A GEOLOGICAL EVALUATION OF ACID-STIMULATED WELLS IN THE GREATER TONGONAN GEOTHERMAL FIELD

R. A. Medrano, Jr. and F. G. Delfin, Jr.

PNOC-Energy Development Corporation (PNOC EDC), Fort Bonifacio, Metro Manila, Philippines

Abstract

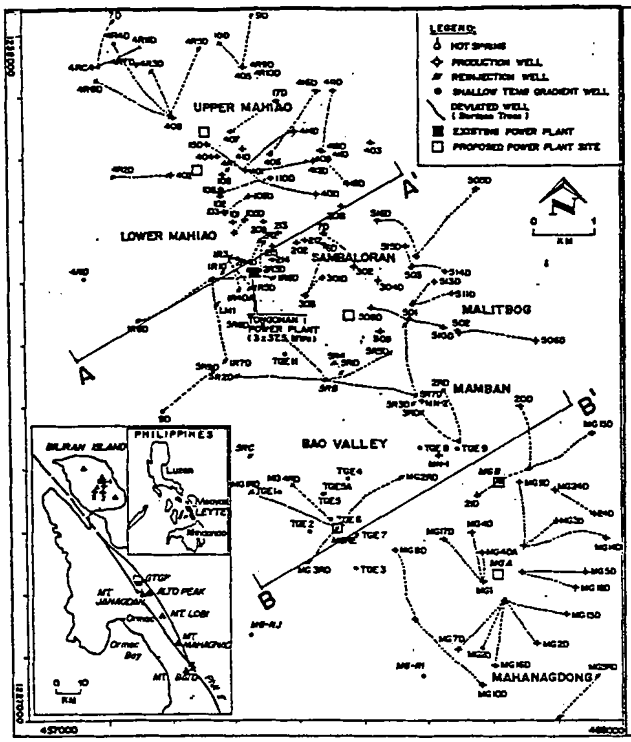
Correlation of borehole geology with results of acid-stimulation of 10 wells in the Greater Tongonan geothermal field was conducted to determine if the wells's responses to acidizing are related to specific geological parameters. The acidized wells were selected based on confirmed mud damage (109D, IIOD, MG-7RD), reduced well capacity due to silica deposition (2R4D, 5R7D), and inherent poor permeability (4R6D, IRIO, MN-1, MG-8D, MG-10D). The results of the acid-stimulation indicated that the mud-damaged wells generally showed the largest improvement as measured by the absolute increase in injectivity index before and after acidizing; the wells clogged by silica deposits showed moderate improvement while the inherently tight wells displayed minimal improvement,

The improvement in the wells could not be positively correlated to specific operational parameters such as the volume of acid used, the aggregate thickness of the acidized zones, and the pump pressure employed. Our correlation also showed that such geological features as the temperature, dominant alteration type, and even abundance of calcite veins in the acidized payzone do not exert any significant role in determining improvement in well permeability during acid-stimulation. The geological parameter that has a direct influence on the acidizing results is the lithology of the acidized payzone. Wells whose payzones occur within the Mahanagdong Claystone invariably displayed little or no improvement confirming the inherent tightness of this formation. Those wells whose acidized zones occur within the Mamban Formation and Mahiao Sedimentary Complex displayed variable improvements but are generally more improved compared with those wells within the Mahanagdong Claystone. Another factor that appears to pre-determine success in acid-stimulation is the presence of total circulation losses in the payzone. Wells whose acidized zones have associated total drilling circulation losses displayed better improvement as a group compared with those without associated total losses of circulation in the acidized zones. Only well 109D displayed results that are somewhat inconsistent with the general trend.

Because inherently tight wells respond poorly to acidizing, it is recommended that future acidizing jobs be concentrated on mud-damaged and mineral-clogged wells. The target payzones of these wells should be hosted by either the Mamban Formation or by the Mahiao Sedimentary Complex and must have associated total drilling circulation losses. Lastly, because our study is site-specific, its applicability to other geothermal fields needs to be independently validated.

1.0 INTRODUCTION

In order to enhance production and injection capacities in the Greater Tongonan Geothermal Field (GTGF), Leyte, Philippines (Figure 1), PNOC-EDC undertook acid-stimulation of several wells suspected to be damaged by drilling mud brine deposits, or to be inherently impermeable (Buning et al., 1995). The purpose of this study is to determine if the responses of the wells to acid-treatment can be correlated with borehole geology. Such correlation, if established, can aid in setting criteria for the judicious selection of wells in future "acidizing" operations. Our study, which basically extends Buning et al.'s evaluation to include geological parameters. assumes that the equipment and techniques employed during the operations were adequate and appropriate. Furthermore, the results of the acidizing operations which we use in this study are taken largely from Buning et al. (1993) supplemented by internal PNOC EDC reports.



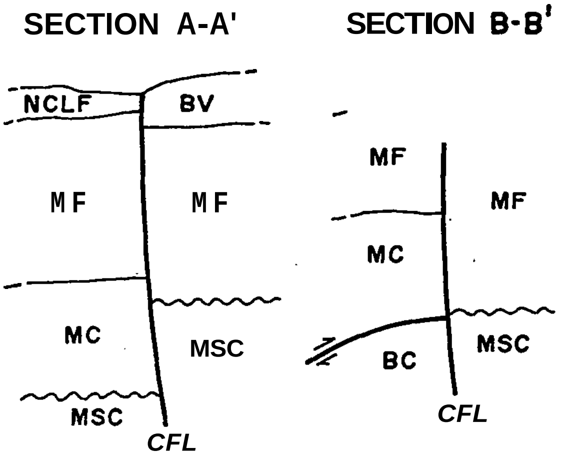


Fig. 1. Location Map of GTGF:

Fig. 2. Schematic stratigraphic sections along lines A-A' and B-B.

2.0 OUTLINE OF THE GEOLOGY OF GREATER TONGONAN

The GTGF, like most geothermal systems in central Leyte (Fig. 1), occur within a -55 km x 5 km fault-wedge of the left-lateral Philippine Fault (Tebar et al., 1991). Within this structural wedge, the Philippine Fault bifurcates into several interlacing branches. Over 100 wells drilled to depths reaching 2.7 km show that the GTGF is underlain mostly by arc volcanics and their sedimentary derivatives. A recent re-interpretation of the stratigraphy of the field (Fig. 2) made by Delfin et al. (1995) is summarized below .

