

Case Study

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

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ABSTRACT

Implemented a combination techniques of maximum economic, enhance well deliverability and Gas Lift Analysis. A proper design was achieved based on solid data fed several software packages leads to a success case of stimulation treatment. Nevertheless, certain steps were required to avoid causing any damage and to deal with unexpected events. This treatment was a new approach to Amal formation, even though it was implemented in the same Basin.

The main objective of this case was to pump acid throughout the perforation to damaged zone around the wellbore in order to reduce skin which cause by drilling and completion or by production. To do that, it was important to inject Break-Down Acid Job (BDAJ) technique without breaking down the formation (safety margin pressure should be not exceeded at bottom-hole).

The targeted formation responded positively to acid treatment and diversion. A significant increase in flow rate indicating that Hydraulic acid (HCl) reduced formation damage as was planned. However, in this case it was important to understand that this formation was vacuumed and applying high injection rate was essential to ensure that acid reach the target zone.

In this study a deep economic impact was analysed deeply and it confidently proved profitability of the treatment over a production life of the well. The application of this technique for the same formation will help to ensure the growth of company assets.

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

1. INTRODUCTION

This study was mainly focused on three aspects: maximise economics, enhance well deliverability and Gas Lift Analysis. It was illustrating how a proper design led to a success case of stimulation treatment. However, it was important to follow certain steps to avoid causing any damage and to deal with unexpected events. This treatment was a new approach to the targeted formation, even though it was implemented in the same Basin.

The candidate well was selected based on shortage in deliverability comparing to the other wells. A reservoir study showed that this well was drilled about 40 years ago. At that time they use insufficient

drilling fluids as well as completion procedures. In addition, there were missing parts from core samples indicating the possibility of sand migration.

The targeted formation responded positively to the acid treatment and diversion. A significant increase in flow rate indicating that Hydraulic acid (HCl) reduced formation damage and drilling fluids as planned. However, in this case it was important to vacuum the formation using non-corrosive fluids. This was essential to ensure that acid reach the target zone.

Based on geological study Amal formation was sandstone inter-bedded with thin layers of claystone. Claystone present in Amal formation were predominantly and primarily due to that the Amal formation was a sand-prone interval. Therefore, all claystone samples were collected from core as chips.

In this study a deep economic impact was analysed deeply and it confidently prove the profitability of the treatment over a production life of the well. The application of this technique for the same formation will help to ensure the growth of company assets.

2. LITERATURE REVIEW

There were many sources of formation damage which can cause a decreasing in the permeability of the near wellbore area and generation of a positive skin(see David, 2014).

As targeting formation for treatment was a sandstone reservoir, acid treatment should primarily increase the effective wellbore radius; hence increasing the area of formation surface which has direct communication with the wellbore. This goal can then be achieved by dissolving the matrix in the immediate surrounding area of the borehole, and by opening the existing perforations. A secondary objective of the treatment was to remove drilling-induced or completion fluid-contamination damage from the formation face. In addition, to clean drilling mud from natural or induced fractures for the producing wells as well as removing the completion fluid-contamination damage for the well production.

Based on semi-steady state, radial flow equation $Q = \frac{Kh(P_e - P_{wf})}{\mu B_o (Ln \frac{r_e}{r_w} + S)}$, there were two options to increase well inflow either by increasing the permeability-height factor or by decreasing skin and/or $\frac{r_e}{r_w}$. Matrix stimulation mainly improves well outflow by removing formation damage and increase 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.

