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Connecting Laboratory and Field Results for Gelant Treatments in Naturally Fractured Production Wells

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Abstract

This paper demonstrates the connection between laboratory measurements and field results from gelant treatments in production wells at the naturally fractured Motatan field in Venezuela. Using a HPAM polymer with an organic crosslinker, laboratory corefloods revealed that under reservoir conditions, the gel provided oil and water residual resistance factors of 20 and 200, respectively. This gel was placed in several production wells in the Motatan field. In Well P-47, 1,000 bbl of this gel reduced the water cut from 97% to 64% and increased the oil production rate by 36%. The success of these treatments depends on the distance of gelant leakoff from the fracture face and the *in situ* residual resistance factors in the oil and water zones. Analyses were performed to determine these parameters, based on formation permeabilities, porosities, fluid saturations, fluid properties, fluid production rates, and pressure drops before, during, and after gelant placement. Accurate pressure drops before, during, and after gelant placement were particularly important. Sensitivity studies were performed to demonstrate their significance and the impact of measurement errors. A methodology is presented for optimizing the volume of gelant injected for these applications.

Introduction

For most gel treatments applied for conformance improvement and water shutoff, design procedures (especially the methods for treatment sizing) were strictly empirical—a fact that is partly responsible for the erratic success rates of these treatments. Many water shutoff treatments rely on the ability of polymers or gels to reduce permeability to water much more than that to oil. Unfortunately, the magnitude of this disproportionate permeability reduction cannot yet be predicted *a priori* under reservoir conditions. Since laboratory studies are rarely performed before field applications, widely varying field results are not surprising.

In some cases, individuals have suggested that field results with gelant treatments were at odds with laboratory data or with basic petroleum engineering principles. Depending on their background, operators, service companies, and researchers naturally place more credence in some observations than others. For example, a service company may prefer to emphasize certain field observations to rationalize an explanation that researchers find in contradiction with laboratory findings or in violation of established petroleum engineering principles. Consequently, all data (field, laboratory, and theoretical) should be considered when applying and evaluating field applications of gelant treatments. Of course, observations can be misinterpreted. Laboratory experiments may be botched or performed in misleading ways; theoretical or numerical studies may suffer from incorrect assumptions (e.g., garbage in/garbage out); and field results may be interpreted incorrectly. However, by combining sound laboratory, theoretical, and field observations, a consistent picture should emerge that can be used to improve the success rate for future field applications.

This paper describes an engineering-based approach to design and interpret gelant treatments in naturally fractured production wells. First, properties of the Motatan field are summarized, and laboratory and field results associated with the gelant treatments are reviewed. A mechanism of action is proposed for the gelant treatments. Field data are utilized to judge the heights and permeabilities of oil and water zones and the role of fractures in the excess water production problem. Analyses using gelant injection data provide valuable insight into the fracture area open to flow and the distance of gelant penetration from the fracture face. Post-treatment production results are used to estimate *in situ* oil and water residual resistance factors, which are compared with

laboratory values. Finally, the results are examined with regard to optimizing gelant volumes for future applications.

The Motatan Field

A detailed description of the Motatan field is provided in Ref. 1. The field is located in western Venezuela, southeast of Lake Maracaibo. The South Dome area of the field is an anticline with north-south elongation and is cut by numerous faults. The South Dome consists of four areas—two of which (P-35 and P-39) had high water cut wells that were treated with gelants. Each area produced from two reservoirs: the Pauji and Misoa formations, which are Eocene sandstones. Within these formations, the gelant treatments were targeted at three specific flow units, designated A9, A10, and B0. Depending on the well treated, the targeted sands existed at depths ranging from 7,930 to 9,000 ft and formation temperatures ranged from 210°F to 240°F. Water viscosity at these temperatures was about 0.25 cp. Gross pays ranged from 184 to 920 ft. Formation porosities were typically around 10%, while permeabilites were typically from 20 to 50 md. PVT analysis indicated an oil viscosity of 3.7 cp at reservoir conditions.

Exploitation of these naturally fractured, undersaturated reservoirs began in 1975. They were produced by water drive and rock-fluid expansion. Until the mid-1990s, the wells drilled in the P-35 and P-39 areas typically produced from 1,500 to 4,000 BOPD (per well) with very little water production. Subsequently, the water cuts rose steadily. At the time of the gelant treatments (1998-1999), the total production was 8,100 BOPD and 15,050 BWPD, yielding an average water cut of 65%. However, some of the wells had water cuts above 80%. (Production histories for the treated wells can be found in Ref. 1.)