The oldest rocks in the area, believed to be part of the Re-Tertiary Basement Complex (BC) of Leyte island, consist of massive serpentinites and chaotic mixtures of serpentinites, hornfels, schists, and gneisess with rare sedimentary inclusions. This assemblage has been encountered only by a few wells drilled west of the Central Fault Line CFL). East of the CFL, the wells bottomed in a massive clast-supported conglomerate/breccia, at least 1100-1400m thick, consisting of mega-boulders of microdiorites, quartz monzodiorites, and volcanics intercalated with some sandstone and claystone lenses termed the Mahiao Sedimentary Complex (MSC). The Early Miocene MSC is unconformably overlain by two different formations west and east of the CFL. The Mahanagdong Claystone (MC), an 880-1240 m-thick Late Miocene sequence of predominantly fine clastics overlies the MSC west of the CFL in the southern and western edges of the GTGF. East of the CFL, the MSC is unconformably overlain by the 550 to 1400m-thick Late Miocene-Early Pliocene Mamban Formation (MF) composed of altered pyroxene andesite lavas, tuff breccias, hyaloclastites with minor limestone and shaley units. Unconformably covering the Mamban and representing the surficial unit in most of the GTGF is the Late Pliocene to Pleistocene Bao Volcanics made up of fresh to slightly weathered and altered hornblende andesite lavas and breccias. Derivatives of the Bao Volcanics, mostly laharic breccias with intercalated tuffs deposited on the western margin of the GTGF, constitute the Late Pleistocene North Central Leyte Formation (NCLF).

Two separate hydrothermal convective systems occur in the GTGF. The first one, centered in the Upper Mahiao sector, has a maximum reservoir temperature of 320°C and contains neutral-pH two-phase fluids with maximum reservoir Cl contents of 10,000 ppm. This system upwells in the vicinity of 401 and 410 and ouflows mostly to the southeast. Wells drilled into this system derive permeability and production largely in the MSC-MF unconformity. The other system is located in the Mahanagdong sector and is separated from the Upper Mahiao system by the Mamban block (Fig. 1). The Mahanagdong reservoir is centered in MG-3D/MG-14D with maximum reservoir temperature of -310° C. The fluid is a two-phase brine containing about 4,000 ppm Cl, enthalpy of –1800 kJ/kg, and NCG of 3-5% (Parilla et al.. 1995). Unlike the Mahiao reservoir, permeability and production in Mahanagdong is controlled largely by fractures and not by the **MSC-MF** unconformity.

3.0 ACID-TREATMENT DESIGN AND METHODOLOGY

The design and conduct of the acid-treatment. operations performed by PNOC-EDC have been discussed by **Buning** et al. (1995) and are only briefly summarized here. Two general modes of acid-treatment were conducted: matrix acidizing and gelled acid fracturing.

Matrix acidizing was designed to chemically remove damaging materials in the wellbore or formation brought about by mineral deposition or the use of high-viscosity mud (HVM). The operation starts with the injection of a preflush solution of 10% HCl intended to dissolve iron and carbonate compounds which could later deposit insoluble minerals with the HF acid used in the mainflush. The volume of preflush is equivalent to 50 gal/ft of payzone for a 75 gal/ft mainflush dosing rate (Buning et al., 1995). The mainflush is a mixture of 10%HCl and 5% HF with the volume calculated to be 75 gal per foot of target payzone. The mainflush is immediately followed by a postflush of water. It is intended as a rinse of unspent acid in the wellbore. Its volume is estimated to be at least twice that of the acid mainflush.

Gelled acid preflush solution was used for three wells (MG8D, MG-10D, MN-1) out of the ten wells acidized. The gel additive, which is a viscosity enhancer and friction reducer, was intended to increase hydraulic efficiency. This gelled acid treatment technique was conceived to test the use of acid stimulation in wells with inherently low permeability with the aim of extending existing fracture networks intersected by wells and possibly create new fluid channels.

4.0 ACID-STIMULATED WELLS

The first acid-treatment in the GTGF was conducted in well 2R4D in 1993. Five wells (110D, 1R10, MG-10D, MG-8D, MN-I), were treated in 1994 and four (4R6D, 5R7D, 109D, MG-7RD) were treated in 1995.

Most of the wells were selected on the basis of confirmed mud damage or decline in production/injection capacities. Several wells, such as MG-8D. MG-10D, MN-1, were chosen to test if acid-treatment can improve the capacities of wells with low natural permeability Table **1 lists** the acid-stimulated wells in the GTGF, reason for their stimulation. method used, aggregate thickness of acidized zone. volume of acid used, and date of the acidizing operation.

'ABLE 1. LIST OF ACID-STIMULATED WELLS IN GRE TER TONGONAN GEOTHERMAL FIELD.

Well Name	Permeability Problem	Acid Job	Aggregate Thickness of Acidized Zone (m)	Volume of Acid Used (gals)	Date Acidized
2R4D	Silica deposition	Matrix	450	112.854	Dec.1993
110D	Mud damage	Matrix	400	98,831	Jan. 1994
lRlO	Low permeability	Matrix	175	43.428	May 1994
MG-8D	Low permeability	Gelled	150	36.960	June 1994
MG-10D	Low permeability	Gelled	150	36,918	July 1994
MN-1	Low permeability .	Gelled	150	36.036	Aug.1994
4R6D	Low permeability/Mud damage	Matrix	200	30.759	Aug.1995
5R7D	Low permeability/Silica deposit.	Matrix	200	30.759	Sept.1995
109D	Mud damage	Matrix	200	30.759	Nov. 1995
MG-7RD	Mud/cement damage	Matrix	200	30.759	Dec. 1995

Brief background information on the geology, drilling and utilization history of these wells are given below.

Well 2R4D is a reinjection well completed in October, 1981 to a total measured depth (MD) of 2176 m. It was put on-line into the Tongonan-I Fluid Collection and Disposal System (FCDS) in 1984 with a starting injection capacity of 85 kg/s. Silica deposition in the bore resulted to a decline in injection capacity to about 40 kg/s by August, 1988. A mechanical work-over operation to clear the blockages performed in 1990 brought the well's injection capacity to about 80 kg/s. Subsequent utilization, however, diminished this capacity to less than 20 kg/s by late 1992 (Buning et al., 1995).

Well 11OD was drilled to 1695 mMD and completed in May, 1993 to provide additional steam supply for the Tongonan I Plant. The well was put on-line into the Tongonan-1 FCDS in the same year with an output of 4.1 Mwe. The well's lower than expected output compared to its surrounding wells was attributed to the use of about 6,000 bbls of high viscosity mud (HVM) during drilling of its production interval.

