LITHOLOGY AS A GUIDE TO SAN ANDRES STIMULATION

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INTRODUCTION

A San Andres Task Force Group was initiated by Halliburton Services in January 1972, with the primary objective being to improve production stimulation results for the San Andres formation of the Permian Basin. A scientific approach was envisioned to combine lithology with engineering, laboratory and field date to determine the best type of treatment for San Andres wells. This study was divided into three parts.

Phase I of this project was an organizational and data-gathering phase.

Phase II was primarily a data and sample analysis phase. During this period, data and information were analyzed to define variations in rock type for one particular geographical area. The objective was to determine if a relationship could be found between depositional environment and rock type. Methods for determining basic rock type were to be investigated in this phase of the San Andres formation study.

The purpose of Phase III was to make a study of the results of various types of stimulation treatments for the different rock types in the San Andres formation. The purpose of this study was to determine if certain types of treatment might be more effective for a specific rock type. If this were true, the best general type of stimulation for a particular area producing from the San Andres formation might be selected once the rock-type of the formation had been determined.

DEPOSITIONAL ENVIRONMENT FOR THE SAN ANDRES FORMATION

At the time of San Andres deposition, seas covered the area and formed reefs of organic origin and built banks or barriers as shown in Fig. 1.

These barriers restricted the high energy wave action to some distance offshore. Behind or shelfward from these banks, the environment was that of quiet water with normal marine salinity adjacent to the barriers. In the shallow water near the shoreline, evaporation effects were greater, salinity increased and deposition near the shore was generally a fine-grained mud with an average particle size less than 10 microns. These fine particles resulted in a carbonate formation which for purposes of identification in this research is classified as Lagoon-Type Rock.

The slightly coarser particles deposited between the Lagoon and Reef or Bank barrier resulted in a rock known as Backreef Type Rock.

DEPOSITIONAL ENVIRONMENT CROSS-SECTION

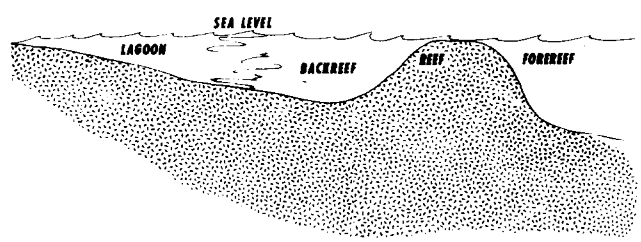


FIG. 1

The Reef-banks, skeletal or oolite facies, were formed by sand-size particles, deposited in the zone of highest energy or maximum turbulence. These Reef-banks later formed high porosity rock called Reef Type Rock. The deep water or basin area in front of the Reef is designated as the Forereef in Fig. 1.

The three primary depositional environments from a production standpoint are Reef (Bank), Backreef (Backbank) and Lagoonal, with the latter being the least significant. For future references, the three basic rock types resulting from these environments are classified as: Lagoon Type Rock, Rackreef Type Rock and Reef Type Rock.

GEOLOGICAL DESCRIPTION OF PERMIAN BASIN

The important San Andres reservoirs and the major geological structures of the Permian Basin area are shown on the map on Fig. 2. The reservoirs are divided into two classes, those producing from the upper San Andres and those from the lower San Andres member. The upper San Andres reservoirs are primarily confined to the southern part of the basin, along the edges of the sub-basins. The lower member is best developed along the northern part of the Midland Basin.

The San Andres formation is distributed from the Fort Stockton Anticline of northern Pecos County through central Crane, Ector, Andrews, Gaines, Yoakum and Hockley Counties. Producing fields extend west from Cochran County, Texas through northern Lea and southern Roosevelt Counties to Chavez County, New Mexico and south to central Eddy and Lea Counties, New Mexico.

The northernmost producing field is the Littlefield Field in southern Lamb County, Texas. Directly southwest are the Levelland, Slaughter and Wasson Fields. Along the Northwestern Shelf are the Lovington and Vacuum Fields extending into some scattered small fields and westward to Artesia. The Hobbs Field is best developed in the San Simon Channel.