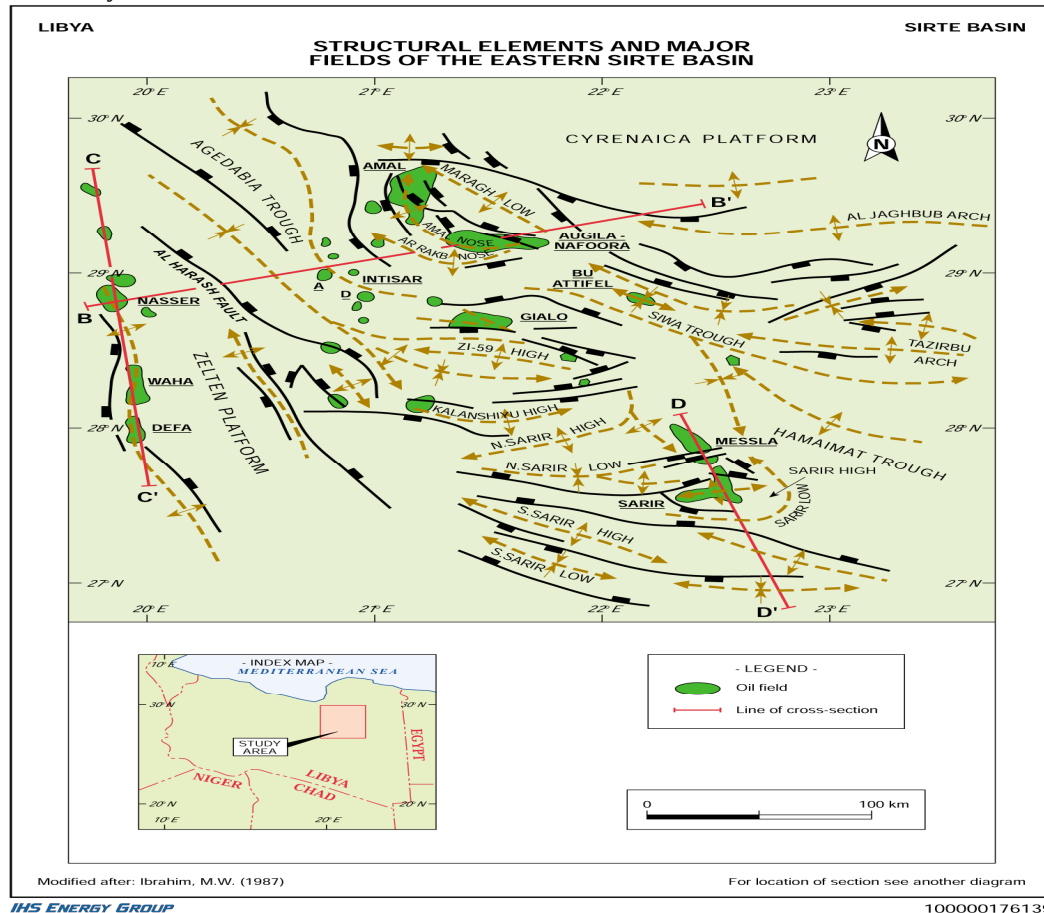
The removal of this damage was represented by Hawkins formula: $S_d = \left[\frac{K_o}{K_{do}} \right] \ln \left(\frac{r_d}{r_w} \right)$. This treatment will be success when the candidate well was capable of a greater hydrocarbon production rate, selection of the optimum type of fluid to remove skin and a proper design of the operation (see David, 2014). In addition to that it was only justified when the extra hydrocarbon production was greater than the cost of the treatment.

Basic procedures should be followed to avoid the most common mistakes in design of the operational aspects such as compatibility test and use surfactant based on temperature rule. In addition it was essential to use diversion to help ensure targeted producing zones were selectively acidized. Such additives were acting as polymer and forcing acid to follow hydrocarbon zones by changing the effective permeability where it was adsorbed; consequently the acid will be diverted to other zones.

3. SIRT BASIN GENERAL OVERVIEW

Huge data was accessible for Sirte Basin after a half century of oil exploration activities since first oil. Thereafter, several thousands of wells were drilled, as well as, seismic, magnetic and gravity data were collected. Even though, this basin can comparatively be solicited that the deep troughs were poorly identified; comparing to the other areas in Libya, it was far better known. Many studies were published regarding the subsidence history of Sirt and the best were published by Gumati and Nairn,

80 Gumati and Kanes, van der Meer and Cloetingh and Baird, et al. Furthermore, Suleiman, et
 81 al presented results of a gravity study of the Sirt Basin. The area of Sirte Basin was estimated to be
 82 about of 600,000 km² in central of Libya with basin-fill in thickness of 7500m. The control of natural
 83 faults of Sirt Basin shelf was critica, especially regarding to oil migration. A number of deep wells
 84 penetrated the basement in sirte basin and overall encompasses Parisian accreted oceanic promenade
 85 north of latitude 27 °N (see Harding, 1994). The eastern Sirt Embayment covers the most compound
 86 petroleum systems in Libya. This was due to the presence of several potential source rocks, and signs
 87 of significant collaborating of oils from altered sources. The embayment involved the giant fields of
 88 Messiah, Sarir, Jalu and Abu Attiffel, and the contiguous highs host the Amal and An Nafurah-
 89 Awjilah fields as depicted in Fig. 1. Ibrahim (1991) has provided evidence that these figures were
 90 most likely correct.



91
 92 Figure 1: Structural Elements and major fields of the eastern sirte basin (Ibrahim, 1991).

93 The Sirt Basin contains about 89% of all the hydrocarbons covered in Libya. This was primarily due
 94 to three factors, the Mesozoic-Cenozoic age of the basin, the presence of a rich and prolific source
 95 rock in the Upper Cretaceous Sirt Shale, and the late age of oil generation and migration (mostly
 96 in Cenozoic, and much of it in late Cenozoic). In 1980 Parsons et al. categorised hydrocarbon
 97 discoveries based on reservoir age, trap type, reservoir type, age of top seal, reservoir depth and
 98 reservoir temperature (Table 1). Whilst many discoveries have been made since then, the data was
 99 still valid. The table showed that the Lower Cretaceous (Nubian) Sandstone was the most prolific
 100 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.

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 a generating capacity of about 0.25 barrels per m³ of source rock with more than 1% 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	10 - 38°C
U. Palaeocene	20.7%	Palaeocene	33.8%	Stratigraphic	16.3%	Clastic	57.8%	600 - 1200m	38 - 66°C
L. Palaeocene	27.1%	U. Cretaceous/Palaeozoic	28.3%					1200 - 1800m	66 - 93°C
Cretaceous	43.8%	Cretaceous sandstones	25.5%					1800 - 2400m	93 - 121°C
								2400 - 3200m	121 - 149°C
								Below 3200m	2%

Source: Parsons, et al., 1980

4. GEOLOGICAL SETTING

Libya was situated 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. 1).