The Gelant and Treatment Results

The gelant system was a high molecular weight, partially hydrolyzed polyacrylamide (HPAM) crosslinked with phenol and formaldehyde. Details of this gelant can be found in Refs. 2-4. In Berea sandstone at reservoir conditions, this gel provided a water residual resistance factor (F_{rrw}) around 200 and an oil residual resistance factor (F_{rro}) around 20.[1,3]

Gelant treatments were applied in four wells: P-43, P-47, P-48, and P-50. Descriptions of the gelant treatments and the production performance for the wells are available in Ref. 1. Table 1 summarizes the results. Significant reductions in water cut were observed in all treated wells. The mechanism of action that we envision for these treatments involves: (1) gelant injection with subsequent flow through the fracture system, accompanied by gelant leakoff through the fracture faces into both the oil and water zones, (2) shut-in to allow gel to form, and (3) return to production, with the gel substantially retarding water flow from the matrix into the fracture system but not significantly inhibiting oil flow.[5] The success of these treatments depends on the distance of gelant leakoff and the residual resistance factors in the oil and water zones.

This paper focuses on the results from Well P-47. The primary reason for this choice was that pressure data was recorded during critical parts of the treatments in this well. This pressure data is crucial for the proper interpretation of any gel treatment.

In Well P-47, the A9 and A10 flow units were treated with gelant. These sands were located at depths from 7,930 to 8,357 ft, with a net pay of 90 ft (distributed through six perforated intervals). The average rock matrix permeability and porosity of the net pay were 22 md and 9.8%, respectively. Shortly before the gel treatment, these sands produced 1,460 BWPD and 53 BOPD. The reservoir pressure was 2,600 psi and the pressure drawdown was 350 psi (i.e., between the reservoir and the well). The gelant treatment was applied during December 1999, when 1,000 bbl of gelant were injected at a rate of 1 barrel per minute (BPM). During gelant injection, the wellhead pressure ultimately rose to 3,500 psi. After gelant placement, the well was shut in for one week. Upon return to production, the intervals produced 63 BWPD and 87 BOPD, yielding a 42% water cut and a 64% increase in oil production rate. Four months later, the intervals produced 128 BWPD and 72 BOPD with a 1,300 psi drawdown, resulting in a 64% water cut. One year after the treatment, the production rates were 81 BWPD and 141 BOPD with a 465 psi drawdown.

Using Field Data to Estimate Flow Properties

Heights of Oil and Water Zones. Production data can be used to estimate some of the *in situ* flow properties within the reservoir. These parameters will ultimately be used in our assessment of the gelant treatment. The first parameters to be estimated are the heights of the oil and water zones, h_{oil} and h_{water}. In early 1994, Well P-47 produced 1,335 BOPD with a 2% water cut—the open zones experienced 98% fractional oil flow and were near the connate water saturation. In contrast, just before the gelant treatment in 1999, the well produced 1,460 BWPD and 53 BOPD. At this time, at least two possibilities existed. First, the entire open interval could have exhibited a uniform fractional water flow of 97%. If this case applied, a gelant treatment would not be effective because near wellbore treatments cannot alter the pseudo-steady state fractional flow of a single producing zone.[6] Alternatively, a small fraction of the original net pay may have continued to produce nearly 100% fractional oil flow, while most of the net pay was watered out. This scenario could be amenable to successful treatment using gelants.

Since the gelant treatments were ultimately found to reduce the water/oil ratio, distinct water and oil zones must exist within the net pay.[6] Assume that the total height (90 ft), completion, pressure drawdown, and degree of stimulation remained relatively unchanged between 1994 and 1999. Also, in examining the production data from the various wells, the total fluid production rates held reasonably constant over this same time period. With these assumptions, Eqs. 1 and 2 may be used to estimate the heights of the oil and water zones within the net pay at the time of the gelant treatment.

$$h_{oil1999} = h_{oil1994} \, [q_{oil1999}/q_{oil1994}] = 90[53/1,335] = 3.6 \text{ ft } ... (1)$$

$$h_{water1999} = h_{total} - h_{oil1999} = 90 - 3.6 = 86.4 \text{ ft} \dots\dots\dots\dots (2)$$