Well IR10 (M-10) was drilled as a reinjection well for the disposal of effluents from the Tongonan I Plant. It was drilled and completed to a total depth of 1546m in January, 1978. Poor permeability, as indicated by the absence of circulation losses during drilling, low injectivity and high wellhead pressure during completion tests, did not allow the well to be hooked up into the FCDS. It was utilized, however, as a temporary injection well for discharge brine and sump fluids.

Wells MG-8D and MG-10D were drilled as delineation wells for the "Mahanagdong A" development. Both wells encountered low temperature and nil to minimal circulation losses during drilling. Completion tests confirmed the poor permeabihty of both wells as indicated by their low injectivity indices with high wellhead pressures. Hence, both wells remained on stand-by and acidizing was intended to increase their permeability with the aim of utilizing both as injection wells.

Well MN-1 was drilled vertically to a total depth of 2586 m and completed in November, 1979. It was designed as an exploratory well to test the production potential of the Mamban sector but the encountered temperature of –190°C indicated that this sector was unsuitable for power generation. Several circulation losses were experienced during drilling but surprisingly, it only had an injectivity index of 13.2 l/s-MPa at whp of 0.9 MPa after completion testing. The well was never utilized and remained on stand-by.

Well 4R6D was drilled to test the reinjection potential of the north-northwest portion of the Upper Mahiao sector and to augment the existing reinjection capacity of the Upper Mahiao-South Sambaloran power developments which are to start operation in mid-1996. It was completed in April, 1995 to a total measured depth of 2736m. The well encountered several drilling losses that range < 1-5.0 BPM but the overall permeability was low as shown by its injectivity index of 10.6 li/s-MPa at 2.93 MPa equivalent to a reinjection capacity of 23 kg/s.

Well 5R7D was originally intended as a production/delineation well (MB-7D) to test the southern boundary of the Malitbog sector, and the northwestern extent of the Mamban area. It was completed in April, 1981 and reached 2887 mMD. It was later renamed 507 and changed to 5R7D when it was decided to be used for reinjection due to low power output. The low permeability of the well contributed to this low output and the well was utilized for reinjection of brine during initial testing of the Malitbog wells.

Well 109D is a production well drilled for use in the Tongonan I steamfield It was initially programmed to be a deep deviation well drilled towards the northwest to extract production from a highly two-phase zone. Several circulation losses were encountered during drilling indicating good permeability. The well was TD'ed at 1306.65 mMD in December 1992 when it got stuck upon reaching this depth. Backoff operation was conducted and cleared the stuck pipe with the top of fish at 1013 mMD. The well was hooked-up to the power plant on April 9, 1993. In May. 1994 a blockage was discovered at 205 mMD. It was interpreted as a casing break in the $9^{5}/_{8}$" section after impression runs. A work-over operation was conducted in September, 1994 to repair and reline it with a 7" casing. During the work-over. a casing break was also detected on the $9^{5}/_{8}$" casing at 412 m. The damaged portion was repaired and cement squeezing was undertaken. After workover. the injectivity index was measured at 40 li/s-MPa.

Well MG-7RD is a deviated reinjection well drilled on the southeastern portion of the Mahanagdong sector. It was TD'ed in September, 1995 to a total depth of **1804** mMD. Geological indicators, drilling characteristics and completion tests indicated good permeability along Cabalonan-A fault. The well had an injectivity index of 18 l/s-MPa at vacuum condition translating to a reinjection capacity of 81 kg/s. In relation to adjacent wells, this capacity was considered low and mud damage was suspected to be the cause. In addition, cementing of the permeable zones from 1565-1629 mMD which had to be conducted to stabilize a collapsing formation during dnlling also contributed to the fair permeability measured in the well.

A summary of selected geological features of the wells is given in Table 2. These features include the formation and drilling losses encountered **by** the wells, the permeable zones **as** determined from completion tests, the temperature, dominant alteration mineral and abundance of vein calcite in the targetted payzones, and the **supposed** structures intersected **by** the boreholes.

5.0 RESULTS OF ACID-STIMULATION

The results of the acid-stimulation (Table 3) are measured in terms of increases in both injectivity index and well capacity before and after acidizing. In this study, we chose to measure the increases in terms of absolute values rather than the percentage increases in injectivitiy and well output used **by** Buning et al. (1995). Because the absence of whp is a qualitative indicator of substantial improvement in well permeabilty, the wells can be grouped into two broad groups according to the absence of wellhead pressure (whp) during injectivity tests immediately after acidizing. Furthermore, wells with injectivity indices at vacuum whp can be compared equally; comparison of improvement in wells that have significant whp is much less straightforward.

Those wells whch showed relatively good improvement as indicated by the absence of wellhead pressure during completion testing include 2R4D, 110D, MN-1, 5R7D, 109D, and MG-7RD. On the other hand wells 1R10, MG-8D, MG-10D and 4R6D showed little improvement after acidizing.

The results also show that gelled acidizing, whch used a viscosity enhancer and friction reducer for greater hydraulic efficiency, did not provide marked improvement compared to the matrix acidizing method in inherently impermeable wells (Table 3). This conclusion. however, is equivocal because the gelled acidizing technique implemented did not fully adhere to the original design of the method because of operational constraints.

In addition, the results show that the greatest improvement apparently took place in the mud-damaged wells followed by those damaged **by** silica deposits. Inherently impermeable wells show little or minimal improvements (Fig. 3). For the mud-damaged wells (110D, 109D, and MG-7RD), there is apparently no direct correlation between the degree of improvement and the volume of mud lost in the well (Fig. 4). This trend, however, is based on only three wells in the GTGF. Including the results of acidized well PN-32D, a muddamaged well in Palinpinon, supports the initial conclusion that the degree of improvement in mud-damaged wells is not related to the volume of drilling mud lost in the well.

ABLE *I* SUMMARY C SELECTED GEOLOGICAL FEATURES.