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

Sirte Basin was the youngest and most hydrocarbon prolific basin in Libya. Tectonically the Sirte basin was a Northwest elongated basin made of a series of Northwest-Southeast trending platforms (Horsts) and Troughs (Grabens) as shown in Fig 2. 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 Sirte 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 time; 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 southwestern 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 Sirte 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 Sirte 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).

157 The history of Early Paleozoic of Sirte Basin imitated a relatively uninterrupted Paleozoic Cratonic sag
 158 basin (Ahibrandt, 2001). In the Early Cretaceous the rifting started, in the Late Cretaceous reached the
 159 peak, and in the Early Tertiary it was completed. This resulted in triple junction (Tibesti, Sarir and
 160 Sirte arms as depicted in figure Figure 3) within the basins (see Ambrose, 2000). However, this rifting
 161 emulated Sinistral shear in east-west zones (strike-slip) which firmly restricted clastic deposition in
 162 Sarir arm (as mentioned by Anketell in 1996).
 163

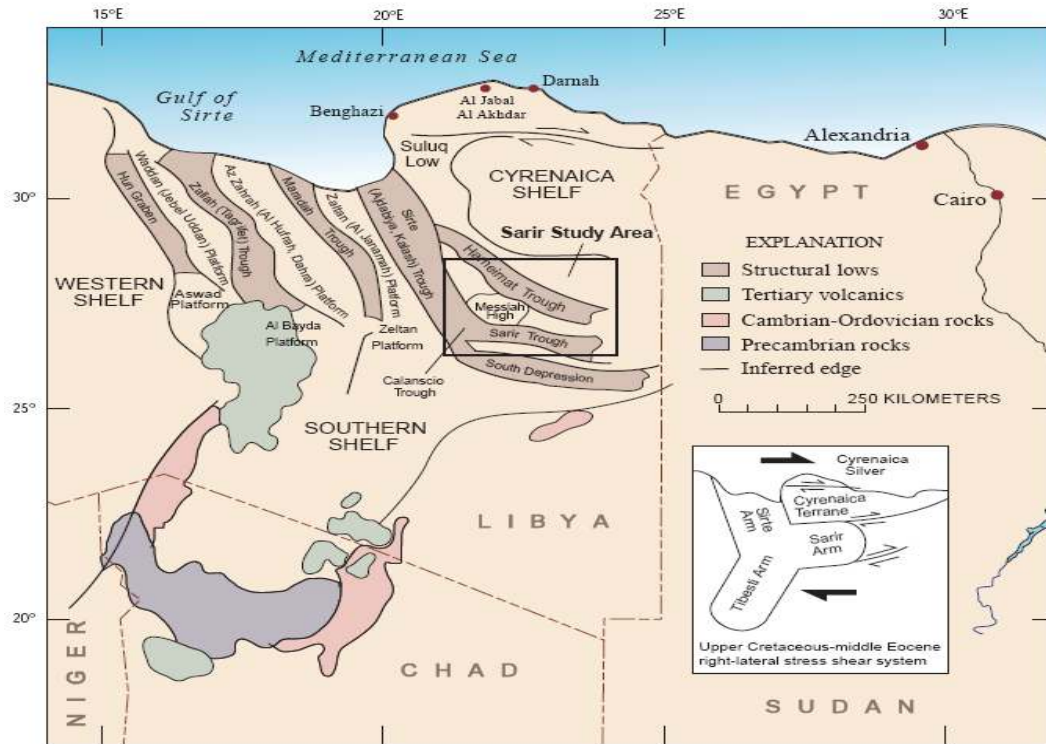


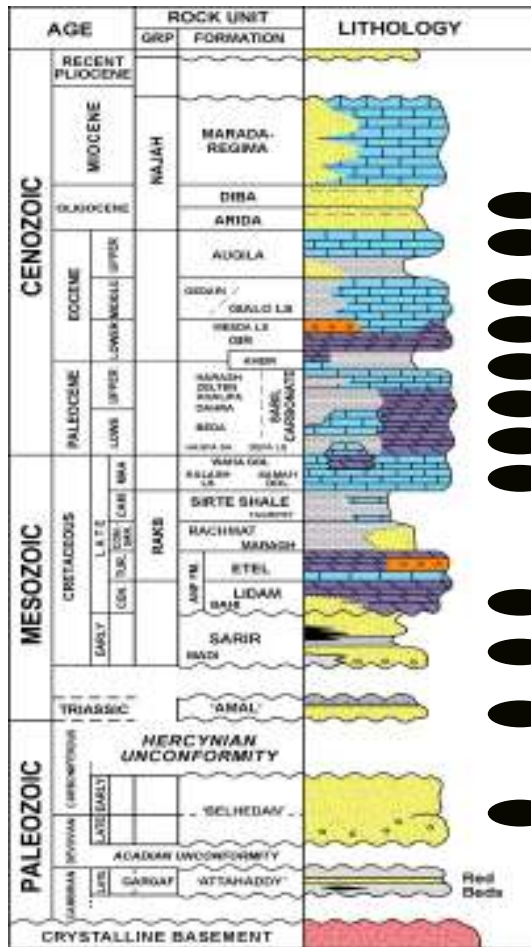
Figure 3: Sirte Basin map of Structural elements.