Thus, given a net pay of 90 ft, the heights associated with the oil and water zones before the gelant treatment were 3.6 ft and 86.4 ft, respectively. This determination allows for the possibility that multiple oil and water zones may exist (i.e., it does not assume that there is only one oil zone and one water zone). Also, the location of the oil zone(s) could be anywhere within the total pay.

k_w/k_o. With the above assumptions, the ratio of *in situ* endpoint permeabilities can be estimated from fluid production rates, viscosities (μ_o and μ_w), zone heights, and formation volume factors (B_o and B_w).[7]

$$k_w/k_o \approx [q_{water1999}\,\mu_w B_w\,h_{oil1994}]/[\,q_{oil1994}\,\mu_o B_o\,h_{water1999}] \dots (3)$$

Given that $q_{water1999}$=1,460 BWPD, $q_{oil1994}$=1,335 BOPD, μ_w=0.25 cp, μ_o=3.7 cp, B_w=1.0 reservoir bbl/stock tank bbl, B_o=1.2 reservoir bbl/stock tank bbl, $h_{oil1994}$=90 ft, and $h_{water1999}$=86.4 ft, the ratio of endpoint permeabilities, k_w/k_o, was calculated to be 0.064.

$$k_w/k_o \approx [1,460 \times 0.25 \times 1 \times 90]/[1,335 \times 3.7 \times 1.2 \times 86.4]=0.064 \dots (4)$$

For comparison, laboratory measurements on three field cores yielded k_{rw}/k_{ro} values of 0.167, 0.235, and 0.394. Also, for comparison, a k_{rw} value of 0.69 was assumed for a "unified simulation reservoir model" of the Motatan field. These comparisons suggest that caution is needed when selecting the relative permeability values. The field value of 0.064 seems to be the most appropriate for our purposes.

Was the Well Fractured? The calculations associated with Eqs. 1-4 do not depend on whether fractures intersected the well. The geological description for the Motatan field indicated that faults and natural fractures were present.[1] Productivity data can be used to confirm the presence of fractures. For Well P-47 before gelant injection, 1,513 BPD of total fluid were produced with a pressure drawdown of 350 psi. Thus, the productivity index, $q/\Delta p$, was 4.32 BPD/psi. Individual productivity indexes can be calculated for oil and water—i.e., 53 BOPD/350 psi = 0.151 BOPD/psi for oil and 1,460 BWPD/350 psi = 4.17 BWPD/psi for water. If flow were radial around the well (i.e., the well was not fractured), the measured productivity index should be less than or equal to that calculated using the Darcy equation for radial flow.[8]

$$q/\Delta p \le kh/[141.2\,\mu\,ln(\,r_e/r_w)] \dots\dots\dots\dots (5)$$

On the other hand, if the actual productivity index is significantly greater than the value calculated from the right side of Eq. 5, a fracture is probably present.[8]

For Well P-47, the wellbore radius, r_w, was 7 inches, and the external drainage radius, r_e, was assigned a value of 2,000 ft, based on the "unified simulation reservoir model" that was developed by PDVSA for this field. For oil production, the effective permeability to oil k_o, was assumed equal to the absolute permeability of the rock matrix—a value of 22 md. Given that h_{oil} was 3.6 ft and μ_o was 3.7 cp, the right side of Eq. 5 yields a value of 0.0186 BOPD/psi. This value was about one-eighth the actual productivity index for oil (0.151 BOPD/psi) and supports the supposition that a fracture intersects the wellbore. For water production, the effective permeability to water, k_w, was assumed equal to 0.064 k_o or 1.4 md (from Eq. 4). Given that h_{water} was 86.4 ft and μ_w was 0.25 cp, the right side of Eq. 5 yields a value of 0.42 BWPD/psi. This value was about one-tenth the actual productivity index for water (4.17 BWPD/psi) and confirmed the presence of a fracture.

