

Case Study

Implementation of Stimulation treatment for gas-lift well in Sirt Basin, Libya

Emad Ibrahim Mohamed Fandi¹

(Senior Technical Professional –Frac/Acid with Halliburton Company in Libya)

Badees Khalifa Gazal²

(Senior Reservoir Engineer – Subsurface with Hess Libya Exploration Limited)

Abduarazak El- Amori³

(Production Supervisor – Amal Field with Harouge Oil Operations)

ABSTRACT

Many sources of formation damage exists which normally contribute to a reduction in well productivity by introducing an extra positive skin near the wellbore. The main objective of matrix stimulation treatment is to remove this damage.

Such treatment was a new approach in Amal formation contained within Sirt basin. The challenge faced was the need to inject Break-Down Acid Job (BDAJ) technique without inducing fractures in the formation (safety margin bottom-hole pressure value should be not be exceeded), meanwhile, the formation was depleted and applying high injection rate was essential to ensure that the acid reaches the targeted zone.

This paper details a combination of techniques, implemented in Sirt basin, which have proven to enhance the overall operations' economics and well deliverability. Furthermore, the paper describes a novel approach for Gas Lift Analysis.

A proper design was achieved following the proposed techniques resulting in a successful stimulation treatment. Certain measures were required to avoid causing any damage and to deal with unexpected events.

The formation responded positively to the acid treatment. A significant increase in flow rate was observed indicating a successful treatment and that the well restored its natural undamaged inflow performance successfully.

In this study a detailed economic impact was done to confidently prove the profitability of the treatment over the production life of the well. The results obtained from this case study suggest that several wells producing from Amal formation can benefit from the proposed new techniques.

Keywords: Stimulation treatment; Gas Lift; Sirt Basin; Libya; Economic Impacts; NPV.

1. INTRODUCTION

Sirt Basin contains about 89% of all the known hydrocarbon accumulations in Libya. Amal formation, a new formation in the eastern Sirt basin, has been selected for productivity stimulation treatment. The candidate well was selected based on actual field performance analysis. The well performance indicated a steep reduction in deliverability when compared with the offset wells. Several

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

factors contributed to this weak performance, e.g. the well was drilled almost in 1975 and avoidance of issues with the drilling and completion fluids used at that time, found in the drilling and completion reports. In addition, core analysis and production history combined indicate the possibility of sand migration.

This paper emphasizes the methodology followed to successfully optimise the first implementation of stimulation treatment in Amal formation. The aim of the study was to enhance well deliverability, improve Gas Lift Analysis and maximise the economics. The targeted formation responded positively to the suggested treatment. A significant increase in flow rate was achieved indicating that Hydraulic acid (HCl) reduced formation damage and drilling fluids as planned.

In this study a detailed economic impact was done to confidently prove the profitability of the treatment over the production life of the well. The results obtained from this case study suggest that several wells producing from Amal formation can benefit from the proposed new techniques.

2. LITERATURE REVIEW

There are many sources of formation damage which may cause a reduction in the permeability of the near wellbore area (see David, 2014).

Based on semi-steady state, radial flow equation $Q = \frac{Kh(P_e - P_{wf})}{\mu B_o (L \ln \frac{r_e}{r_w} + S)}$, there are two possible options to enhance the well inflow performance: 1) increasing the permeability-height factor, or 2) decreasing the skin factor. Matrix stimulation mainly improves the well inflow performance by removing the formation damage and increasing the effective wellbore radius. In other words, this treatment aims to remove the excess flowing pressure drop created by presence of formation damage around the wellbore. The additional pressure drop is represented by Hawkins formula as a skin factor: $S_d = \left[\frac{K_o}{K_{do}} \right] \ln \left(\frac{r_d}{r_w} \right)$.

Amal formation, the targeted formation for acidizing stimulation, is a sandstone reservoir. The acid treatment should primarily increase the effective wellbore radius. This goal can be achieved by dissolving the matrix in the immediate surrounding area of the borehole, and by re-opening the existing perforations. In addition, the removal of the formation damage resulting from drilling and/or completion fluids from the formation face and the invaded zone is expected to contribute to an improved well performance after the treatment.

A proper candidate selection is one of the key pillars of this study. The lessons learnt shall be applied on the remaining producers from Amal formation. The aim of this pilot test is to avoid the most common mistakes in the design of the operational aspects such as compatibility test, and to test the efficiency of acid diversion approach to ensure that the targeted producing zones were selectively acidized. Such additives act as a polymer forcing the acid to flow in the hydrocarbon zones by changing the effective permeability; consequently the acid will be diverted to the required zones. The strategy followed was to select a well that is capable of a greater hydrocarbon production rate, analysis of the skin sources and selection of the optimum type of stimulation fluid to remove this skin and a proper design of the operation (see David, 2014). Furthermore, the economic analysis of the operation and the expected production improvement should ensure that the extra hydrocarbon production will be greater than the cost of the treatment.

3. SIRT BASIN GENERAL OVERVIEW

Huge data was accessible for Sirte Basin after a half century of oil exploration activities since first oil production in 1950. Since then several thousands of wells were drilled, and exploration data, such as seismic, magnetic and gravity were collected. Therefore, when compared with other areas in Libya, Sirte basin is far better known. Many studies were published regarding the depositional environment in Sirte, e.g. Gumati and Nairn, Gumati and Kanes, van der Meer and Cloetingh and Baird, et al.

Furthermore, Suleiman, et al presented results of a gravity study of the Sirt Basin. The area of Sirte Basin is estimated to be of about 600,000 km² in central of Libya with basin-fill in thickness of 7500m. The control of natural faults of Sirte Basin shelf was critical for oil migration. A number of deep wells penetrated the basement in Sirte basin and overall encompasses Parisian accreted oceanic promenade north of latitude 27 °N (see Harding, 1994). The eastern Sirte covers the most compound petroleum systems in Libya. Several potential source rocks exist and signs of significant accumulation of oil from different sources observed. Such accumulations are depicted in Fig. 1, e.g. the giant fields of Messiah, Sarir, Jalu and Abu Attifel, and the contiguous highs host the Amal and An Nafurah-Awjilah fields. Ibrahim (1991) has provided evidence that these figures were most likely correct.