166 Platforms, troughs, horsts and grabens were identical terms. Horsts and Grabens particularly have
 167 multiple names. For example Sirte (Sirt) Trough was also known as Kalash or Ajdabiya Trough,
 168 (Ahibrandt, 2001).
 169

1.1 LITHOLOGY

170 The name Amal Formation has recently been used for a formation in the subsurface of the Amal Field
 171 area (see Roberts, 1970). However, it was not formally proposed as a new formation nor was a type
 172 section established.
 173

174 Therefore, the Amal Formation was here proposed as a new formation in the subsurface of the eastern
 175 Sirte Basin; however, it was identical to the rock unit used by Roberts. The type section was located
 176 in the Mobil B1-12 Well at a drill depth of 9829 to 11,290 feet (total depth), which corresponds to a
 177 subsea depth of 9688 to 11,149 feet. The base of the formation was not reached.
 178



The Amal Formation was predominantly a sandstone sequence. It was heterogeneous in color, grain size and sorting. In color, the sandstones range from white to red, purple, tan and gray. The tan, white and gray colors 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 gray silty 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, silty claystone 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

and Sirte arms) (Ahibrandt, 2001)

5. DATA SUMMARY

The input data was provided by Harouge Oil Operation Company including reservoir properties, fluid properties, PVT data, relative permeability relationship, 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) was Real Time Data Acquisition System based on Insite Core and Insite Stimulation software products. For Production Enhancement, IFS was as initial module of data acquisition processed in the workflow. This process was done while other steps taken by Halliburton Management System (HMS), which recorded the processes that were implemented. The work frame at such level was more comprehensive than at the HMS system, so more extraordinary procedure were required.

Wellflo was favorable software for design and analyse artificial lift system as well as run a variety of sensitivities. This software suite was developed by Edinburgh Petroleum Services 2006 EPS Ltd. It was a single-well nodal analysis program which models natural producers, Injectors and (optionally) gas-lifted wells.

6. METHODOLOGY AND PROCEDURES

After studying the geology and mineralogy of the formation, a design was made by wellflo before and after the treatment come up with increasing in production. However, mineralogical analysis was carried out on core samples rather than cuttings samples which contained insufficient core material. The damaged zone was estimated to calculate the volume of the treatment acid. Variety of permeability and presence of water required to use diversion as a new technique presented in Libya. Finally, injectivity test was performed in order to calculate the injection rate. The formation responded positively to Halliburton treatment design despite the recommended volumes were 22.1 gal / ft as shown in the table 1. This Technique was known as wellbore clean out to improve permeability and remove damage within 2-3 feet of reservoir. Based on reservoir study, the damage was reported within this range and the plan was made accordingly.

The process was described as follows:

5.4 The proposed treatment for Stage 1 consisted of:

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

5.5 The actual acid was pumped as follows:

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

Table 1: 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

5.6 Halliburton 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, hence data measurement and control was essential to Acidizing operation. However, each Halliburton fluid transport trailer has a capacity of 6200 gal including acid treatment, additives, and diverters.

7. RESULTS AND DISCUSSIONS

Treatment timing was essential regardless of whether the wells were natural or artificial lift as per routine and long term oil and gas production. Thus an estimation of time required for stimulation

239 treatment in order to increase well deliverability. In other words, well stimulation was only justified
240 when the net (discounted) monetary of the resulting extra oil or gas production was greater than the
241 cost of the stimulation treatment.
242 The purpose of Amal Reservoir 'B' treatment was to stimulate or effectively increase the flow capacity
243 of Amal Formation. This increase was accomplished by the Acid's ability to dissolve rock, certain
244 scale, mud and other soluble material, which cause blockage in the flow channels. However, the
245 treatment was designed to increase the well's Productivity Index (PI). Matrix acidizing aims to
246 increase PI by reducing Skin (Dissolving formation damage) as well as reducing minerals near
247 wellbore region. Figure 3 shows a comparison between Inflow Performance curve (IPR) for the same
248 well before and after treatment.
249 After treatment the Production increased by a ratio 299.4% by optimum gas injection rate 0.75
250 MMSCF/Day and fluid level increased by a ratio 57.1% which was much greater than Unstimulated.
251 Therefore, this raises the importance of investigating the potential production increase and the
252 treatment cost efficiency for this formation when carrying out stimulation campaign in order to rank
253 in terms of stimulation preference.