FIG. 2—SAN ANDRES FIELDS IN THE PERMIAN BASIN AREA

In the northern part of the central Basin Platform are the Monument, part of the Hobbs and the East Hobbs Fields. The Seminole and West Seminole Fields are carbonate banks existing on structural highs surrounded by channels. In the eastern part of the central Basin Platform are some prolific fields, including the Dunes, Penwell, Goldsmith and Means. Fields shown in the Midland Basin are the Cedar Lake, Welch and Corrigan. Fields along the Eastern Shelf include the Garza, Diamond M, Coleman Ranch, Snyder and Howard-Glasscock.

The Slaughter Pool is one of the major reservoirs of the northern Permian Basin, with the best part of this field lying along the northern Permian Basin.

The San Andres, a formation of middle Permian Age, which is about 1400 feet thick, is divided into two members. The lower member includes the Glorieta clastic zone and the Holt dense zone at the base of the formation. In the more coarsely crystalline phase, it grades into a dark, finely crystalline, micritic dolomite of the lagoonal facies. The upper member of the formation is about 550 feet thick and is somewhat more finely crystalline and lighter in color than the lower member. The development of porosity in the San Andres, in general, depends upon the depositional facies and the environment in which the rock was originally formed.

LAGOONAL DEPOSITION

Where the seas covered the land in past geological times, the deposition between an offshore barrier and the land is usually referred to as a lagoonal deposit. This name stems from the fact that a quiet lagoon was formed between the reefs deposited in the high energy zone and the shoreline.

The San Andres deposition occurred during the Permian Period of the Paleozoic Era. At various stages of time, the seas apparently covered the Permian Basin extending over a very broad area into the Texas Panhandle and adjacent areas of Kansas and Oklahoma. Near the shoreline in the interior of platform and shelf areas where water salinity was high, there was very little organic growth and the carbonates deposited were very fine-grained. These sediments were low energy, micritic deposits with well-developed bedding.

In some places, minor amounts of anhydrite were deposited along with the fine debris of algae and fossils. They formed the major Lagoonal deposits. The anhydrite associated with Lagoonal depositional environment is replacement type and is porosity filling.

LAGOON ROCK TYPE

The Lagoon Type Rock characteristically has a very fine, intergranular porosity. The Lagoonal sediments usually have a particle size less than 10 microns resulting in formations with extremely low porosities and with permeabilities usually less than 0.01 md.

BACKREEF DEPOSITION

The Backreef sediments were deposited in a zone of slightly higher energy level than the Lagoonal deposits, resulting in a particle size generally ranging from about 10 microns to 250 microns. The Backreef deposition created intergranular porosity as well as porosity developed from shell fragments. The particle size, being coarser than Lagoonal deposition, resulted in a porosity development and permeability greater than those of Lagoonal deposition. The Backreef sediments were deposited in layers which are indicative of quiet water settling. Backreef deposition is characterized by anhydrite within the pore spaces. In the interior of the platform and shelf areas where water salinity was high, there was little organic growth and the carbonates were very fine-grained. Algae debris and small amounts of fossils formed the bulk of the carbonate mud.

BACKREEF ROCK TYPE

The Backreef Rock type formed from the Backreef sediments, has intergranular porosity and fossil fragments. The rock exhibits medium-grain-size particles with bedding characteristics of low energy rock. Anhydrite is usually found in the pores.

REEF DEPOSITION

Along the edge of the Delaware and Midland Basins deep upwelling waters brought nutriments to the surface and developed banks of limestone-depositing organisms. These relict particles deposited in the high energy zones contained coarse, sand-size grains usually larger than 100 microns. These Reefs contained oolites, skeletal remains, pisolites and fossil fragments. The Reef-banks created interparticle porosity generally much higher than Lagoon or Backreef porosities.

REEF ROCK TYPE

The Reef Rock has a massive, nonbedded appearance indicative of high energy depositional environment. The anhydrite associated with this rock is not in the pore spaces, but in nodules. The Reef Rock has a granular, sucrosic appearance with intergranular porosity, generally greater than that of other rock types in the San Andres formation.

ROCK TYPE VERSUS POROSITY

In addition to correlation of depositional and chemical characteristics, porosity was used in the identification of the three basic, predominant rock types. A porosity-rock type correlation was developed as a result of a thorough evaluation of electrical logs and core samples.

ROCK TYPE VERSUS FLUID-LOSS CONTROL

Laboratory tests were conducted to determine how fluid loss varied for three basic rock types (Table 1). Results shown indicate fluid-loss additives, in general, are not required for the Lagoon Rock Type.