Analyses During Gelant Injection
L_{pw}/L_{po}. During the process of gelant injection, the gelant flowed rapidly through the fracture system while leaking off some distance from the fracture faces in all permeable zones that were cut by the fracture. How much different was the distance of gelant leakoff in the water zone (L_{pw}) from that in the oil zone (L_{po})? The methods of Refs. 6 and 9 were applied to determine that the ratio, L_{pw}/L_{po}, was close to unity. Although the detailed calculations are not included here, the findings can be appreciated with the following arguments. First, the aqueous gelant experienced about the same residual oil saturation in the oil zone as in the water zone. The water zone originally had a high oil saturation but has become watered out. In contrast, the oil zone, of course, had a high oil saturation ahead of the gelant front. However, behind the viscous gelant front, the oil saturation was efficiently flooded to its residual level. Since the gelant experienced nearly the same oil saturation (i.e., S_{or}) in both the water and oil zones, the permeability to water was about the same in both zones (i.e., k_w=0.064k_o=1.4 md). Finally, the viscous gelant exhibited a very efficient (piston-like) displacement in both zones. Specifically, the mobility ratio was about 0.003 in both zones [i.e., (0.064/75 cp)/(1/3.7 cp) for gelant displacing oil in the oil zone and (0.064/75 cp)/(0.064/0.25 cp) for gelant displacing water in the water zone]. Thus, the gelant penetrated to nearly the same distance in the water zone as in the oil zone.

Estimation of Fracture Area. Additional useful information about the fracture system can be obtained during injection of the viscous gelant. During injection of 1,000 bbl of gelant[1] (HPAM crosslinked with phenol and formaldehyde) at a rate of 1 BPM, the wellhead pressure reached 3,500 psi. The hydrostatic head associated with the 8,000-ft fluid column was about 3,465 psi. Using standard methods, the pressure drop associated with friction down the pipe was judged to be small compared to the total pressure drop. Therefore, it was neglected in our analysis, and the estimated downhole pressure was about 6,965 psi. Nonetheless, downhole measurements would increase confidence in the parameters that will be calculated based on the downhole pressure.

Given that the reservoir pressure was 2,600 psi, the downhole pressure difference between the well and the formation was about 4,350 psi. The viscosity of the gelant was 75 cp at reservoir temperature (230°F) and 300 cp at room temperature. Some uncertainty exists about the downhole temperature during gelant injection; however, considering the depth and the volume of gelant injected, it was believed to be much closer to the reservoir temperature than to the wellhead temperature. This uncertainty points out the value of downhole measurements during gelant treatments. Consequently, wherever practical, we recommend that temperatures and pressure be measured downhole before, during, and after gelant placement.

In a naturally fractured reservoir, the fracture system is generally more complicated than in a two-wing hydraulic fracture. Instead of a planar fracture that is symmetric about the well, the fracture system may be branched, nonplanar, and asymmetric. Nevertheless, there is a certain fracture area, A_f, associated with the fracture system, regardless of its nature. (Of course, the open fracture area in a given system can change with conditions, such as with a change in wellbore pressure.)

As mentioned earlier, the actual productivity of Well P-47 was about eight times greater than that expected for radial flow through rock matrix in an unfractured well. Therefore, the flow capacity of the fracture system was substantially greater than that of the porous rock (at least, in the vicinity of the wellbore). Consequently, we assumed that the pressure drop through the fracture was negligible compared to that through the porous rock. For a short distance of gelant penetration from the fracture face in the water zone, the pressure drop across the gelant bank was approximately equal to the downhole pressure drop during gelant injection minus the downhole pressure drop during brine flow at the same rate. The downhole pressure drop during gelant injection (at 1 BPM or 1,440 BPD) was estimated at 4,350 psi. For a productivity index of 4.17 BPD/psi in the water zone, the pressure drop during brine flow at the same flow rate was about 350 psi (1,440 BPD ÷ 4.17 BPD/psi). Thus, the pressure drop across the gelant bank was approximately 4,000 psi (i.e., 4,350 psi minus 350 psi).

With the information provided above, the Darcy equation can be applied to estimate A_f/L_p, the ratio of fracture area to the average distance of gelant penetration from the fracture face.

$$A_f/L_p = (q/\Delta p)\, \mu_{gelant}/k_m \quad .... (6)$$

Given that q was 1,440 BPD, Δp was 4,000 psi, μ_{gelant} = 75 cp, and k_m = 1.4 md at S_{or}, A_f/L_p was 17,000 ft.

To solve for A_f and L_p, another relation is needed—i.e., that between the volume of gelant injected, V_{gelant}, and the distance of gelant penetration from the fracture face.

$$V_{gelant} = L_p\, A_f\, \phi\, (1\text{-}S_{or}) .... (7)$$

Combining Eqs. 6 and 7 leads to Eq. 8, which can be used to estimate the fracture length during gelant injection.

$$A_f = \{V_{gelant}\, q\, \mu_{gelant}\, /\, [\Delta p\, k_m\, \phi\, (1\text{-}S_{or})]\}^{0.5} .... (8)$$

Given a gelant volume of 1,000 bbl, a porosity of 0.098, k_m of 1.4 md, and S_{or} of 0.249, the fracture area, A_f, was about 36,000 ft^2 and the distance of gelant penetration from the fracture face, L_p, was 2.1 ft.