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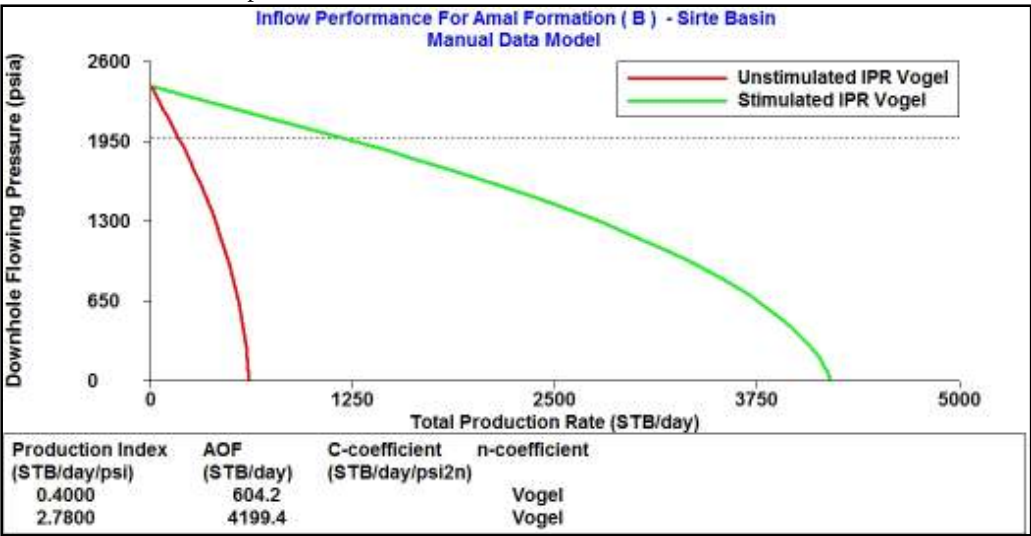


Figure 5: Improved Inflow performance Curve from a stimulated.

256 Initially non-corrosive fluid was pumped to ensure that there were no returns as an indication of
257 formation vacuum. This step was followed by making a decision to cut pickling stage and perform an
258 injectivity test just before injecting the Acid for the main Treatment as shown in Fig. 4. The optimum
259 injection rate was 22.1 gallon / feet. However, this was followed by Soaking Agitation Treatment
260 (SAT) to improve diverting. The main Purpose of using SAT was to remove scale, Open perforations
261 and React with the formation face. Formation's vacuum process was shown in Fig. 5.

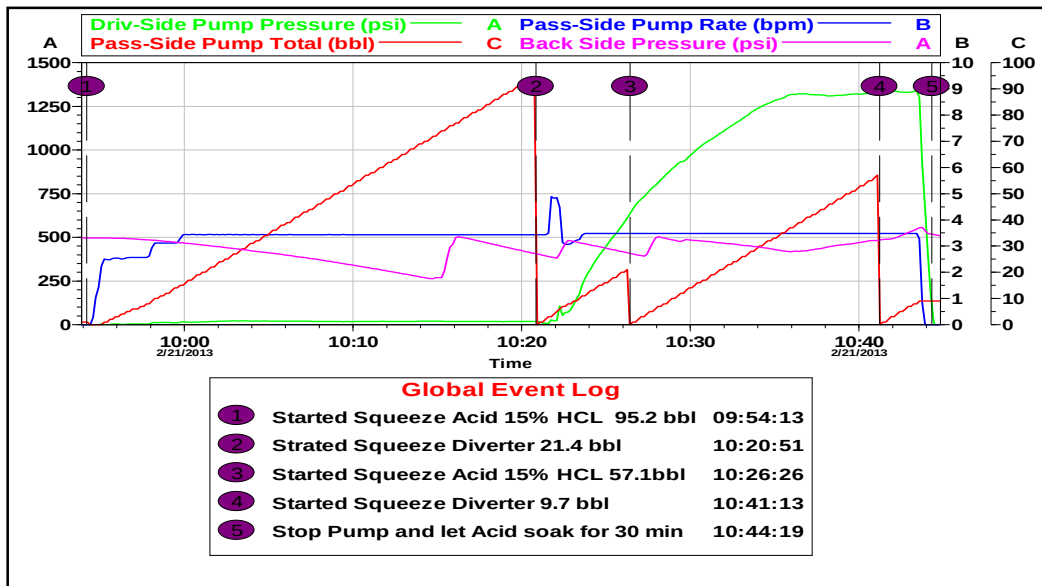


Figure 6: Squeeze Acid and Diverter before Soaking – Agitation Treatment – Stage 1.

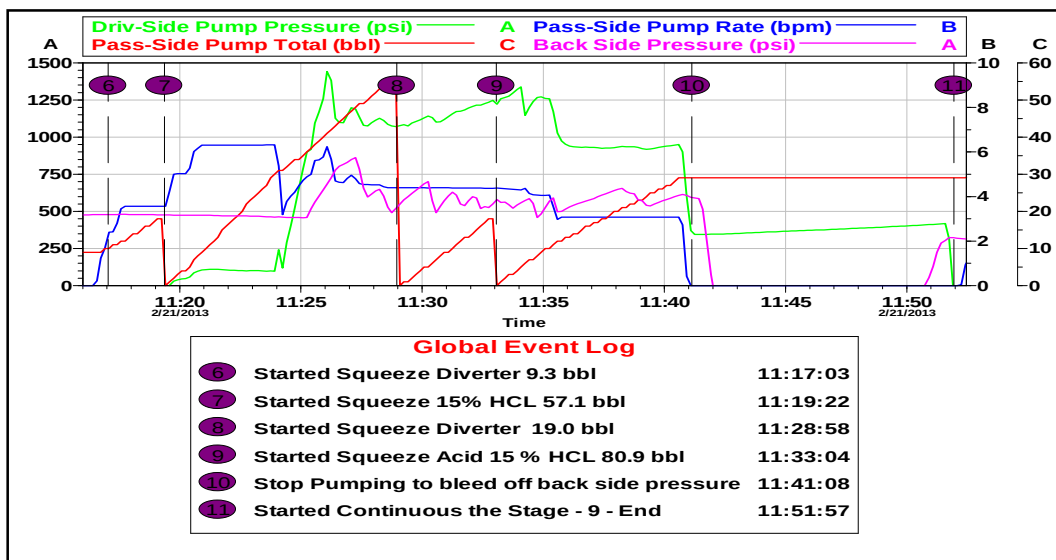


Figure 7: Squeeze Acid and Diverter after Soaking - Agitation Treatment - Stage 1

The final results of Squeeze at the last stage (Switch to water to displace) as detailed below and depicted in the Fig 6.