Well Name	Formation Encountered (mMD)	Drilling Losses (Type, Depth)	Permeable Zone From Completion Tests	Acid — Pay Zones (mMD)	Dominant Secondary Mineral/ Calcite Vein Abundance	Payzone Temp. (°C)	Fault Intercepts Depth (mMD)
2R4D	BV (0-70) MF (-70-1600) MSC (1600-2176)	PLC (1280) TLC (1580-2100)	1300-1550 (minor) 1700-1900 (major)	1300-1550 1700-1900	Epidote/	282 281-289	Malitbog (1500-2100)
110D	BV (0-80) MF (80- 1695)	TLC (901) PLC (1053-1135) PLC (1116-14834 TLC (1483)	1050-1100 (minor) 1500-1550 (minor) 1575-1600 (minor) 1692 (major)	1000-1200 1500-1700	Illite/. Weak to Mod.	264-288 304-308	Mahiao East Fault (818-884) Upper Mahiao Fault (866-1131) Litid South (1389-1587)
1R10	MF (0-1546)	None	850-900 (minor) 1000-1200 (minor) 1200-1250 (major) 1350-1450 (minor)	1175-1250 1350-1450	Illite-Smectite/ Weak	191-198 1%	N-S Mahiao (647-649)
MGID	BV (0-99) MF (99-1826) MC (1826-2713)	None	1942-2042 (minor) 2492-2542 (major)	2500-2650	Calcite/ Weak	274-284	Kabadyangan A (1872-2514) Kabadyangan B (2270-2514) Cambantog (2392-2542)
MG-8D	BV (0-96) MF (96-1287) MC (1287-2697)	PLC (1959-2006/) PLC (2083-2126/) PLC (2137-2169/)	1899-1999 2198-2298	1880-1930 2050-2150	Calcite/ Weak *to* Mod.	225-226 229-232	Cabalonan (1101-1367) Mahanagdong (1595-1653) TOW — (1901-2292) upper Paril (2048-2690) Paril (2663-2690)
MN-I	BV (0-150) MF (150-1750) MSC (1750-2586)	PLC (886-908) TLC (908-995) PLC (995-1020) PLC (2155-2164) PLC (2164-2586)	1700-1850 1900-2100	1700-1850	Quartz/ Weak to Mod.	189-192	Malitbog (1450-2050)
4R6D	BV (0-185) MF (185-1920) MC (1920-2736)	PLC (812-841) TLC (1905) PLC 1993-2003) PLC (2093-2096/) TLC (2096) PLC (2106-2115) TLC/PLC (2266-2267) TLC (2280) PLC (2281/4.0) PLC (2511-2520/) PLC (2269-2671) PLC (2608-2631)	950-1050 1950-2025	810-840 975-1025 1875-1925 2050-2100	Quartz/ Weak *to* Mod.	136-138 136-137 170-173 182-186	Rizal B (950-1086) Litid South (1741-2256) Abukayan (2669-2671)
5R7D	BV (0-1095) MF (1095-1818) MSC (1818-2887)	PLC (1896-1903/ PLC (2781)	1200-1300 2000-2100	1200-1250 1300-1350 1600-1650 2000-2150	Epidote/ Weak	225-237 240-244 265-266 238-241	NW Fault (1200-1300)
109D	BV (0-480) MF (480-1306)	PLC (504-509) TLC (541) PLC (575-677) TLC (941-951)	550-620 (major) 900-994 (minor)	500-600 900-1191	Quartz/ Moderate	253 154-194	Mahiao (505-665) Mahiao East (700-850) East Fault Line (735-950)
MG 7RD	BV (0-137) MF (137-1730) MSC (1730-1804)	PLC (1486-1849) PLC (1489-1662/) TLC (1662)	1225-1300 1650-1750 1800-1804	1250-1300 1625-1750 1776-1804	Quartz/ Weak to Mod.	200-201 196-200 200-201 202	Cabalonan A (1486-1804/)

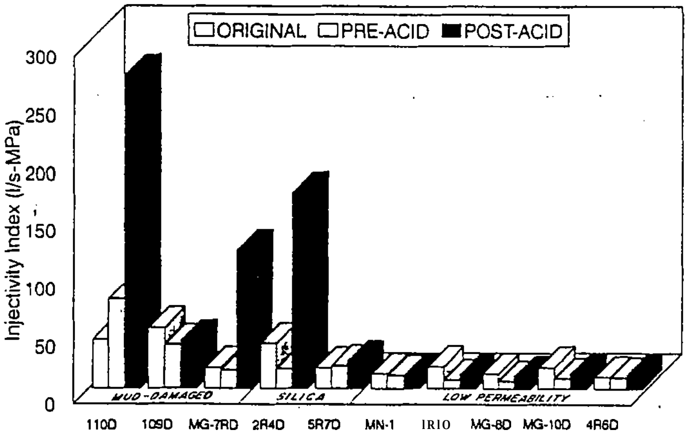


Fig. 3. **Results of** acid-stimulation

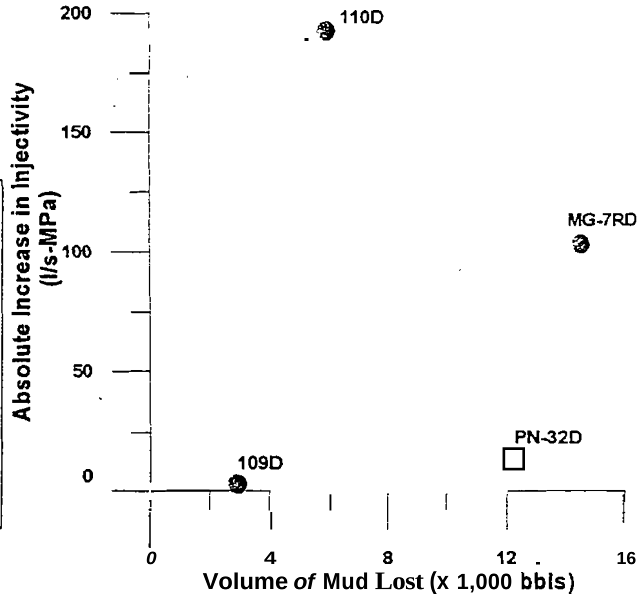


Fig. 4. Increase in injectivity index of muddamaged wells vs. volume of drilling mud lost