Tests on Backreef cores indicated 0-25 lb fluid loss additive per 1000 gal. were required for gelled water and crude oil; however, fluid leak-off for acid was more severe. Generally, about 50-200 lb fluid loss additive per 1000 gal. were required for hydrochloric acid solutions.

C_w value is defined from the following equation:

$$C_w = 0.0164 \left(\frac{m}{a}\right)$$

Where:

C_w = fluid loss coefficient-wall building, ft/min$^{1/2}$

m = slope of plot of fluid loss versus $\sqrt{\text{time, min.}}$

a = cross-sectional area of core test plug

The spurt loss is the instantaneous fluid loss or initial loss with units of gallons of fluid per square foot of fracture area.

About 25-50 lb fluid loss additive per 1000 gal. were needed to control fluid loss of gelled water or crude oil through the Reef cores. A minimum of 200 lb fluid loss additive per 1000 gal. was required for good control of acid solutions.

TABLE 1—FLUID LOSS TESTS—SAN ANDRES CORES

Temperature: 100°F
ΔP = 1000 psig

Permeability, Liquid (md.)	Fluid Type	Additive (lb/1000 gal.)	Spurt Loss (gal./ft²)	C_w Value (ft/min^½)
	Rock Type: Lagoon			
<0.1	15% HCl Acid	None	0	No flow
<0.1	28% HCl Acid	None	0	Break through 7 min.
<0.1	28% HCl Acid	25	0	No flow
	Rock Type: Backreef			
1.03	San Andres Crude	25	0	0.000346
2.98	Gelled 1% KCl Water	25	0	No flow
0.4	15% HCl Acid	50	0.017	0.006
1.6	28% HCl Acid	200	0	0.0026
1.7	Emulsion (step 1)	None	0	No flow
1.7	15% HCl Acid (step 2)	100	0	0.0009
1.3	Highly Viscous Gel (step 1)	25	0	0.001
1.3	15% HCl Acid (step 2)	100	0.005	0.0009
	Rock Type: Reef			
4.74	San Andres Crude	50	0	0.000837
31.57	San Andres Crude	50	0.052	0.00322
18.37	Gelled 1% KCl Water	50	0	0.000708
9.90	15% HCl Acid	200	0.49	0.0068
9.90	28% HCl Acid	200	0.25	0.0065
9.90	Acid blend	200	0	0.0067
11.5	Emulsion (step 1)	None	0	0.00009
11.5	15% HCl Acid (step 2)	200	(No Control)	
11.5	Highly Viscous Gel (step 1)	25	0	0.0019
11.5	15% HCl Acid (step 2)	100	(No Control)	

NOTE: Step 2 was a second test continued on the same core as Step 1 using a different fluid as noted.

RELEASE OF FORMATION FINES

Acid reaction tests indicated that the release of excessive amounts of fines occurred with Reef and Backreef cores (Table 2). Table 3 shows the acid solubility of the Wasson Field cores used. X-ray diffraction analysis was used to identify the released fines (Table 4). These data indicate that larger amounts of quartz, feldspars and anhydrite were released from the Backreef cores than from the Reef and Lagoon cores. Larger quantities of clays were released from the Lagoon cores. The release of these insolubles, in addition to other fines, can cause plugging and permeability damage in the created fracture and the formation. Special fines-suspending acids have been developed to help overcome this problem when acid solutions are used for treating the San Andres formation. It should be noted that a larger quantity of fines was released from the Backreef cores than from the other two core types (Table 2).

TABLE 2—QUANTITY OF FINES RELEASED BY ACID SOLUTIONS

Wasson Field Cores

Type Acid	Quantity of Released Fines (lb/1000 gal. of Acid) Reef	Backreef	Lagoon
15% HCl	203.6	300.4	130.2
Acid blend	193.6	257.0	110.1
28% HCl	323.8	587.4	260.3

The above tests were run by placing an excess of core in 50 ml of the acid. After the acid was spent, the excess core was removed and the released fines were filtered from the solution. The fines were washed with acetone, dried and weighed.

