237

Before lining					After lining				
2019	Shut-in time, hr.*	Running time, hr.	Active Servicing time, hr.**	Reason of shut-in	2020	Shut-in time, hr.*	Running time, hr.	Active Servicing time, hr.**	Comments
Jan.	196	548	12	Pump gas lock	Jan.	648	96	24	Trial start date 28/1/2020
Feb.	552	120	116	Tubing hole	Feb.	336	360	168	Multiple pump failures
Mar.	696	48	98	Tubing hole	Mar.	96	624	24 & 30	Broken rod & pump failure, respectively
Apr.	457	263	24	Damaged rod coupling	Apr.	48	672	24	Change stuffing box & pump gas lock
May	218	526	56	Broken rod	May	0	744		
Jun.	271	449	18	Pump gas lock	Jun.	48	672	12	Damaged rod coupling
Jul.	380	364	24	Damaged rod coupling & broken rod	Jul.	720	24	72	Lined tubing failure on 2/7/2020
Aug.	324	420		Tubing hole	Avg./m.	110	610	21	****
Sep.	720	0			%	15.3%	84.7%		
Oct.	360	384	137		Aug.	744	0		A decision was taken to stop the trial in this well
Nov.	4	716			Sep.	720	0		
Dec.	529	215	41	Broken rod	Oct.	744	0		
Avg./m.	387	333	41***		Nov.	720	0		
%	53.7%	46.3%			Dec.	744	0		

* The long period of shut-in refers to the waiting time till well intervention plus the servicing time.
** Active servicing time represents the pulling unit/workover rig renting time.
*** The average active servicing time is calculated only for tubing and rod string failures (underlined).
**** The average times were calculated for five months and a week.

6.1. Trial failure in GH-237

When the pump was retrieved to be changed/repaired in Feb-2020, some lining part was found stuck in the pump; Figure 2. By analyzing this part, it was assumed that this part was cut from a deep joint beside the seating nipple and failure occurred due to multiple attempts to set the pump in its nipple. According to trial conditions, it was decided to continue the trial till a major failure in the lined tubing that needed to be pulled out. The pump was retrieved again three times till July-2020, and in each time, there was a part stuck to the pump.

In July-2020, the pump was retrieved with larger overpulls compared to previous retrievals to be changed by a new one. When it was run in the well, it was not be able to be seated in its seating nipple because of an obstruction resulting in the necessity to pull out the lined tubing. When the lined tubing string was retrieved, it is found that seven lined joints were severely damaged, and the cuts were accumulated on the seating nipple forming the obstruction. The damaged joints are 23, 30, 35, 59, 60, 64 & 66.

Obviously, the upper three joints with depths of 620, 810 & 945 feet were damaged because of high tubing/rod string wear resulting from the dogleg angle, as illustrated in Appendix B. The lower four joints were most probably damaged because of attempts to set the pump in its seating nipple. The possible analysis of the difficulty to retrieve the pump was either because of the accumulation of lining cuts above the pump, or barely because of swelling in HDPE lining. It is decided to stop the lining trial in this well because it fails to fulfil its conditions.

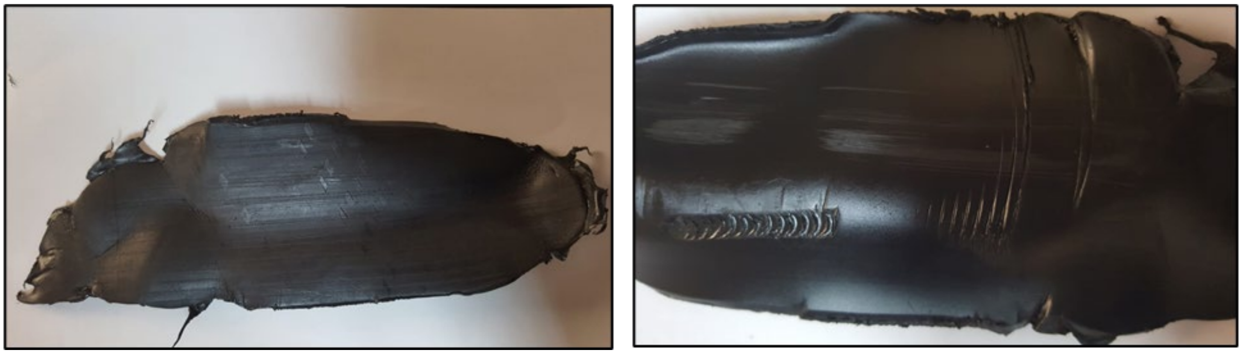

Figure 2. Pictures of a one of the found part that were found stuck in the pump when it is retrieved in Feb-2020

7. Economic analysis

Table 7 summarizes the feasibility of lining the tubing string of GH-237. Given the same circumstances, the performance of the well during the period from starting the trial to its failure was generalized to include the whole year.