TABLE 3. RESULTS OF ACID STIMULATION

Well Name	Injectivity Index (li/s-MPa)[1]				Production *(MWe)* / Reinjection Capacity (kg/s)			
	Original	Pre-Acid	Port-Acid	Increase	Original	Pre-Acid	Post Acid	Increase
:	39	17.6	170	152.4	`90	18	182	164
110D	42	77.2	270.5	193.3	*Non-comml.*	*Non-comml.*	*12.4* *whp = 0.95 - 1* *wh = 0.95 - 1*	*12.4*
1R10	19.3 whp = 2.4	7.8 whp = 5.5 - 7	11.8 whp = 4.1 - 8	4	35	30 whp = 2.9	wh = 2.9	
MG-8D	13.1 whp = 5.2	6.8 whp = 2.7 - 5.4	11.2 whp = 1 - 4.4	4.4	-	10 whp = 4.2	22 whp = 4.2	12
MG-10D	19.1 whp = 8.2	9.0 whp = 3.9-7.2	13.0 whp = 4.7- 7.5	4	*Non-comml.*	*Non-comml.*	*Non-comml.*	-
MN-1	13.2 whp = 0.9	11.7	11.7	0	7 whp = 0.7	20 whp = 0.7	50 whp = 0.7	30
4R6D	10.6 whp = 2.9	10 whp = 0 - 2.8	12 whp = 0 - 1.6	2	23 whp = 1.2	25 whp = 1.2	38 whp = 1.5	13
5R7D	18	20	23.7	3.7	36	80 whp = 0.7	102 whp = 0.7	22
109D	52.5	38	41	3	*2.3* *whp = 0.68*	-	*6.75* *whp = 0.68*	*4.45*
MG-7RD	18	16	120	104	81	81	370	289

[1] Injectivity index is in liters/seconds-Megapascals at the corresponding wellhead pressure (whp). Unit of whp is Megapasc^{-1}, vacuum where none is shown.

6.0 DISCUSSION

In order to determine whether the results of the acidizing program in the GTGF were actually controlled by certain operational parameters, we plotted the results against the volume of acid used **(Fig. 5)** and the payzone thickness (Fig. 6). These two parameters were arbitrarily chosen to represent operational parameters largely because they are easy to quantify. Figure 5 indicates that there is no direct correlation behveen the volume of acid used **and** increases in well permeability. Wells MG-7RD, 5R7D, 109D and 4R6D whch used the Same volume of acid about. 31,000 gallons. displayed varying improvement in injectivities. Wells 2R4D and 110D. which consumed the greatest amount of acid displayed the largest

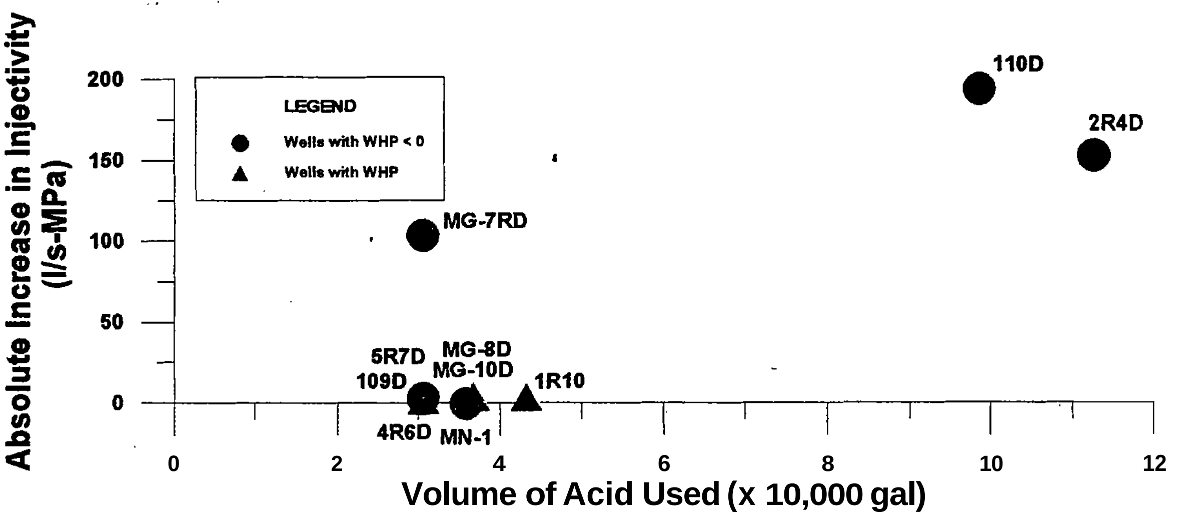


Fig. 5. Increase in injectivity index vs. volume of acid used.

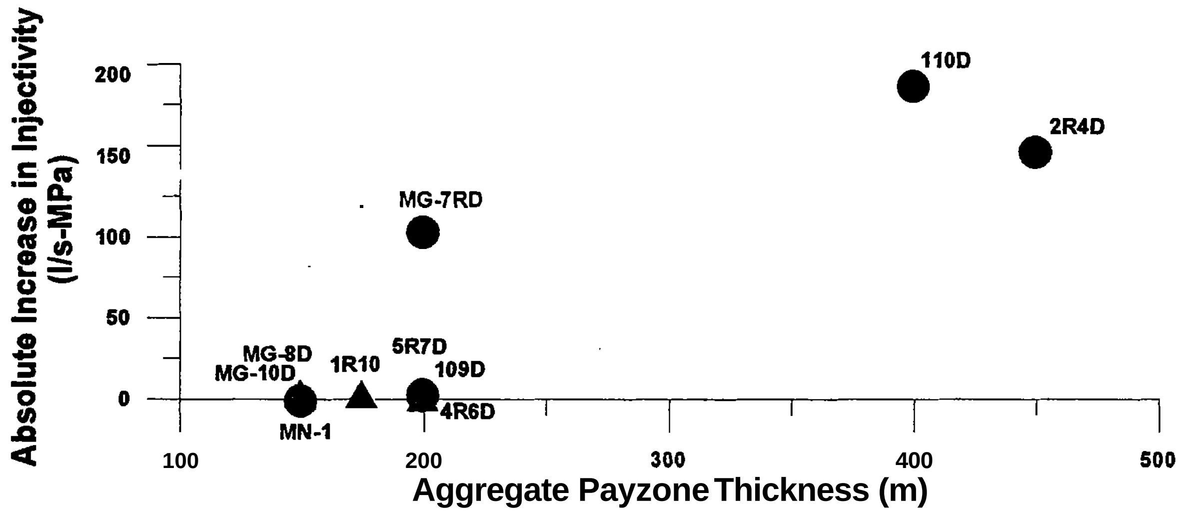


Fig. 6. Increase in injectivity index vs. payzone thickness.