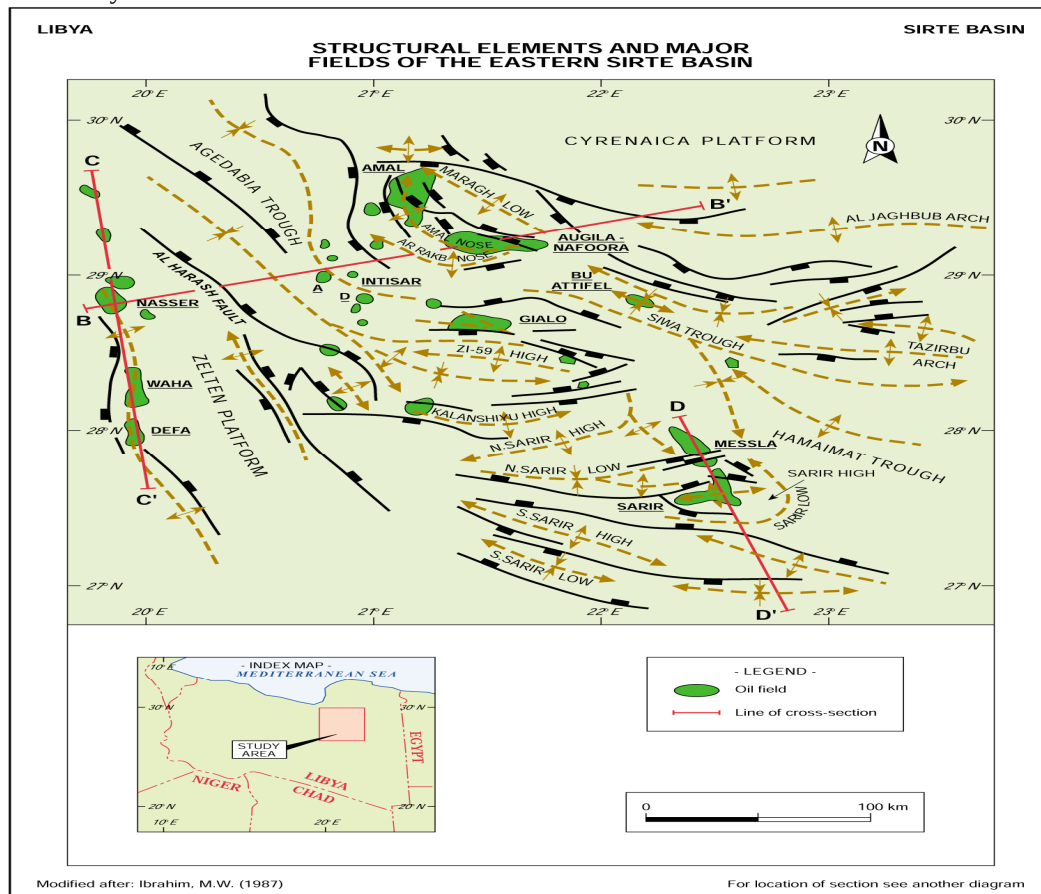


Figure 1: Structural Elements and major fields of the eastern Sirt basin (Ibrahim, 1991).

The Sirt Basin contains about 89% of all the known hydrocarbons accumulations in Libya. This can be attributed to three main factors, the Mesozoic-Cenozoic age of the basin, the presence of a rich and prolific source rock in the Upper Cretaceous Sirt Shale, and the late age of oil generation and migration (mostly in Cenozoic, and much of it in late Cenozoic). In 1980 Parsons et al. categorised hydrocarbon discoveries based on reservoir age, trap type, reservoir type, age of top seal, reservoir depth and reservoir temperature (Table 1). Whilst many discoveries have been made since then, the data was still valid. The table showed that the Lower Cretaceous (Nubian) Sandstone was the most prolific reservoir, followed by Palaeocene carbonates and then Upper Cretaceous elastics. More than 80% of the oil was found in structural traps, and almost 50% of the fields were in the depth range 2400 to 3200 m and a temperature range of 66 to 93°C. A recent review was made by Baird et al.

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

Parsons, et al. (1980) claimed that the Sirt Basin can be characterised by four main features: excellent reservoirs in both Elastics and Carbonates, major Shale and Evaporate seals throughout the succession, an abundance of structures mostly related to the tensional regime which dominated the history of the basin, and a thick and mature oil prone source rock. No estimates have been published of the amount of oil generated in the Sirt Basin, but even assuming a 2% trapping efficiency (which was high) it must amount to at least 5.8 trillion barrels. This would imply generating a capacity of about 0.25 barrels per m³ of source rock which is more than 1% total organic carbon (TOC). To date approximately 117 billion barrels of oil in place have been discovered in the Sirt Basin of which 93 billion barrels were contained in nineteen giant fields.

Although the Sirt Shale was by far the most important source rock in the basin, several other sequences also with source potential have been recognised, including the Triassic, Nubian and Turonian Shales. The Sirt Basin petroleum systems will be discussed in five areas: the western area centred on the Zallah Trough, the Maradah Trough, western Ajdabiyah Trough, eastern Ajdabiya Trough and eastern Sirt embayment (see Vail, 1991).

Table. 1 Sirt Basin, Classification of Hydrocarbon Discoveries

SIRT BASIN, CLASSIFICATION OF HYDROCARBON DISCOVERIES, 1980.									
By age of top seal		By reservoir age		By trap type		By reservoir type		By reservoir depth	
								By reservoir temperature °C	
Oligocene	8.4%	Oligocene-Eocene	8.4%	Structural	83.7%	Carbonate	42.2%	0 - 600m	-
U. Palaeocene	20.7%	Palaeocene	33.8%	Stratigraphic	16.3%	Clastic	57.8%	600 - 1200m	14%
L. Palaeocene	27.1%	U. Cretaceous/ Palaeozoic	28.3%					1200 - 1800m	25%
Cretaceous	43.8%	Cretaceous sandstones	25.5%					1800 - 2400m	6%
								2400 - 3200m	49%
								Below 3200m	6%
									10 - 38°C
									38 - 68°C
									66 - 93°C
									93 - 121°C
									121 - 149°C
									14.3%
									23%
									53%
									8%
									2%

Source: Parsons, et al., 1980

4. GEOLOGICAL SETTING

Libya is located on the Mediterranean foreland of the African Shield, extending over several sedimentary basins. Several tectonic movements and events formed the present major structural and tectonic features, including Caledonian, Hercynian Orogenies of Paleozoic time, and disturbances during Cretaceous to Middle Tertiary times (see Conant and Goudarzi, 1967). These events have resulted in uplifting, subsidence, tilting, and faulting. Libya has been subdivided into major sedimentary basins (Fig. 2).

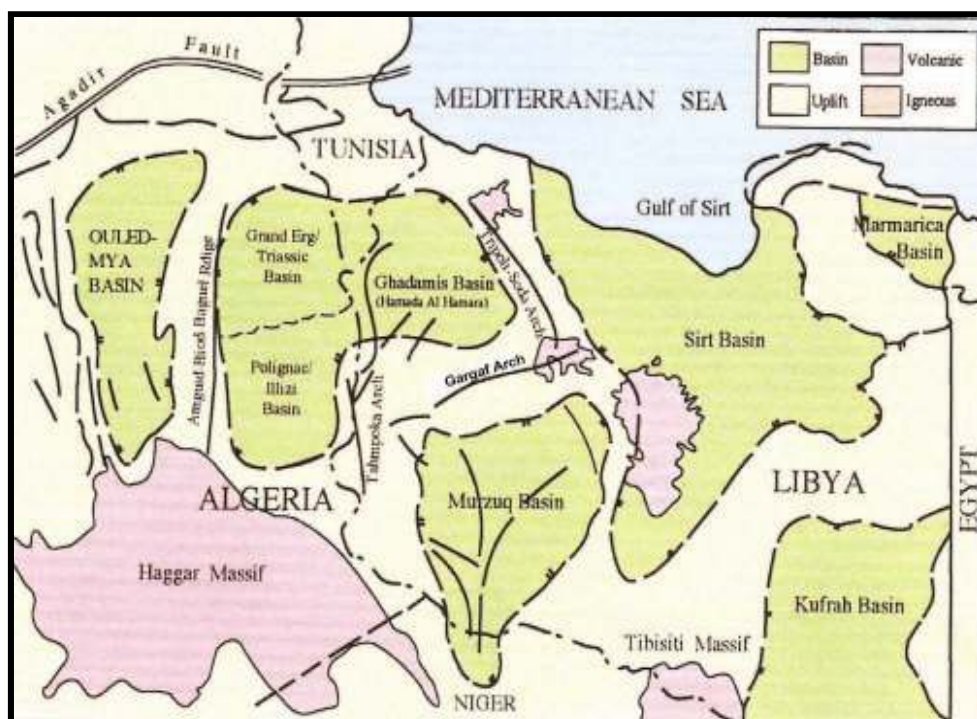


Figure 2: Sedimentary Basins as depicted in Geographical location map (after Clifford, 1986)