Table 7. Feasibility analysis for using HDPE lining in GH-237 up till the Jun-2020. (Note: For reasonable analysis, trial and failure circumstances ware generalized to include the whole year)

		Before lining	After lining
Costs	Frequency of well interventions due to tubing/rod string failures a year	7	7
	Average active servicing time/m., hrs./m.	41	21
	Yearly servicing cost for tubing and rod string failures, $ *	98,400	50,400
	Average productive time, hrs./m.	387	610
	Yearly corrosion inhibition cost, $ **	3,020	0
	Number of lined tubing pipes	71	
	Total lining cost including installation, $ ***	0	19,000
	Replaced lining joints cost, $	0	2,800
	Total costs, $	101,420	72,200
Revenues	Average productive time, hrs./m.	387	610
	Oil production rate, Bbl./hr.	1.4	
	Yearly production, Bbl./yr.	6,500	10,250
	Yearly revenue, 1000 $ ****	325	512.5
Benefits of HDPE lin-ing	Percentage of reduction in expenditure	28.8%	
	Percentage of increase in revenues	57.7%	
	Benefit, 1000 $ =(Total revenues after lining – Total costs after lining) - (Total revenues before lining – Total costs before lining) *****	216.7	

* Servicing cost is estimated considering multiple factors to be 200 $/hr.
** Corrosion inhibition cost/hr. including inhibitor dose and pump rent is 0.65$/hr.
*** Liner cost per joint is 200 $.
**** Oil price is set to be 50 $/Bbl.
***** Replacement costs for damaged tubing or rod string are neglected

Regarding the well intervention frequency, there was no perceptible change, but it was obvious that the average active servicing time was decreased significantly from 41 to 21 hrs/m. This reduction was because of the absence of tubing failures that require a long period to be repaired. Lined-tubing replacements require 72 hrs. to retrieve the string, replace the damaged joints and do full string inspection to be re-installed.

Previously, the yearly expenditure was 101,420$ including: the servicing cost of 98,400 $ and the corrosion inhibition cost of 3,020$. Later, it decreased by about 30% to be 72,200$ including: the servicing cost of 50,400$, the lining initial installation cost of 19,000$ and the replaced joints cost of 2800$ (Assuming flat rate of damaged joints per failure to be 7 Jts.).

On the other hand, the revenues were increased approximately by 60%. This increase was because of increased well's running time to be 610 instead of 387 hrs./m. Hence, the profit was 216,700$ from the lining trial of GH-237 tubing string. By implication, regardless of the failure, the trial results were acceptable.

8. Conclusions

In addition to the capability of HDPE lining to prevent corrosion by isolating the steel from contact to corrosive fluids, its ductility and resilience can be a proper solution in deviated wells operating with sucker rod pumps. It absorbs the impact of tubing/rod string contact, and this significantly reduced the mechanical wear in deviated wells. Thus, it extended the well's running time, and decreased the frequency of well interventions as presented in GH-229.

Up till the failure, the trial results in GH-237 were acceptable to large extent. The trial was interrupted due to the failure that occurred in seven lined tubing joints. Overall, the idea was accepted, but the trial did not fulfil the agreed conditions.

9. Recommendations

The trial of internal HDPE lining to be used in downhole tubing was the first in GPC and in Egypt. It cannot be judged that it is fruitful by its success in one well. It should be examined in more wells. The possible causes of the trial failure in GH-237 should be re-evaluated and discussed; such as bad blending or bad blend injection, lining swelling because of gas presence, bad handling, sensitivity to critical temperatures, or other causes. For further precautions, an oil sample from each well should be sent to evaluate the compatibility test and the effect of this sample on HDPE behavior.

Appendix. Deviation Survey for GH-229 & GH-237

Table 8. GH-229 deviation survey

St. No.	MD (ft.)	Dev. Deg.	Calculated Dogleg
1	320	11.5	
2	446	18.5	5.56
3	603	23.5	3.18
4	695	27	3.80
5	789	30	3.19
6	914	36.5	5.20
7	1060	43.5	4.79
8	1135	46	3.33
9	1229	48.5	2.66
10	1253	48.5	0.00
11	1457	48.5	0.00
12	1650	49	0.26
13	1727	49	0.00
14	1997	50	0.37
15	2279	50	0.00

Table 9. GH-237 deviation survey

St. No.	MD (ft.)	Dev. Deg.	Calculated Dogleg
1	310	9	0
2	520	19	4.78
3	700	29	5.49
4	880	31	5.02
5	995	34	3.64
6	1270	35	1.3
7	2000	41	0.83
8	2380	38	0.84

Nomenclature

Bbl.	*Barrel*	*lb./ft.*	*Pound mass per foot*
BFPD	*Barrel fluid per day*	*LDPE*	*Low density polyethylene*
CBR	*Corrosion barrier ring*	*m.*	*Month*
GPC	*General Petroleum Company*	*MTBF*	*Mean time between failure*
HDPE	*High density polyethylene*	*º/ft.*	*Degree per foot*
ID	*Inner diameter*	*QC/QA*	*Quality control & quality assurance*
OD	*Outer diameter*	*S.L.*	*Stroke length*
in.	*Inch*	*SPM*	*Stroke per minute*
kg/m^3	*Kilogram per cubic meter*	*WC*	*Water cut*

Acknowledgements

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