TABLE 3—ACID SOLUBILITY OF CORES

Average Core Depth feet	Type Core	Average Porosity %	Average Permeability md.	Percent Solubility in 0.5 Normal HCl
5228	Reef	18.33	11.67	83.3
4750	Backreef	7.00	<0.10	74.5
5067	Lagoon	4.00	<0.01	72.7

TABLE 4—X-RAY OF ACID RELEASED FINES

Backreef

	15% HCl	28% HCl	Acid blend
Quartz	major	large	major
Feldspars	moderate-large	moderate	moderate
Calcite	-	-	-
Dolomite	moderate-large	-	moderate-large
Kaolinite	-	-	-
Montmorillonite	-	-	-
Mixed Layer Clay	very small	very small	small
Anhydrite	large	major	large
Gypsum	small	-	-
Illite	-	-	-

Lagoon

	15% HCl	28% HCl	Acid blend
Quartz	large	small-moderate	major
Feldspars	very small	-	small
Calcite	-	-	-
Dolomite	very small	small	small
Kaolinite	-	-	-
Montmorillonite	-	-	-
Mixed Layer Clay	small	small	small
Anhydrite	major	major	small
Gypsum	-	-	-
Illite	very small	very small	small

Reef

	15% HCl	28% HCl	Acid blend
Quartz	moderate	moderate	small-moderate
Feldspars	small	small	small
Calcite	-	-	-
Dolomite	moderate	moderate	moderate
Kaolinite	-	-	-
Montmorillonite	-	-	-
Mixed Layer Clay	-	-	small
Anhydrite	major	major	major
Gypsum	-	small	small
Illite	-	-	-

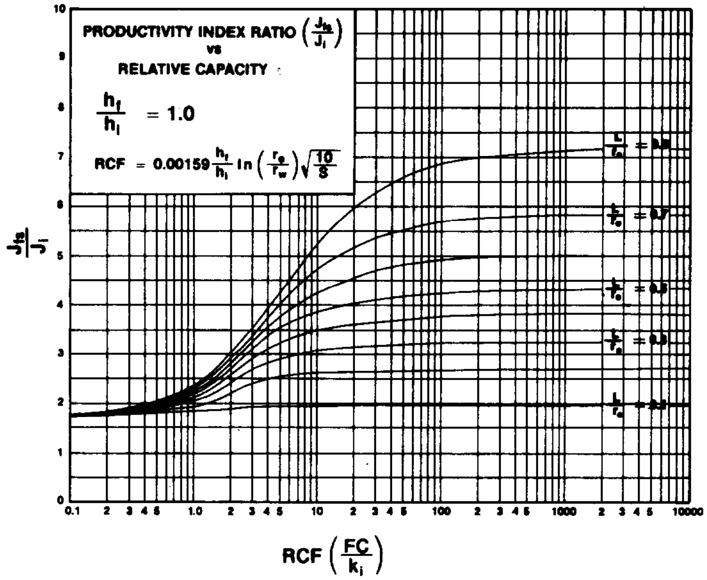
FRACTURE FLOW CAPACITY

Table 5 gives a comparison of fracture flow capacities (FC) obtained for Reef and Backreef cores using different sizes and concentrations of proppants. Acid-etched fracture flow capacities obtained without proppants, using various cores etched with three different solutions, are shown in Table 6.

The value of FC required for a good Productivity Index Ratio, whether obtained by fracturing with proppants or fracture-acidizing without proppants, is highly dependent upon the formation permeability. A Relative Capacity, RCF (FC/Ki), of about 10 to 200 is needed to obtain a Productivity Index Ratio, J_{fs}/J_i between 2-to-7 fold, excluding formation damage. This can be readily seen from Fig. 3.

In most cases, the use of acid solutions, without proppant, to remove wellbore damage is all that is required for successful stimulation of the San Andres Reef Rock Type formations. If fracturing with a proppant is used for stimulation, the use of a large proppant such as 10-20 or 8-12 sand should be beneficial in obtaining a desirable Relative Capacity and a resultant satisfactory Productivity Index Ratio.

If the formation is extremely tight as in the case of wells completed in predominantly Backreef depositional environment, high fracture flow capacity is not necessary to obtain a high permeability contrast between the fracture and the formation. In these cases, fracture length usually is more significant than permeability contrast. This can be shown by a study of the Productivity Index Ratio plot shown in Fig. 3.