- 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.

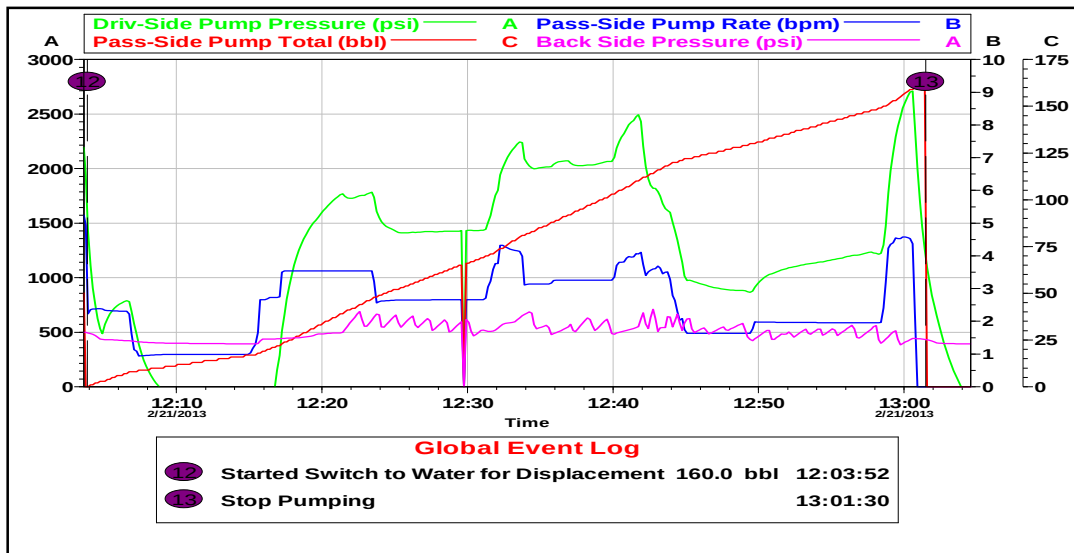


Figure 8: Switch to Water to Displace and Continue Squeeze - Stage 1

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 damage evaluation around the wellbore. However, based on the design the production will increase with low gas injection rate. Concrete results support the statement. Figures 7 to 10 illustrate comparison between stimulated and unstimulated cases, indicating the dependency of target injection point on PI.

The pressure / depth which modelled was compared to actual measurements obtained by running the FGS gave best match with Duns and Ros (Std) correlation, even though unstimulated was Gray on it. Other concerns were considered during planning such as fingering due to acid could follow channels. Based on the history production after the treatment, the results showed that the production slightly increasing with time indicating that diversion worked properly and prevent the fingering.

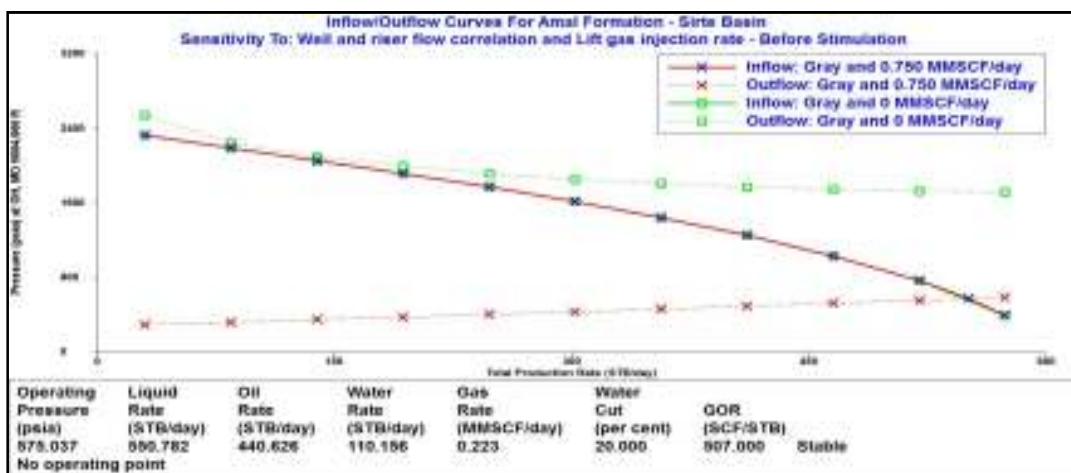


Figure 9: Inflow/Outflow curve unstimulated.