Sirt basin was the youngest and most hydrocarbon prolific basin in Libya. Tectonically the Sirt basin was a Northwest elongated basin made of a series of Northwest-Southeast trending platforms (Horsts) and Troughs (Grabens) as shown in figure 3. The basin has subsided slowly during Cretaceous and Tertiary, particularly in the Eocene time when the maximum rate of Subsidence of the basin was reached (Berggren, 1964). After the opening of the Sirt Basin, the Sea transgressed Southward in the subsiding Grabens and in the low-standing highs which were subsiding at a slow rate. The Sea transgression reached Latitude 22 during the late Cretaceous and Paleocene; consequently, most of the major highs were covered by the Sea. During the early Eocene, a partial regression of the sea occurred creating restricted conditions over the south-western part of the basin. New marine transgression occurred in the middle Eocene eliminating those restricted conditions. The marine sedimentation prevailed and continued until the Quaternary, when the basin was covered by continental sediments. Sedimentation in the Basin varies from thick accumulations of organic-rich bituminous Shale and deep marine carbonates to shallow marine carbonates and Evaporates and so on and so forth. The Cycles could be resulted as per changes in the sediment Supply, from reactivation of faults or from rapid subsidence. Several writers (Conley, 1971; Futyan and Jawzi, 1996; Guiraud and Bosworth, 1997) argue that Sirt Basin province was investigated to be a continental rift holotype of a (extensional) area which was known as part of the Tethyan rift system.

Futyan and Jawzi (1996) discuss in details the Tibesti Arch/Alma Arch uplift. The Cyrenaica platform (also known as Shelf including both uplift and basin) was profiling northeastern and eastern boundaries. The western boundary called the Western Shelf (see Fig. 2), it was aggregated of northwest-trending (extension) known as Fazzan Uplift (Tripoli-As Sawda Arch) and Nubian Uplift (Ahibrandt, 2001).

The Sirt Basin region was known as a continental rift holotype (extensional area) as well as was countered as part of the Tethyan rift system (see Futyan and Jawzi, 1996; and Guiraud and Bosworth, 1997). The weakness of the area structurally was illustrated by discontinuous periods of subsidence uplift and arising in the late age of Precambrian. That began with Pan African Orogeny which developed several proto-continental fragments as part of early Gondwanaland (Kroner, 1993).

153 The history of Early Paleozoic of Sirte Basin imitated a relatively uninterrupted Paleozoic Cratonic sag
 154 basin (Ahibrandt, 2001). In the Early Cretaceous the rifting started, in the Late Cretaceous reached the
 155 peak, and in the Early Tertiary age was completed. This resulted in triple junction (Tibesti, Sarir and
 156 Sirte arms as depicted in figure Figure 3) within the basins (see Ambrose, 2000). However, this rifting
 157 emulated Sinistral shear in east-west zones (strike-slip) which firmly restricted clastic deposition in Sarir
 158 arm (as mentioned by Anketell in 1996).
 159

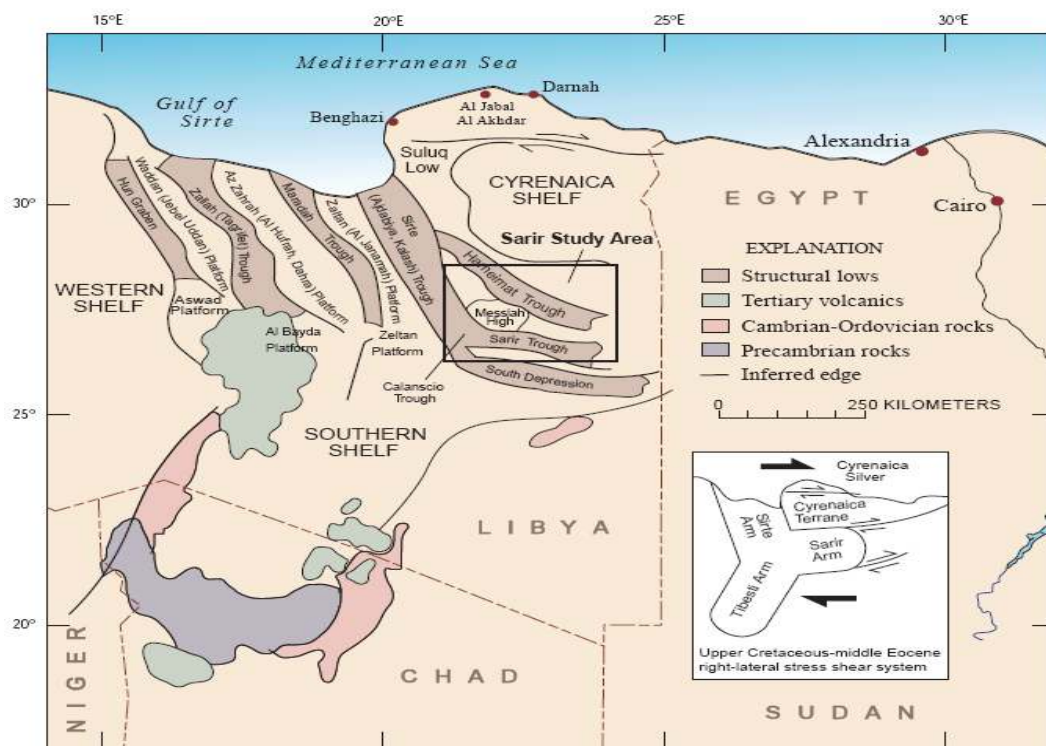


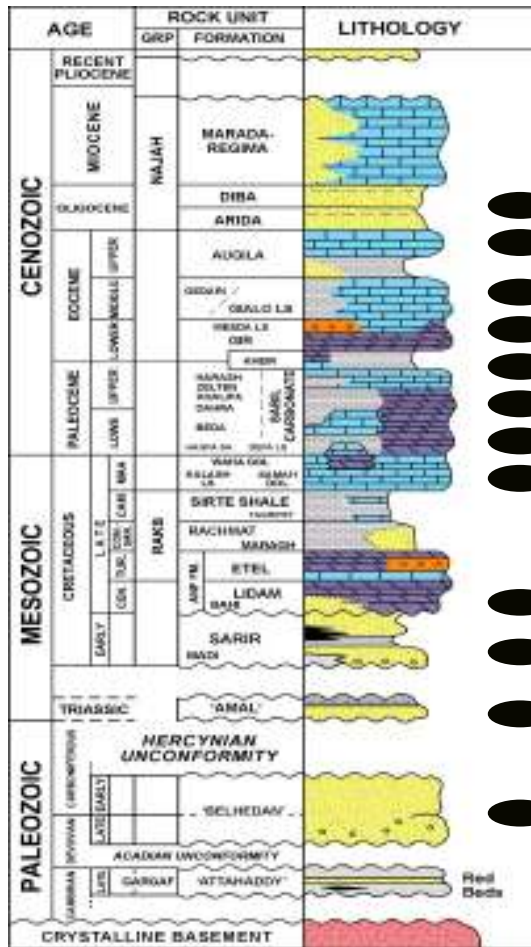
Figure 3: Sirte Basin map of Structural elements.