On first consideration, one might have expected a much larger fracture area than the calculated value of 36,000 ft^2. Given a fracture height of 90 ft and assuming that the fracture system consisted simply of two planar wings, the fracture length would be only 100 ft. In contrast, naturally fractured reservoirs are often envisioned as massive networks of interconnecting fractures, with a tremendous area associated with the fracture surfaces. However, our observation of a relatively low fracture area for Well P-47 is not inconsistent with a natural fracture system. The network of natural fractures near Well P-47 may have limited or no physical connection with other fractures or fracture systems in the reservoir. This idea is consistent with the production performance of the well. In particular, the water cut increased gradually over the course of six years from 1994 through 1999.[1] This result would not have been expected if the fractures were extensively connected throughout the reservoir. Instead, water would have channeled quickly and abruptly from the aquifer through the most conductive fractures into the production wells.

Sensitivity Studies. Sensitivity calculations were performed to examine the estimated fracture area and the distance of gelant leakoff. Of course, errors could enter the calculations for many of the input parameters, including pressure drops, flow rates, gelant viscosity, permeability, and porosity. Fig. 1 examines the impact of errors: considering combined parameter errors ranging from -50% to +50% of the base values (i.e., that led to A_f=36,000 ft^2 and L_p=2.1 ft). For example, a combined parameter error of –50% would result if Δp was assumed to be 2,000 psi instead of 4,000 psi, and all other parameters in Eq. 8 remained unchanged (i.e., V_{gelant}=1,000 bbl, q=1,440 BPD, μ_{gelant}=75 cp, ϕ=0.098, k_m=1.4 md, and S_{or}=0.249). Over the range considered in Fig. 1, the calculated fracture area varied from 29,000 to 51,000 ft^2 and the distance of gelant penetration varied from 1.5 to 2.6 ft. The calculated values appear to be reasonably tolerant of errors because the fracture area varies with the square root of the assorted input parameters (see Eq. 8).

After Gelant Placement
In Situ **Oil and Water Residual Resistance Factors**. Field results can be used to estimate the oil and water residual resistance factors that were exhibited by the gel after placement in the well. Equations relating *in situ* residual resistance factors to productivity indexes can be found in Refs.

5, 6, and 9. Eqs. 9 and 10 provide these relations for oil and water, respectively.

$$(q/\Delta p)_{oilafter}/(q/\Delta p)_{oilbefore} = 1/[1+(L_{po}/L_e)(F_{rro}-1)] \ldots\ldots (9)$$

$$(q/\Delta p)_{waterafter}/(q/\Delta p)_{waterbefore}=1/[1+(L_{pw}/L_e)(F_{rrw}-1)] \ldots (10)$$

Here, the before and after subscripts refer to oil or water productivity indexes before and after application of the gelant treatment. These equations are based on linear Darcy flow, and simply reflect how the productivity index in a given oil or water zone relates to the distance of gel penetration from the fracture face (L_{po} or L_{pw}) and the residual resistance factor (F_{rro} or F_{rrw}). The parameter, L_e, is provided from the Darcy equation for linear flow before the gelant treatment.

$$L_e = [k_w A_f /\mu_w] / [(q /\Delta p)_{waterbefore}] \ldots\ldots\ldots\ldots\ldots\ldots (11)$$

In Eq. 11, given that k_w was 1.4 md, A_f was 36,000 ft^2, μ_w was 0.25 cp, q was 1,460 BWPD, and Δp was 350 psi, L_e was calculated to be 55 ft.

As mentioned earlier, before the gelant treatment, the oil productivity, $(q/\Delta p)_{oilbefore}$, was 0.151 BOPD/psi, and the water productivity, $(q/\Delta p)_{waterbefore}$, was 4.17 BWPD/psi. Four months after the treatment, the oil productivity, $(q/\Delta p)_{oilafter}$, was 0.0554 BOPD/psi, and the water productivity, $(q/\Delta p)_{waterafter}$, was 0.0985 BWPD/psi. Given that $L_{po}=L_{pw}=2.1$ ft, and L_e=55 ft, Eqs. 9 and 10 indicate that F_{rro} was 46 while F_{rrw} was 1,080. The ratio, F_{rrw}/F_{rro}, was 23.5. These values were greater than those measured in the laboratory in Berea sandstone (F_{rro} = 20, F_{rrw} =200, and F_{rrw}/F_{rro}, =10).