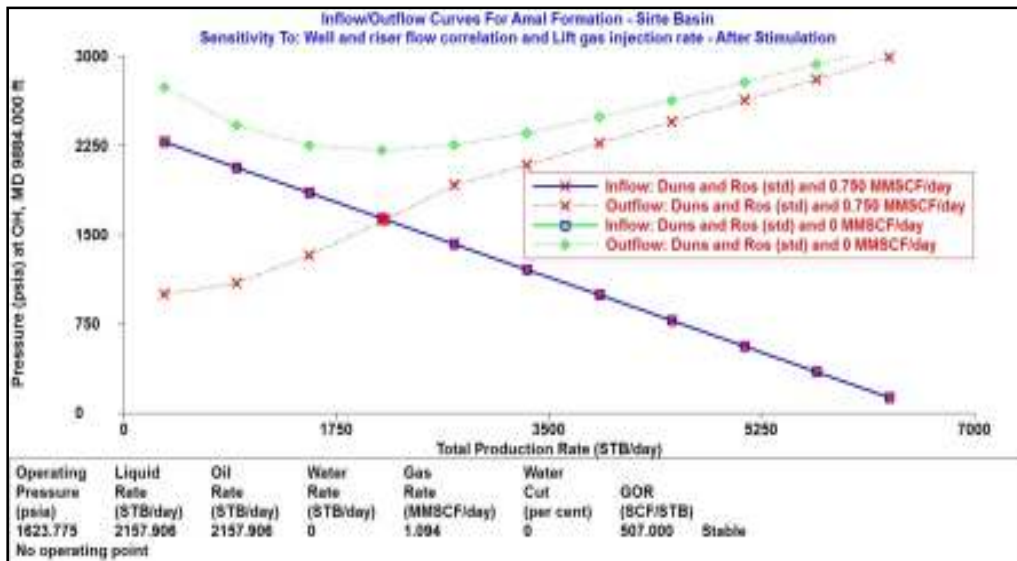


Figure 10: Inflow/Outflow curve stimulated

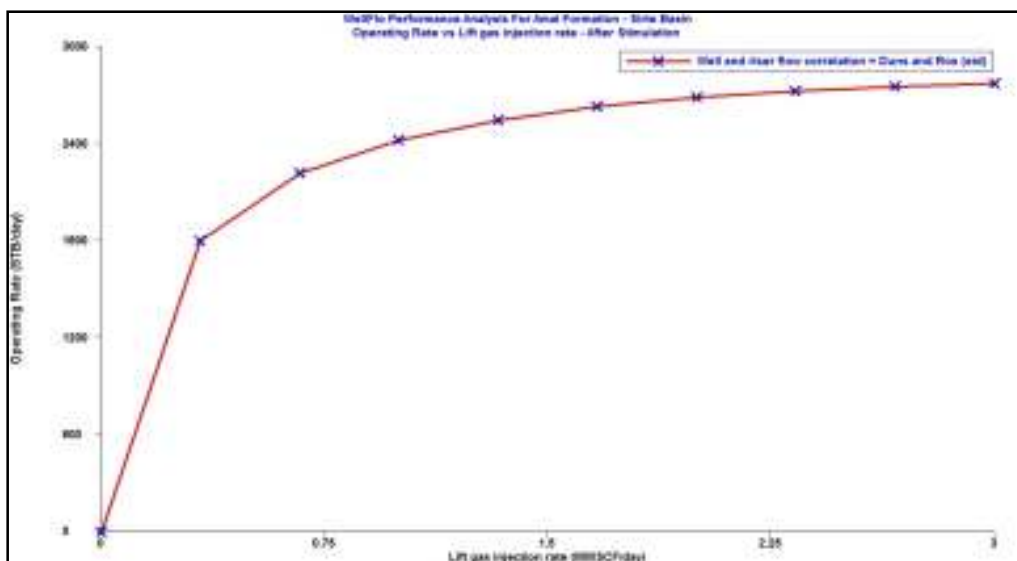


Figure 11: Lift gas injection rate after Acidizing

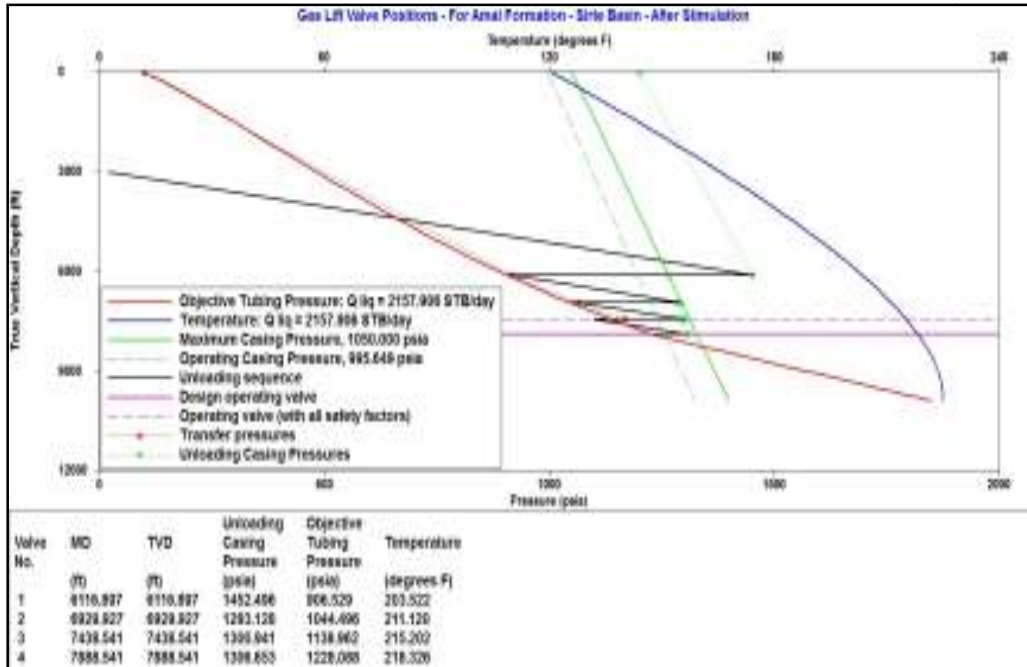


Figure 12: Gas lift positions after acidizing

6 ECONOMIC IMPACT

Based on production history, a comparison between two cases: with and without stimulation treatment. As depicted in figure 11, production forecasting was estimated for the case without treatment based on 3 years production with a decline rate of 5%; on the other hand, production prediction of the treated case was estimated based on more than 3 years production after treatment with decline rate of 10%. A significant increase in production indicating that treatment was fit to purpose technically.

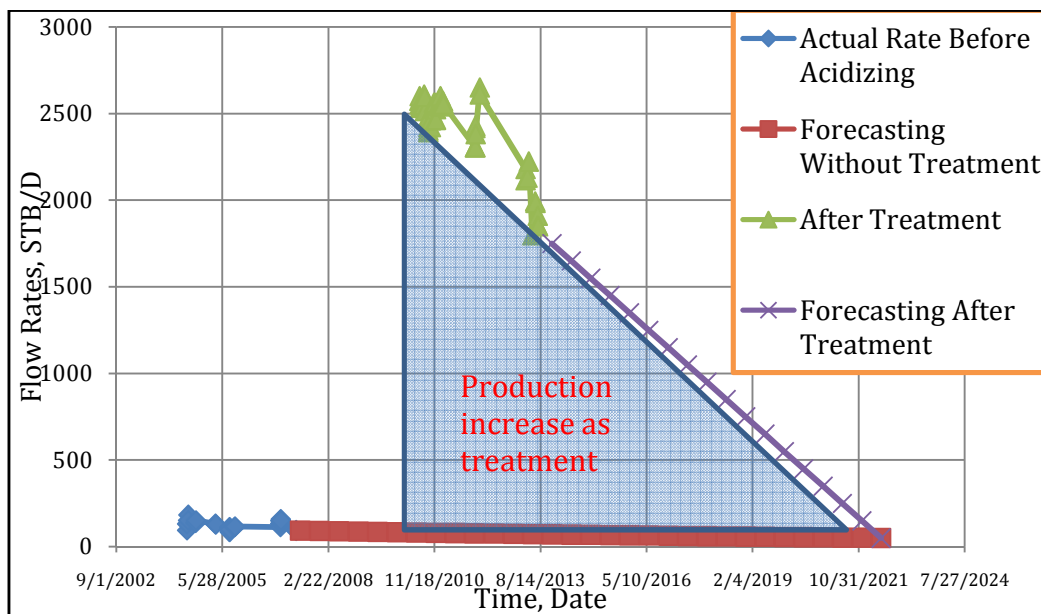


Figure 13: A comparison between treated and untreated cases with forecasting.

Furthermore, an economic analysis was performed in order to evaluate economics 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 taken.

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 station was 25,000 bopd where 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 \$m	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

7 CONCLUSION

The result of the modification of Amal Formation meant lowering near well-bore pressure losses, lowering skin and an improvement in well productivity.

There were two factors that cause reduction in pressure drop:

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

Stimulation of Amal 'B' was to remove the skin damage near the well bore and to improve well influx (productivity) into well bore vicinity; this can be achieved by a 15% HCL acid with Halliburton additives and Guidon as diversion system.