162 Platforms, troughs, horsts and grabens were identical terms. Horsts and Grabens particularly have
 163 multiple names. For example Sirte trough was also known as Kalash or Ajdabiya trough, (Ahibrandt,
 164 2001).
 165

4.1 LITHOLOGY

166 The name Amal Formation has recently been used for a formation in the subsurface of the Amal Field
 167 area (see Roberts, 1970). However, it was not formally proposed as a new formation nor was a type
 168 section established at the same age.
 169

170 Therefore, the Amal Formation was here proposed as a new formation in the subsurface of the eastern
 171 Sirte Basin; however, it was identical to the rock unit used by Roberts. The type section was located
 172 in the Mobil B1-12 Well at a drill depth of 9829 to 11,290 feet (total depth), which corresponds to a
 173 subsea depth of 9688 to 11,149 feet. The base of the formation was not reached.
 174



The Amal Formation was predominantly a sandstone sequence. It was heterogeneous in colour, grain size and sorting. In colour, the sandstones range from white to red, purple, tan and gray. The tan, white and gray colours were dominant. The grain size ranges from very-fine sand to cobbles with the medium to coarser grain sizes being more common. Sorting was generally poor, and conglomerate beds were frequent. Quartz was the dominant detrital material as well as the most important cementing agent. Accessory constituents were feldspar, mica, pyrite, hematite and various dark minerals. Clays, sericite and rarely dolomite were found as cementing materials in much of the formation. Generally the sandstones were firmly cemented, and orthoquartzites were common, particularly in the upper parts of the formation. Interbedded with the sandstone, but comprising a much lesser part of the formation, were graysilty clays, gray/ green/ red brittle, and micaceous shales.

In addition to the sedimentary rocks, volcanic rocks in the form of dikes, sills or flows were found at a number of horizons in the upper parts of the formation.

Within Amal formation, siltyclaystone and volcanogenic were both intrusive and extrusive. It was poorly chronostratigraphically constrained. No sufficient data were available about existence and distribution of polynoflora apart from barren of fossils.

Figure 4: Central Sirte Basin, Stratigraphic
(Tibesti and Sirte arms) (Ahibrandt, 2007)

5 DATA SUMMARY

The input data was provided by Harouge Oil Operation Company including reservoir properties, fluid properties, composite logs, well schematic and production history. Halliburton Company provided Insite for Stimulation (IFS) package including Insite Core and Insite Stimulation software products. Heriot Watt University provided Wellflo Software. Insite for Stimulation (IFS) is a realtime data acquisition System based on Insite Core and Insite Stimulation software products. For production enhancement, IFS was the initial module used for data acquisition in the workflow. Other steps were taken by Halliburton Management System (HMS) HMS recorded the processes implemented. The work frame at such level was more comprehensive than at the HMS system. Therefore, a new workflow was required.

6 METHODOLOGY AND PROCEDURES

After studying the geology and mineralogy of the formation, a design was made by wellflo before and after the treatment. This is to ensure an optimized operation and to evaluate the expected gain for economics considerations.

The damaged zone was estimated from various sources (e.g. the drilling report, the completion report, the production history). This analysis is used for the calculations of the volume of the treatment acid required for the operation. Permeability variations in addition to presence of water are two important requirements for a successful acid diversion. As mentioned above, this technique is newly presented in Libya. Finally, injectivity test was performed in order to calculate the injection rate. The formation responded positively to the treatment design. The recommended volumes were 22.1 gal / ft as shown in the table 2. This technique is known as wellbore clean-out used for improving permeability and removing damage within 2-3 feet of the reservoir. Based on reservoir study, the damage was reported within this range and the plan was made accordingly.

Below we provide details on the process followed.

6.1 The proposed treatment for Stage 1 consists of:

- 200 gal of Pickling Treatment.
- 12000 gal of Main Treatment 15% HCL Acid with Additives
- 2500 gal of Guidon (Diverter).
- 5000 gal of Displacement of Water (non-Corrosive Fluid).

6.2 The actual treatment program performed as follows:

- 12200 gal of Main Treatment 15% HCL Acid with Halliburton Additives
- 2500 gal of Guidon (Diverter).
- 6720 gal of Displacement of Water (non-Corrosive Fluid).

Table 2: Amal 'B' Formation Treatment Design and recommended Volumes.

HALLIBURTON DESCRIPTION	WT - VOL	UNIT	Comments
PE ACID 15% Hydrochloric	12200	GAL	Main Treatment
WATER	4722	GAL	Fresh Water
HYDROCHLORIC, 22 BAUME, gals	6160	GAL	Raw Acid
HAI-OS CRSN INHIB, gals	61	GAL	Corrosion Inhibitor
FE-1A ACETIC ACID - gals	122	GAL	pH Control
FE-2, lbs	330	LBS	Iron Chelating Agent
CLA-STA XP, gals	120	GAL	Clay and Fine Control
MUSOL®, gals	990	GAL	Mutual Solvent
Losurf-300M, gals	24	GAL	Surfactant
Guidon	2500	GAL	Diverter
WATER	2387	GAL	Fresh Water
HPT-1, gal	108	GAL	Polymer
BA-20, gals	5	GAL	pH Control
KCL, lbs	440	LBS	Salt

6.3 Pumping Unit & Fluid Transport trailers

Pumping unit was able to blend and pump up to the maximum pressure and maximum rate through the well head. Data measurement and control was essential to ensure a successful acidizing operation. The fluid transport trailer used has a capacity of 6200 gal including acid treatment, additives, and diverters.

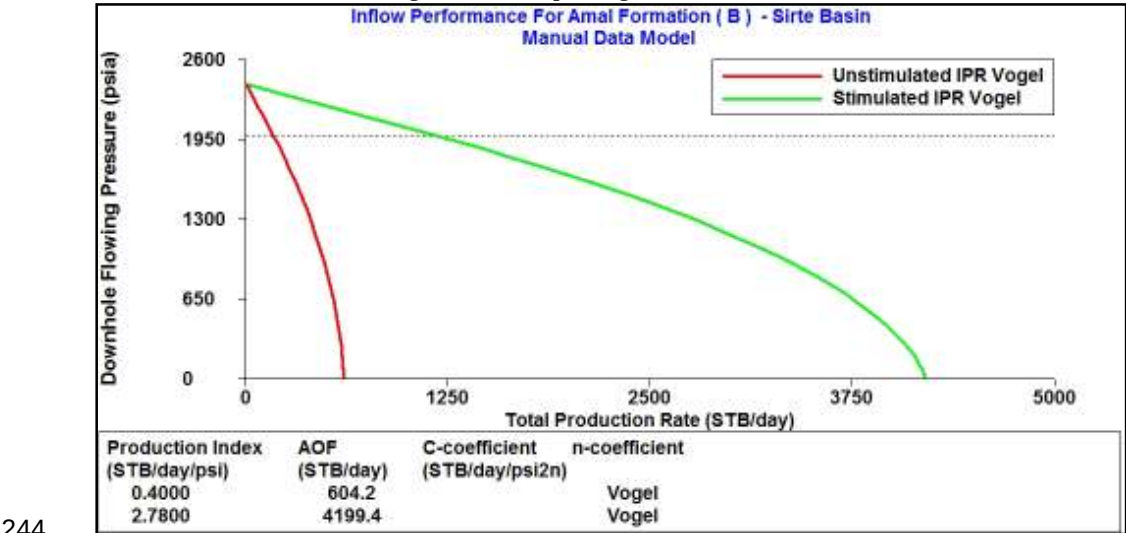
7 RESULTS AND DISCUSSIONS

Treatment timing was essential for the operation economics regardless of whether the wells were naturally flowing or using any artificial lift method... In other words, well stimulation is only justified when the net (discounted) gain of the resulting extra oil or gas production is greater than the cost of the stimulation treatment.