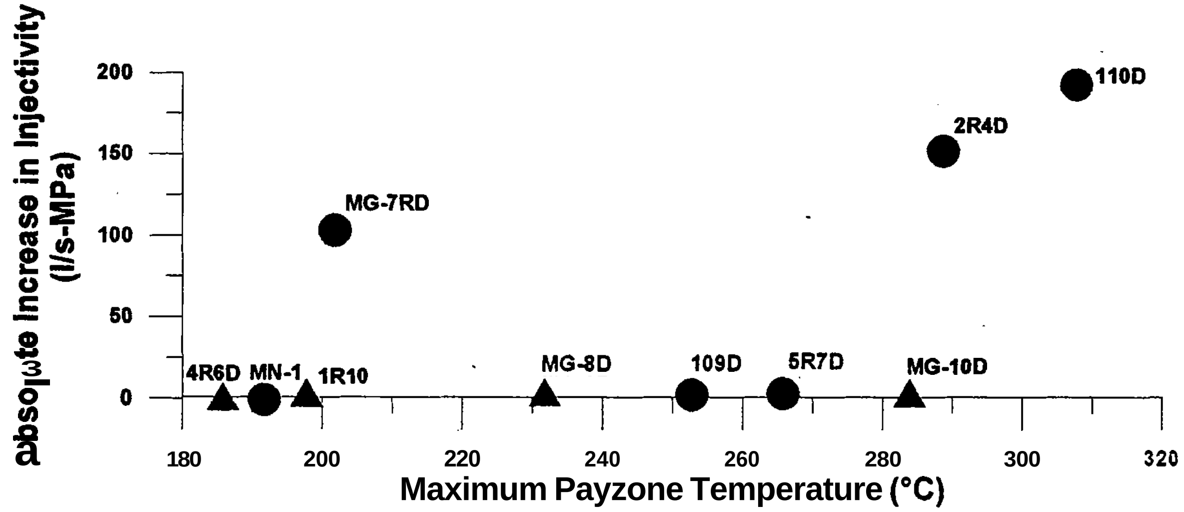


Fig. 7. Increase in injectivity index vs. maximum payzone temperature

improvement but their correlation is significantly not one-to-one. The aggregate thickness of the acidized payzone (Fig. 6), likewise, does not appear to exert a major control on the wells' improvement. For instance, wells 5R7D, 109D, MG-7RD and 4R6D again display varying improvements despite similar thickness (200 m) of the acidized payzone. Although not shown, the pump pressure applied during the acidizing operation also does not appear to have any direct correlation on the magnitude of improvement. Thus, improvements in the boreholes can be tentatively concluded to be unrelated to most operational parameters.

We plotted certain geological and reservoir features to ascertain if these could be factors in determining a well's chances of improvement in acid-stimulation. Figure 7, a plot of the maximum payzone temperature vs increase in injectivity, demonstrates that temperature has no control on permeability improvement. Although 2R4D and llOD which showed the largest improvement also have the highest temperature, majority of the wells clearly show that temperature of the acidized payzone does not have any bearing on the increases in injectivity. For example, wells 1R10, MG-8D and MG-10D wluch show almost the same increases in injectivity (Table 3 and Fig, 3) have varying maximum payzone temperature: 198°C for 1R10, 232°C for MG-8D, and 284°C for MG-10D.

The abundance of calcite veins as well as the dominant alteration mineral in the payzone also do not have any significant control on the acidizing results. The non-correlation of calcite vein abundance with well improvement (Fig. 8) is somewhat surprising considering that calcite is readily acid soluble. Even in inherently impermeable wells where calcite vein dissolution may be expected to yield significant improvement., the results indicate that vein abundance does not matter. Perhaps, this is an artifact of the small absolute difference in actual volume between weak (<5%) and moderate (10%) vein abundance and the small volume occupied by the veins with respect to the total payzone volume. Alternatively, the plotted vein abundance might not reflect the true in-situ amount as some veins might not have been recovered particularly in wells where the acidizied payzone where dnlled blind.

Like calcite vein abundance, the composition of the dominant secondary alteration (i.e. replacement) mineral in the payzone (Fig. 9) exert little effect on well improvement. For instance. epidote is the major alteration product in both 2R4D which showed the largest improvement as well as in 5R7D which is among the least improved by acid-stimulation. The results of wells with quartz as the dominant alteration mineral likewise varies, ranging from substantial improvement in MG-7RD to no improvement in MN-1.

The effect of payzone formation on well improvement is analyzed in Figures 10-11. Figure 10 clearly shows that all those wells with the Mahanagdong Claystone (MC) as the host payzone formation showed very poor improvement as indicated by the presence of whp and low absolute increases in injectivity index. . In comparison, the wells with vacuum mhp after acidizing are those with either the Mamban Formation (MF) or Mahiao Sedimentary Complex (MSC) as the host formation of the acidized zones. The absolute increases in injectivity indices in the latter group, however, shows considerable variation. The same general conclusions can be derived from Figure 11 (a variation of Fig. 10) which graphs the length and rock unit of the open hole against the corresponding injectivity increases. Wells with large absolute increases in injectivity, represented as steep lines in Figure 1la, have open-hole interval dominated by either MF or MSC. No wells with MC as the dominant formation in the open-hole interval yield large increases in injectivity. The "flat-liners'' or those with low absolute. injectivity values and with whp after acidizing are mostly those with the MC as the dominant unit in the open-hole (Fig. 1lb). Exception to this latter trend are MN-1 and 109D. Figure 11 also demonstrates that the length of the open-hole, not surprisingly, has no control on the resulting improvement in injectivity.

The varied response of wells with MF or MSC as the payzone or open-hole formation suggests that additional geological parameters in this group might be controlling their response to acid treatment. An obvious factor is the presence or number of supposed fault structures within the payzone depths. A quick look in Table 3 for 110D, 2R4D, MG-7RD, (substantial improvement) and 109D, 5R7D, and MN-1 (little improvement), however, Qspels this notion. Most of these wells have only one associated structure in the