Where:
J_i = Productivity index of unfractured system, bbl day^{-1} psi^{-1}

J_{fs} = Productivity index of fractured system, bbl day^{-1} psi^{-1}

$\frac{J_{fs}}{J_i}$ = Productivity index ratio, folds of increase

FC = Wk_f, fracture flow capacity, md-ft

k_i = Formation permeability (undamaged), md

h_f = Propped fracture height, ft

h_i = Formation thickness, ft

r_e = Radius of drainage, ft

r_w = Wellbore radius, ft

S = Well spacing, acres

RCF = Relative capacity factor as identified above in Fig. 3

$RCF\left(\frac{FC}{k_i}\right)$ = Relative capacity

L = Conductive fracture length, ft

FIG. 3

FIELD CASE HISTORIES

Table 7 shows the case histories of the results of both fracturing and acid treatments for the Backreef and Reef formations.

CONCLUSIONS

1. Based on this lithological study, porosity may be used as a general guide to assist in identifying depositional environment and rock types in the San Andres formation. Formations which exhibit Lagoonal depositional environment and characteristics generally have extremely low porosity. The Backreef Rock Type has medium porosity and the Reef Rock Type has a high porosity. This has proved to be valid in the Wasson and Slaughter-Levelland fields. Based upon the overall geology of the San Andres, a porosity lithology relationship similar to this should also exist in other San Andres Fields.
2. Field experience in the San Andres formation has indicated that a correlation exists between rock type and the most effective type of stimulation treatment for a given area or field.
3. Stimulation results indicate a controlled damage removal with acid containing a surfactant, and in some cases iron sequestering agents, is generally all that is required for treating the Reef Rock Type because of its high permeability associated with high porosity. Fines-suspending type acids have also been effective for removal of released fines in some cases.
4. Hydraulic fracturing has been successful in the Backreef Rock Type using water as the base fluid. Laboratory tests indicated the release of excessive quantities of fines when the Backreef cores were reacted with acid. If acid is used for stimulating the Backreef

Rock Type, a fines-suspending type acid should be most beneficial in preventing plugging and permeability reduction in the fracture, as well as in the formation. To date, fracturing with a proppant has been most successful in the Backreef zones.

5. Due to lack of field results, no definite conclusions can be made at this time regarding selection of the best stimulation method for the Lagoon Rock Type in the San Andres Formation. However, deep fracture penetration would theoretically be required due to the low formation permeability associated with low porosity. Extremely high conductivity is not usually necessary in this situation. At the present time, if natural fractures do not exist in the Lagoon Rock Type, it is not normally considered to be commercially productive.

TABLE 5—PROPPED FRACTURE FLOW CAPACITIES

Closure Pressure = 2500 psi

Proppant Concentration (lb/ft^2)	Fracture Flow Capacity, FC (md-ft) 20-40 Sand	10-20 Sand	8-12 Sand	12-20 UCAR® Pac
Reef Rock				
3.924	8506	28287	58225	ND
2.452	6130	18549	50502	ND
0.981	4855	14932	42180	ND
0.490	3506	8436	29246	15952
0.196	1451	3876	5087	52311
0.098	5677	14501	ND	47713
0.058	4110	15047	ND	31976
0.029	1028	1495	ND	697
Backreef Rock				
3.924	8330	30287	59922	ND
2.452	6666	22099	52749	ND
0.981	5304	18395	31401	ND
0.490	4110	14501	25509	ND
0.196	1610	5087	3879	ND
0.098	4958	2946	ND	ND
0.058	3061	19042	ND	ND
0.029	661	12086	ND	ND

ND = Not determined.

TABLE 6—ACID ETCHED FRACTURE FLOW CAPACITIES

Temperature = 100°F

Acid Solution	Contact Time (min.)	Closure Pressure (psi) 1732 / Fracture Flow Capacity, FC (md-ft) Reef	1583 Backreef	1693 Lagoon
15% HCl	20	108	2,588	516
	40	254	5,704	582
	60	556	6,218	648
28% HCl	20	196	4,136	1,426
	40	314	32,742	1,554
	60	614	67,198	1,426
Acid blend	20	154	2,068	542
	40	1,426	3,634	1,294
	60	5,178	7,270	2,338

NOTE: The acids were flowed across the simulated face of the core at 1000 psi and 100°F.
The fracture flow capacity values were obtained using a closure pressure of 0.33 psi per foot of depth.