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

234 The purpose of Amal Reservoir 'B' treatment was to stimulate or effectively increase the flow capacity
 235 of Amal Formation. This increase was accomplished by the Acid's ability to dissolve part of the rock,
 236 certain scale, mud and other soluble material. Matrix acidizing aims to increase the well's PI by
 237 reducing Skin (Dissolving formation damage). Figure 5 shows a comparison between Inflow
 238 Performance curve (IPR) for the same well before and after treatment.
 239 After treatment the production increased by a ratio of 300% with optimum gas injection rate of 0.75
 240 MMSCF/Day and fluid level increased by a ratio of 57% compared with the unstimulated well
 241 conditions. These results indicated the importance of investigating the potential production increase
 242 and the treatment cost efficiency for this formation when a campaign treatment is performed. The
 243 wells will be ranked according to the anticipated gain



244
 245 *Figure 5: Improved Inflow performance Curve from a stimulated.*

246 Initially non-corrosive fluid was pumped to ensure that there were no returns as an indication of
 247 formation depletion. This step was followed by making a decision to cut pickling stage and perform
 248 an injectivity test just before injecting the Acid for the main treatment as shown in Figure 6. The
 249 optimum injection rate was 22.1 gallon / feet. This was followed by Soaking Agitation Treatment
 250 (SAT) to improve fluid diversion as required. The main Purpose of using SAT was to remove scale,
 251 Open perforations and react with sand face region to restore near wellbore permeability. Formation's
 252 depletion analysis is shown in Fig. 6.

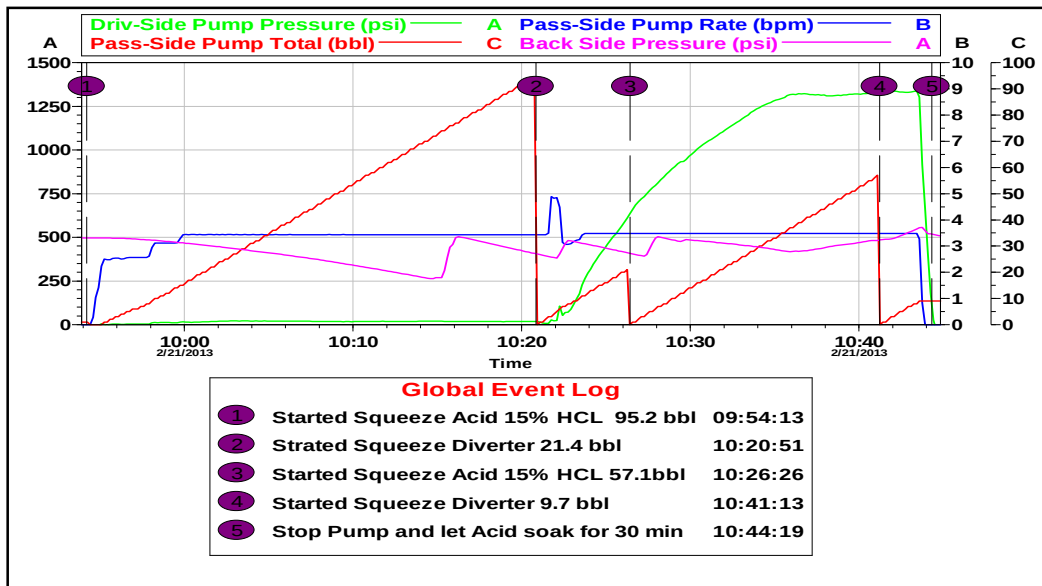


Figure 6: Squeeze Acid and Diverter before Soaking – Agitation Treatment – Stage 1.

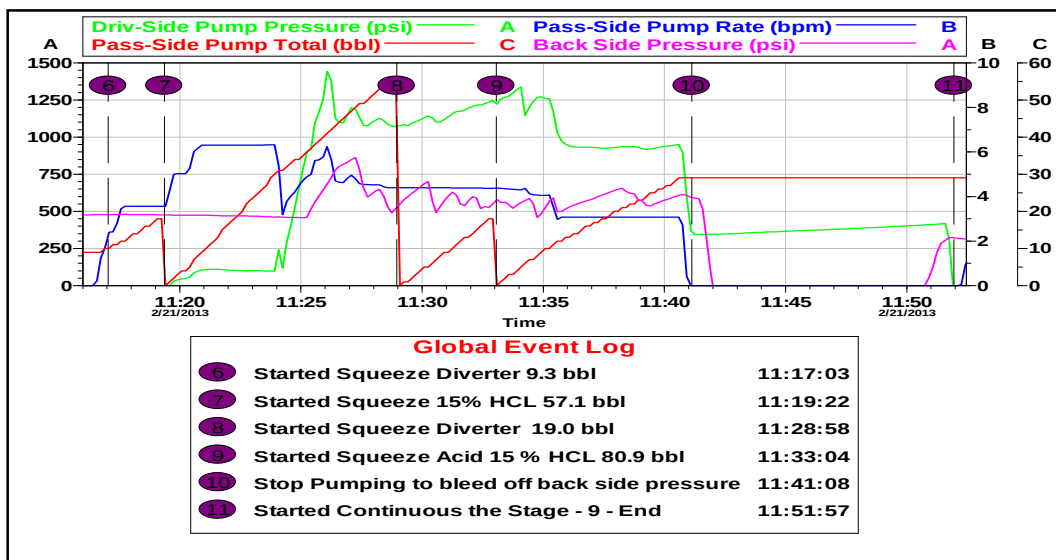


Figure 7: Squeeze Acid and Diverter after Soaking - Agitation Treatment - Stage 1

The final results of the last stage of the treatment (Switch to water displacement) detailed below and depicted in the figure 8.

- The pressure was 2104 psi and the rate was 5.136 bpm.
- The pressure was 1419 psi and the rate was 2.65 bpm.
- The pressure was 2032 psi and the rate was 3.26 bpm.
- The pressure was 2488 psi and the rate was 4.065 bpm.
- The pressure was 942.4 psi and the rate was 1.980 bpm.
- The pressure was 1194 psi and the rate was 1.960 bpm.