After treatment the Production increased by a ratio 299.4% by optimum gas injection rate 0.75 MMSCF/Day and fluid level increased by a ratio 57.1% which was much greater than Unstimulated. Therefore, this raises the importance of investigating the potential production increase and the treatment cost efficiency for this formation when carrying out stimulation campaign in order to rank in terms of stimulation preference.

During designing an acid job, engineers must be aware of a variety of formation damage that can occur. There were certain steps should be followed to avoid that. The most common types of formation damage caused during acidizing as formation de-consolidation, fines mobilization, reaction by-products, chemical incompatibilities, precipitation of iron compounds, emulsions and sludge.

345 The criteria used to choose the optimum injection rate was basically called the technical optimum
346 injection rate. However, the economic optimum gas injection rate will be relatively low. It was
347 denoted as the gas injection rate at which the marginal cost of providing extra injection gas was equal
348 to the marginal revenue of the extra well production gained from the extra gas
349 incremental. Nevertheless, Down-hole sampling, PVT, special core analysis were required to have a
350 better vision and design. Moreover, for fine tuning a good reservoir and geological description like
351 bed thicknesses, faults, fractures, rock type, geometry and structure through extra seismic acquisition
352 were very powerful.
353

354 **COMPETING INTERESTS**

355 Authors have declared that no competing interests exist.
356

357 **ABBREVIATIONS**

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

398

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