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TABLE 7—FIELD CASE HISTORIES

Well No.	Rock Type	Fluid Type	Rate, BPM	Volume Gal. x 10^3	Sand, sks.	Production, BPD Before	Production, BPD After	Remarks
A	25% Reef 75% Backreef	Frac, gelled 1% KCl Water 25 lb F. L. A. per 1000 gallons	12	22.5	250 (10-20)	5 (oil) 18 (water)	28 (oil) 162 (water) (2 Mo. Later)	(Limited Entry, 32 foot Zone) 5.6 Fold Increase
B	Backreef	Viscous water gel	15	27.5	180 (20-40) 550 (10-20)	20 (oil) 0 (water)	45 (oil) 10 (water)	2.25 Fold Increase
C	Backreef	Frac, gelled water 25 lb F. L. A. per 1000 gallons	5	20.0	300 (20-40)	30 (oil) 9 (water)	52 (oil) 18 (water) (6 Mo. Later)	1.7 Fold Increase
D	Backreef	Frac, gelled 1% KCl water	8	10.0	29.8 (20-40)	71 (oil) 5 (water)	102 (oil) 32 (water) (1 Yr. Later)	1.44 Fold Increase
E	Backreef	Frac, gelled 1% KCl water	8	20.0	27.3 (20-40)	25 (oil) 4 (water)	156 (oil) 173 (water) (30 days) After 1 yr: 40 (oil) 80 (water)	6.24 Fold Increase
F	Backreef	Viscous emulsion pre-pad (20% HCl Acid)	4	10.5	-	90 (oil) 16 (water)	114 (oil) 31 (water) (After 1 yr.)	1.27 Fold Increase
G	Backreef	Viscous emulsion pre-pad (20% Fines Suspending Type Acid)	6.5	10.0	-	9.1 (oil) 3.9 (water)	35.1 (oil) 3.9 (water)	3.86 Fold Increase
H	Reef	Viscous emulsion pre-pad (15% HCl, Iron additives and surfactant)	-	2.0	None	0	1016 (oil)	-
O	Reef	15% Fines Suspending Type Acid	3.9	8.0	None	22 (oil) 6 (water)	54 (oil) 15 (water) (1 Yr. Later)	2.45 Fold
P	50% Backreef 50% Reef	Frac, gelled water	-	22.0	150 (20-40) 5 (10-20)	12 (oil) 0 (water)	174 (oil) 34 (water)	Holding up good after 5 months. 14.5 Fold Increase
Q	50% Backreef 50% Reef	15% Fines Suspending Type Acid	-	7.2	None	36 (oil) 36 (water)	40 (oil) 48 (water) After 7 mo.: 36 (oil) 44 (water)	Volume small-type treatment questionable
R	Backreef	20% Fines Suspending Type Acid	6.5	5.0	None	9.1 (oil) 3.9 (water)	35.1 (oil) 3.9 (water) After 4 mo.: 7.2 (oil) 10.8 (water)	Volume small-type treatment questionable
S	Backreef	Frac, gelled water	5.0	20.0	300 (20-40)	26 (oil) 6 (water)	113 (oil) 59 (water)	4.35 Fold
I	Reef	Viscous emulsion pre-pad (15% HCl, Iron additives and surfactant)	-	2.0	None	45 (oil) 855 (water)	836 (oil) (Not Given)	18.6 Fold Increase
J	Reef	Viscous emulsion pre-pad (15% HCl, Iron additives and surfactant)	-	1.0	None	30 (oil) 720 (water)	867 (oil) (Not Given)	28.9 Fold Increase
K	Backreef	15% Fines Suspending Type Acid	1.5	2.5	None	20 (oil) 200 (water)	33 (oil) 400 (water) (5 Mo. Later)	1.65 Fold Increase (Old Well)
L	Lagoon	15% Fines Suspending Type Acid	1.5	2.5	None	17 (oil) 3 (water)	No Results	Treatment unsuccessful
L	Lagoon (re-treatment)	Acid, 10,000 gal. emulsion pre-pad and 10,000 gal. 15% Acid	5.5	20.0	None	-	No Results	Treatment unsuccessful
M	Lagoon and Backreef	8,000 gal. pad 10,000 gal. 20% Fines Suspending Acid	4.75	18.0	None	5 (oil) 0 (water)	36.4 (oil) 15.6 (water) 4 Mo. Later: 2.0 (oil) 0 (water)	Treatment did not hold up
N	50-75% Reef 50-25% Backreef	Frac, gelled water	10.0	33.0	200 (20-40) 100 (10-20)	44 (oil) 22 (water)	183 (oil) 62 (water) Change lift Equipt: 308 (oil) 144 (water) (1 Yr. Later)	4.16 Fold; 7.0 Fold