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

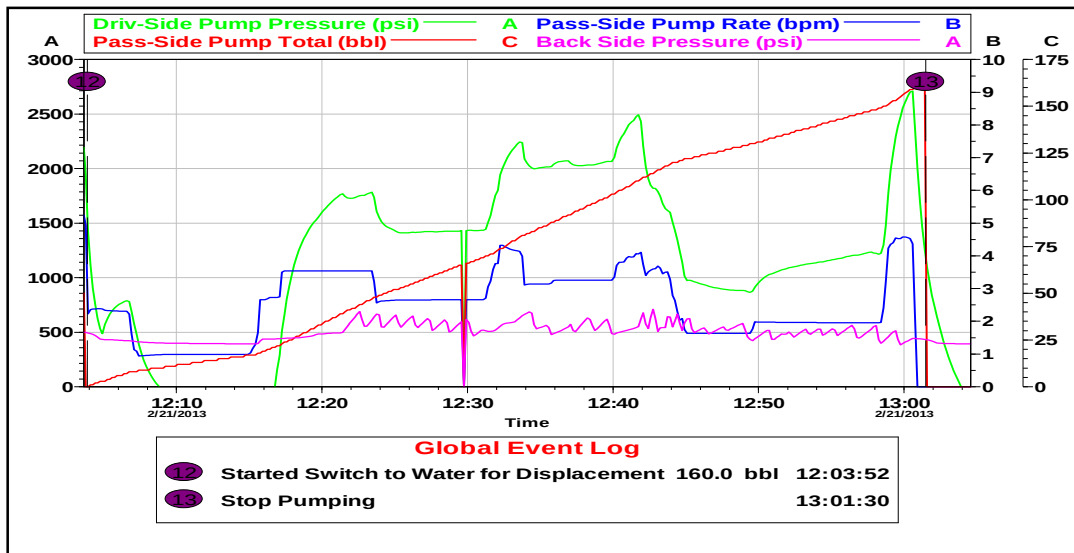


Figure 8: Switch to Water to Displace and Continue Squeeze - Stage 1

The low production wells with high skin need to be treated to assure increasing its productivity, consequently increasing the liquid rate production. Running Flowing Gradient reservoir Survey (FGS) was required for skin estimation around the wellbore (pressure transient analysis). In addition, based on the design it was found that the well's production will increase with low gas injection rate. Actual well performance proved this analysis is correct. Figures 7 to 10 illustrate comparison between stimulated and unstimulated cases, indicating the dependency of target injection point on PI. The wellflow model design was based on the actual measurements obtained from the FGS. Other concerns were considered during the design stage such as fingering or acid channelling. Based on the production performance after the treatment, the results showed that the production is slightly increasing with time indicating that diversion technique worked properly and prevented the fingering.

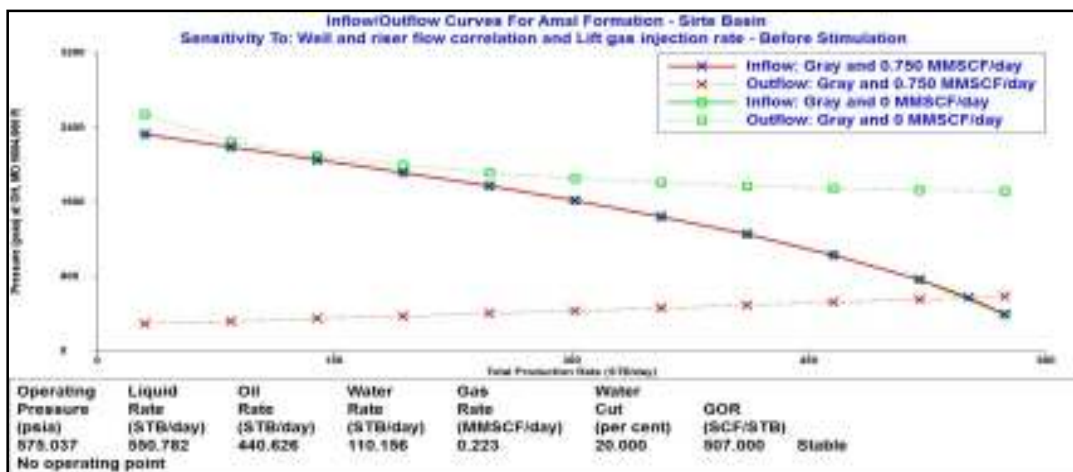


Figure 9: Inflow/Outflow curve unstimulated.