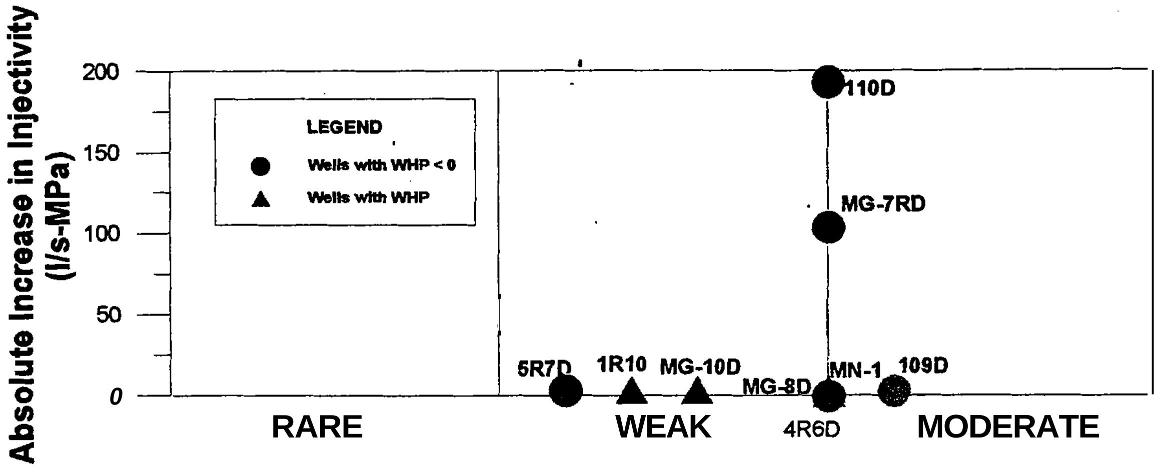


Fig. 8. Increase in injectivity index vs. abundance of calcite veins in payzone.

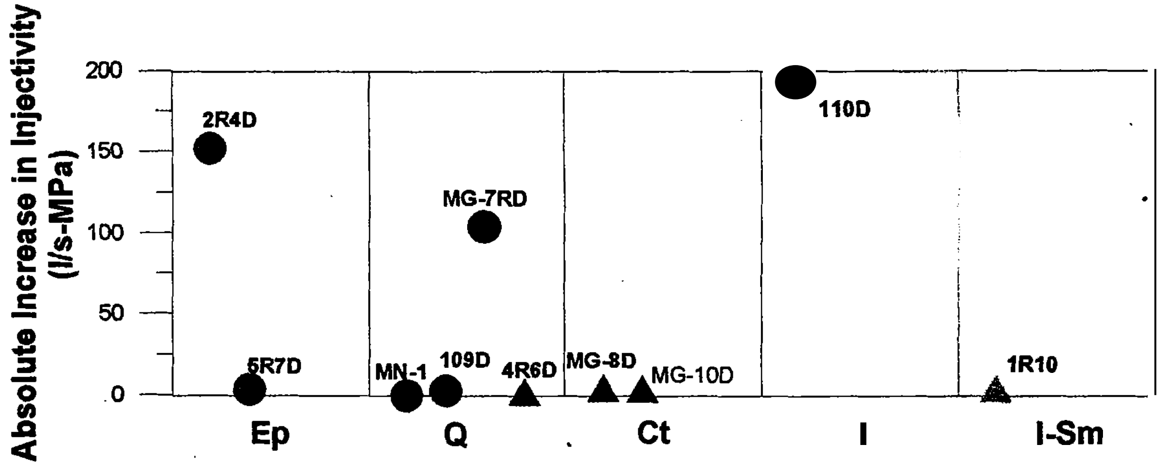


Fig. 9. Increase in injectivity index vs. dominant alteration mineral in payzone.

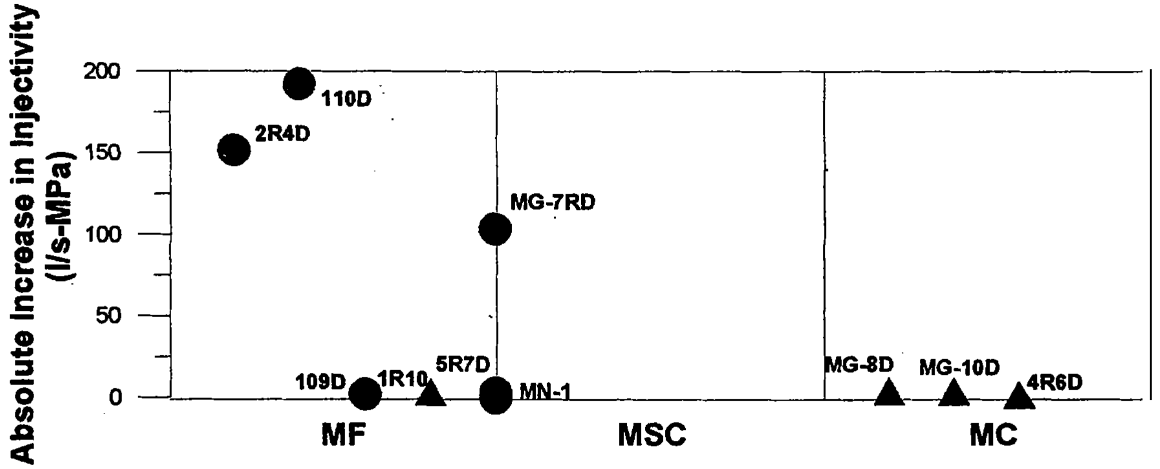


Fig. 10. increase in injectivity index vs. payzone formation.

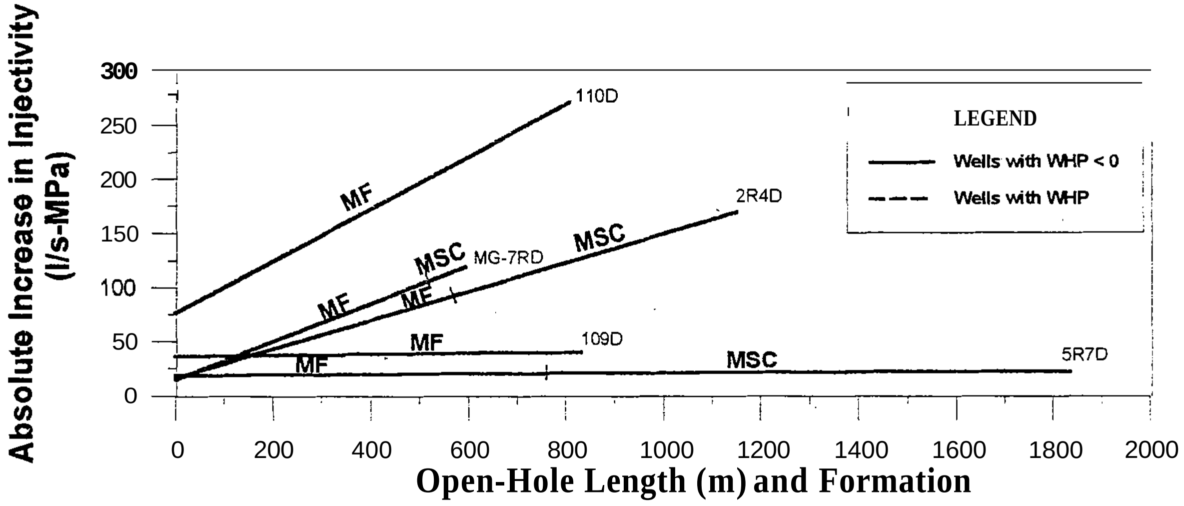


Fig. 11a. Increase in injectivity index vs. length and formation of open-hole.