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

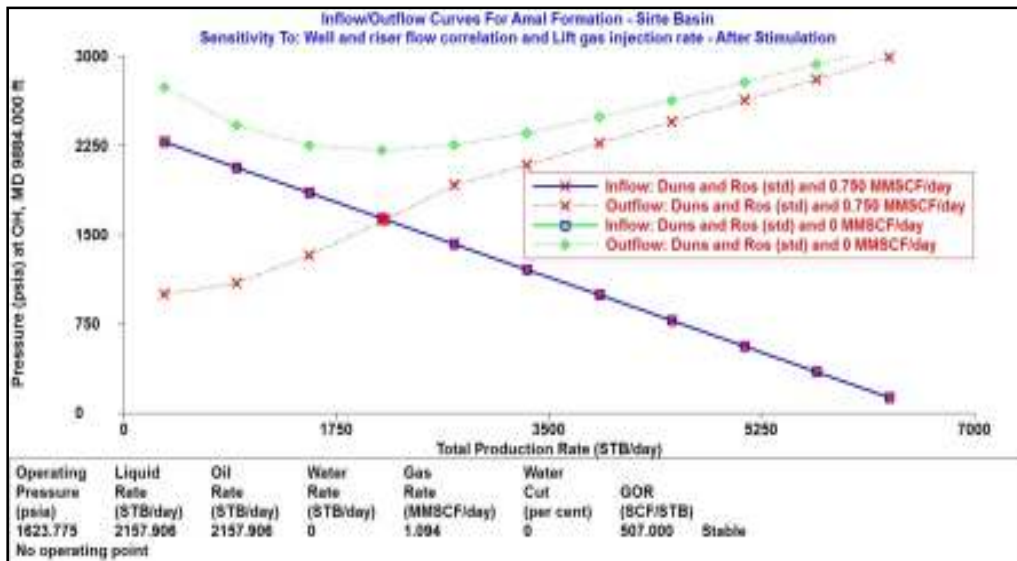


Figure 10: Inflow/Outflow curve stimulated

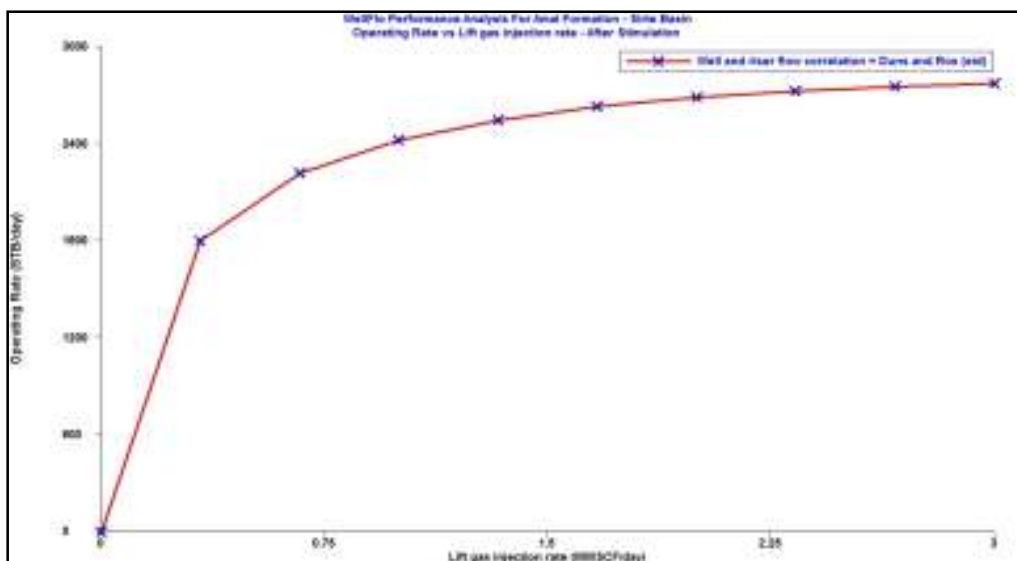


Figure 11: Lift gas injection rate after Acidizing

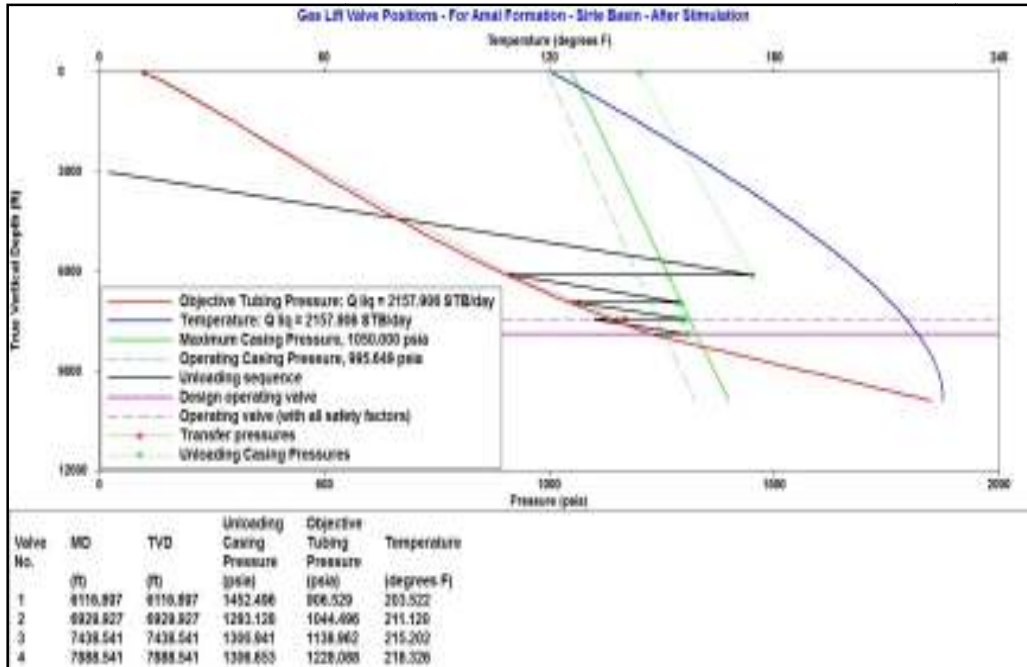


Figure 12: Gas lift positions after acidizing

7 ECONOMIC IMPACT

Based on production history, we provide below a comparison between two cases (with and without stimulation treatment). As depicted in figure 13, production forecast was estimated for the case without treatment based on 3 years production with a decline rate of 5%; on the other hand, production forecast for the treated case was estimated based on more than 3 years production after treatment with decline rate of 10%. A significant increase in production can be seen indicating that treatment was fit for purpose.

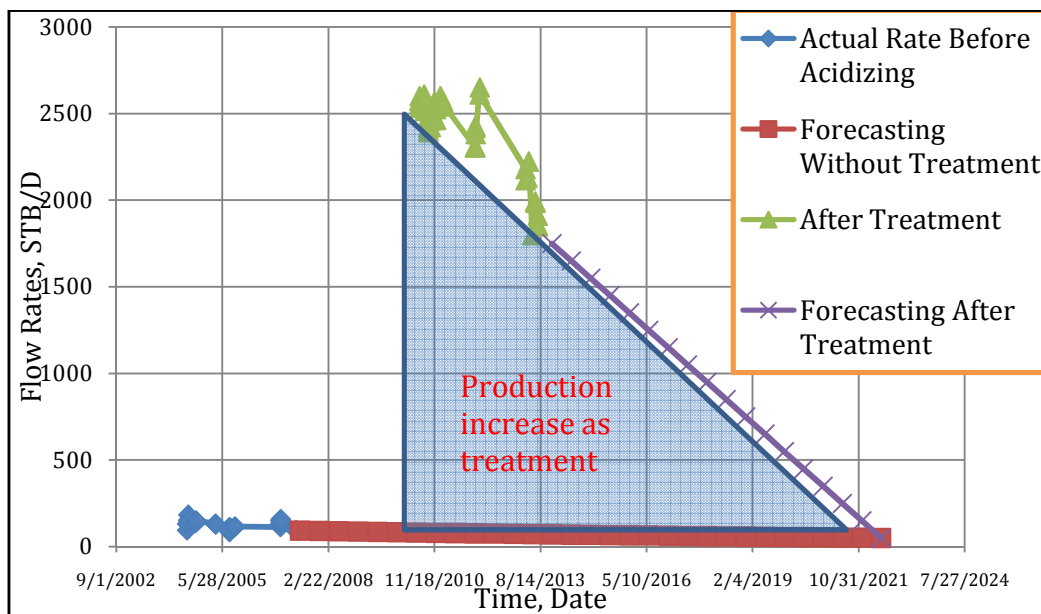


Figure 13: A comparison between treated and untreated cases with forecasting.

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

Furthermore, an economic analysis was performed in order to evaluate the economic impact of the treatment of this well. Some assumptions were implemented to estimate net present value (NPV) including crude oil price \$50, Operating Expenditure (OPEX) \$10 per barrel, and discount rate up to 20%. As shown in table 1, payback occurred in the first year with Terminal Cash Surplus (TCS) about \$226m. A Net Present Value (NPV) of \$73 million (\$2007) indicates that the treatment would generate a surplus of purchasing power of this amount when comparing to unstimulated case which had very low production rate. In this case the risk was evaluated and some uncertainties were taken in the considerations when the decision was made.

The increase in production was converted to an incremental revenue, on the other hand, there were three incremental cost elements; CAPEX, OPEX and treatment cost. In conclusion, the treatment succeeded technically and commercially.

Finally, the capacity of surface facilities is 25,000 bopd whereas the actual production was less than 10,000 bopd. This was enough to handle the increase in production. Furthermore, the pipe line size was 4 inches with 700 meters length. Therefore, the increase in production was handled smoothly without any drawbacks.

Table 2: Project Economic Impacts.

N	Year	Oil Production 10 ⁶ STB	Oil Price \$	Revenue \$m (2007)	Opex \$m/STB	Capex \$m	NCF \$m	Cum NCF \$m	DF(20%) \$m	NPV \$m	Cum NPV \$m
0	2007	0									
1	2008	0									
2	2009	0									
3	2010	0.45971600	50	23	10	5	0.155487	18	18	0.578703704	11
4	2011	0.89787581	50	45	10	9	0	36	54	0.482253086	17
5	2012	0.95732025	50	48	10	10	0	38	92	0.401877572	15
6	2013	0.72309539	50	36	10	7	0	29	121	0.334897977	10
7	2014	0.58403475	50	29	10	6	0	23	145	0.279081647	7
8	2015	0.51098475	50	26	10	5	0	20	165	0.232568039	5
9	2016	0.43793475	50	22	10	4	0	18	183	0.193806699	3
10	2017	0.36488475	50	18	10	4	0	15	197	0.161505583	2
11	2018	0.29183475	50	15	10	3	0	12	209	0.134587986	2
12	2019	0.21878475	50	11	10	2	0	9	218	0.112156655	1
13	2020	0.14573475	50	7	10	1	0	6	224	0.093463879	1
14	2021	0.07268475	50	4	10	1	0	3	226	0.077886566	0.23

8 CONCLUSION

The acid stimulation treatment implemented in Amal Formation has successfully resulted in lowering the near well-bore pressure losses, removing the skin and improving the overall well productivity.

Two factors were found responsible for the additional pressure drop near the wellbore:

1. Amount of the permeability impairment, which was measured as a permeability reduction.
2. Radial thickness of the impaired or damage area.

Stimulation of Amal 'B' was achieved by a 15% HCL acid with additives and Guidon as diversion system.