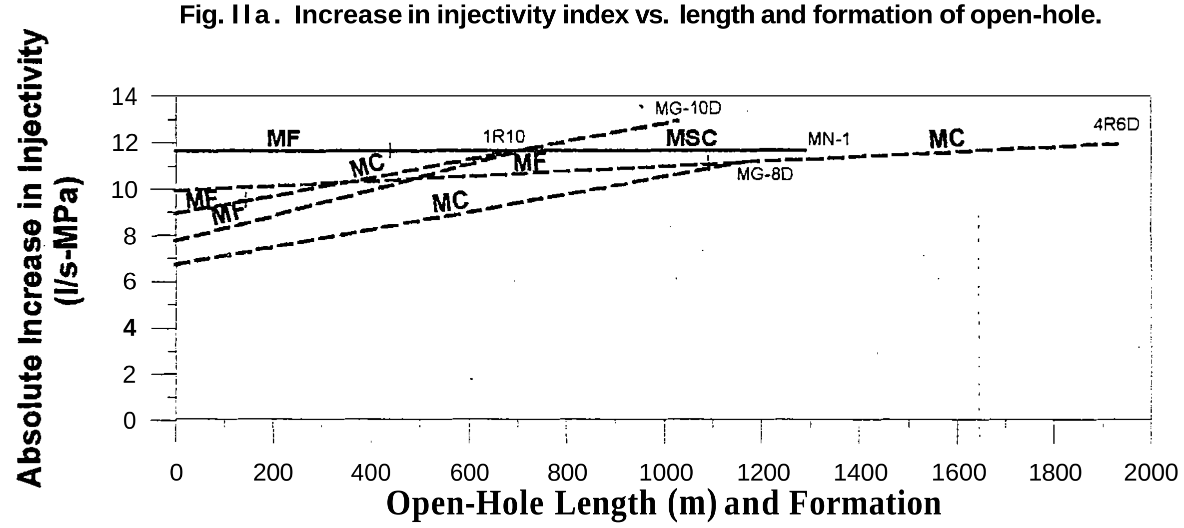


Fig. 11b. Increase in injectivity index vs. length and formation of open-hole.

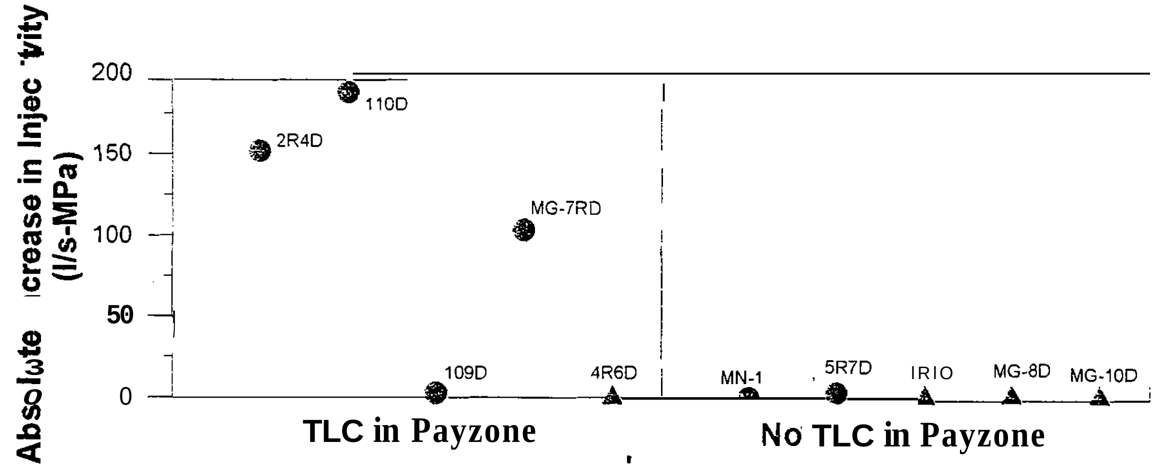


Fig. 12. Increase in injectivity index vs. occurrence of TLC in payzone.

acidized payzone yet display widely varying improvements. A further indication in Table 3 that the number of structures in the payzone do not contribute to well improvement is demonstrated by MG-8D and MG-10D whose payzones are cut by supposedly numerous faults but are among the least improved. Rather than the presence or number of supposed faults, it appears that the Occurrence of total circulation losses coincident with the acidized zones have a greater influence in dictating acidizing success. Figure 12 shows that those without associated total drilling losses in the acidized zones as a group have little improvement after acidizing compared with those whose payzones coincide with total loss of circulation (TLC) in drilling. Figure 12 also help explain the behavior of wells such as 5R7D and MN-1, whose payzone occur not in MC but in MF and MSC but still showed little improvement. The most plausible reason is that their payzone, despite being hosted by brittle rock units, have no associated inherent permeability as manifested by TLCs. Well 109D's response, as measured solely by the increase in injectivity, is the exception to this generally consistent rule and at present we can not determine why this is so.

7.0 CONCLUDING REMARKS

Our study, though far from exhaustive, has shown that certain geological factors help contribute to success in acidizing operations in the GTGF. Lithology and occurrence of TLCs in the payzone are key factors to consider in identifying and prioritizing wells for future acidizing jobs in the area. In contrast, operational and geological parameters such as acid volume, payzone thickness, temperature, abundance of calcite veins, dominant alteration mineralogy and number of supposed structures within the payzone have no apparent influence a well's chance of improvement through acidizing.

Our study further argues for future acid jobs to be concentrated in wells damaged by mud or by mineral deposition and whose payzones are hosted by either MF or MSC and are coincident with TLCs. The minimal to nil improvement in inherently tight wells, those with the MC as the host payzone formation, suggests that acidizing is not the proper way to enhance permeability in these wells. Perhaps, other methods like extended hydrofracturing might be the more appropriate technique. In addition, the results confirm that the MC is an inherently impermeable unit that should be avoided in the open-hole by future wells.

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