After treatment the Production increased by a ratio of 300% by optimum gas injection rate of 0.75 MMSCF/Day and fluid level increased by a ratio of 57% compared with the unstimulated well conditions. The lessons learnt shall be implemented in a proper designed campaign considering all producers of Amal formation.

During designing an acid job, engineers must be aware of the various possible types and sources of formation damage. The well history and operations' reports should be reviewed carefully in order to successfully identify the main causes of extra pressure drop near the wellbore.

The engineer should also understand the most common types of formation damage that may occur during acidizing treatment such as formation de-consolidation, fines mobilization,

334 reactionbetween chemicals, chemicals incompatibilities,precipitation of iron compounds, emulsions
 335 and sludge.
 336 The criteria used to choose the optimum injection rate was basically called the technical optimum
 337 injection rate. However, the economic optimum gas injection rate will be relatively low. It was
 338 denoted as the economical gas injection rate at which the marginal cost of providing extra injection
 339 gas was equal to the marginal revenue of the extra well production gained from the extra gas
 340 incremental.Nevertheless, Down-hole sampling, PVT, special core analysis were required to have a
 341 better vision and design. Moreover, for fine tuning a good reservoir and geological description like
 342 bed thicknesses, faults, fractures, rock type, geometry and structure through extra seismic acquisition
 343 were very powerful.
 344

345 **COMPETING INTERESTS**

346 Authors have declared that no competing interests exist.
 347

348 **ABBREVIATIONS**

349 AOF:	Absolute Open Flow
350 API:	America Petroleum Institute
351 bbl/min:	Barrel per Minute
352 Btm:	Bottom
353 CAPEX:	Capital Expenditure
354 DPC:	Differential pressure casing
355 EPSE:	Edinburgh Petroleum Services
356 FBHP:	Flowing Bottom Hole Pressure
357 Ft:	Feet
358 FWHP:	Flowing well head pressure
359 Gal:	Gallon
360 G.O.R:	Gas Oil Ratio
361 G.L:	Gas Lift
362 HCL:	Hydrochloric Acid
363 HMS:	Halliburton Mangment System
364 IPR:	Inflow Performance Relationship
365 Kh:	Permeability Thickness
366 MMSCF/d:	Million standard cubic feet per day
367 MD:	Measured Depth
368 Md:	Milli Darcy
369 MPP:	Mid Perforation Point
370 NPV:	Net Present Value
371 OP:	Operating Pressure
372 OPEX:	Operation Expenditure
373 Perf:	Perforation
374 PI:	Productivity Index
375 Pr:	Reservoir Pressure
376 PSI:	Pounds Square Inch
377 Pso:	Surface Opening Pressure
378 Pt:	Tubing Pressure
379 PVT:	Pressure, Volume and Temperature
380 Pwf:	Well Flowing Pressure
381 S:	Skin
382 Tbg:	Tubing
383 TCS:	Terminal Cash Surplus
384 TD:	Total Depth
385 TVD:	True Vertical Depth
386 VLP:	Vertical Lift Performance

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com

387 W.H: Well Head
388 WC: Water Cut
389

390 REFERENCES

- 391 1. Baird, W., Aburawi, M. and Bailey L. (1996) Geology and Petroleum in the Central Sirt
392 Basin, in Salem, J., El-Hawat, S. and Sbeta, M., (ed.), *The Geology of Sirt Basin*,
393 Amsterdam, Elsevier, Vol. 3, pp 43
- 394 2. Barr, T. and Weegar, A (2008) Stratigraphic Nomenclature of the Sirte Basin, Libya,
395 Tarxien, Gutenberg Press Limited
- 396 3. Conley, D. (1971) 'Stratigraphy and lithofacies of Lower Paleocene rocks, Sirte basin', In:
397 Gray, C. (ed.), *Symposium on the Geology of Libya*, Tripoli, University of Libya, pp. 127–
398 149
- 399 4. Davies, D. (2014) 'Production Technology', Edinburgh, Heriot Watt University, PP 425-474
- 400 5. Ehinger, B., Zucker, L., Bergstrom, A., Seiler, M., Aramant, B., Gustavii, B., and Adolph,
401 A. (1991)
- 402 6. Guiraud, R. and Bosworth, W. (1997) 'Senonian Basin inversion and rejuvenation of rifting
403 in Africa and Arabia-Synthesis and implication to plate-scale tectonics', *Elsevier*,
404 *Tectonophysics*, v. 282, pp. 39-82.
- 405 7. Futyan, A. and Jawzi, H. (1996) 'The hydrocarbon habitat of the oil and gas fields of North
406 Africa with emphasis on the Sirt Basin', in Salem, J., El-Hawat, S., and Sbeta, M., (ed.), *The*
407 *geology of Sirt Basin*, Amsterdam, Elsevier, v. 2, pp. 87-308
- 408 8. Gumati, D. and Kanesh, H. (1985) Early Tertiary Subsidence and Sedimentary Facies –
409 Northern Sirte Basin, Libya, Tulsa, American Association of Petroleum Geologists Bulletin,
410 V. 19, p. 39-52
- 411 9. Hallett, D. (2002) *Petroleum Geology of Libya*, Amsterdam, Elsevier Science B.V., pp. 503
- 412 10. Harding, P. (1984) Graben Hydrocarbon occurrences and structural Style, American
413 Association of Petroleum Geologists Bulletin, V. 68, P. 333-362
- 414 11. Ibrahim, W. (1992) 'Prospectivity of the Sirt group sands, eastern Sirte basin, Libya', In 3rd
415 *Symposium of the Geology of Libya*, Tripoli, College of Science, Tripoli University, Vol. 7,
416 pp 2757-2779.
- 417 12. Vail, M. (1991) *'Retinal Degeneration'*. Boca Raton, CRC Press Inc, pp 2262
- 418 13. Klitzsch, L. and Kogbe, A. (1989) 'Continental Sediments in Africa', O.E.T. pp 256-257.
- 419 14. Klitzsch, E., (1996) 'Geological observations from Nubia and their structural interpretation',
420 In Salem, J., Busrewil, T., Misallati, A., and Sola, A. (Ed.), *The Geology of Sirt Basin*,
421 Amsterdam, Elsevier, vol. 3. pp. 256-257
- 422 15. Macgregor, S. (1996) The Hydrocarbon System of North Africa, Marine and Petroleum
423 Geology, Oxford, Butterworth-Heinemann LTD, Vol. 13, p. 329-340.
- 424 16. Macgregor, S. and Moody, J. (1998) Mesozoic and Cenozoic Petroleum System of North
425 Africa, In Macgregor, S., Moody J. and Clark-Lowes, D. (ed.), *Petroleum Geology of North*
426 *Africa*, Memoris, *Geol. Soc. Special Publication No. 13* pp 212-213.
- 427 17. Parsons, G., Zagaar, M. and Curry, J. (1980) hydrocarbon occurrences in the sirte Basin,
428 Libya Facts and principles of world petroleum occurrence, Memoris, *Canadian Society of*
429 *Petroleum Geologists*, pp 723-732.
- 430 18. Roberts, M. (1970) 'Amal Field, Libya, In Geology of Giant Petroleum Fields', *American*
431 *Association of Petroleum Geologists Memoir*, Tulsa, pp. 438-448
- 432 19. Todd, A. and Somerville, J. (2013) 'Reservoir Engineering', Edinburgh, Heriot Watt
433 University pp 459-481

* Tel.: +218 91 372 4106

E-mails address: Emad.fandi@halliburton.com; Emad.fandi77@gmail.com