Effect of Assumed Fracture Area. In the above calculations, the assumed fracture area (36,000 ft^2) was determined during gelant injection. One could argue that the fracture area open to flow during gelant injection was greater than that during production (either before or after gelant placement) because the downhole pressure was roughly 5,000 psi higher during gelant injection than during oil/water production. Fig. 2 examines the effects of assumed fracture area for the calculations associated with Eqs. 9-11. F_{rro}, F_{rrw}, and F_{rrw}/F_{rro} were determined for fracture areas ranging from 1,000 to 100,000 ft^2. Over much of the range investigated, F_{rrw}/F_{rro} was about 23. Thus, regardless of assumed fracture area, the *in situ* residual resistance factors differ to some extent from the laboratory values, where F_{rrw}/F_{rro} was about 10. This result is not surprising since the extent of the disproportionate permeability reduction varies with the character of the porous medium.[10]

We can adjust the assumed fracture area to achieve an *in situ* residual resistance factor that matched the value of either F_{rro} or F_{rrw} that was measured in the laboratory. For a fracture area of 15,200 ft^2, the *in situ* F_{rro} matched the laboratory value of 20, but the *in situ* F_{rrw} (457) was more than twice the lab value (200). On the other hand, for a fracture area of 6,640 ft^2,

the *in situ* F_{rrw} matched the laboratory F_{rrw} (200), but the *in situ* F_{rro} (9.3) was less than half the laboratory F_{rro}.

The above residual resistance factors were relevant four months after the gelant treatment was applied in Well P-47. Another set of calculations can be performed based on data collected one year after the treatment. In November 2000, the well produced 81 BWPD and 141 BOPD with a 465 psi drawdown. Therefore, productivity values were 0.174 BWPD/psi for water and 0.303 BOPD/psi for oil. The productivity for oil (coupled with Eqs. 9 and 11) suggests that F_{rro} at this time was near unity—indicating that the gel provided no significant resistance to flow in the oil zone. In contrast, the water productivity indicates that the gel continued to restrict water entry into the fracture—although somewhat less effectively than at four months after the treatment. For assumed fracture areas of 6,640, 15,200, and 36,000 ft^2, the calculated F_{rrw} values were 141, 322, and 761, respectively. These values are about 30% less than those at four months after the treatment. Thus, the gel experienced relatively little wash out from the water zone during the first year.

In summary, these calculations indicate the range of fracture areas and residual resistance factors that may be applicable. As discussed in the next section, the calculations are needed to optimize the volume of gelant treatments.

Optimizing Gelant Volume
Would the gelant treatment in Well P-47 have been more effective if a different volume of gelant was injected? Eqs. 7, 9, and 10 can be used to address this question. When using Eq. 7 to determine the distance of gelant penetration, A_f, must be assigned the value determined during gelant injection—36,000 ft^2 in this case. This assignment is mandatory in order for the predictions to match the actual water and oil productivity values associated with 1,000 bbl of gelant. The L_p values can then be calculated and used in Eqs. 9 and 10 to estimate post-treatment oil and water productivities as a function of gelant volume. Fig. 3 shows the results for the base case input parameters of 46 for F_{rro}, 1,080 for F_{rrw}, and 55 ft for L_e. This plot confirms the observed field result—i.e., the use of 1,000 bbl of gelant caused a 63% loss of oil productivity—from 0.151 to 0.0554 BOPD/psi.

The reader should note that a loss of oil productivity does not necessarily mean a loss of oil production rate. If the pressure drawdown is increased sufficiently, the oil production rate increases even though oil productivity decreases. This point may be better appreciated by considering Figs. 4 and 5. These figures translate Fig. 3 for the specific drawdowns of 1,300 psi (Fig. 4) and 500 psi (Fig. 5). As observed in the actual field application, a 1,000-bbl gelant treatment, coupled with a 1,300 psi post-treatment drawdown, resulted in a decrease in water production rate from 1,460 to 128 BWPD and an increase in oil production rate from 53 to 72 BOPD (Fig. 4), even though the oil productivity decreased by 63% (Fig. 3). In contrast, with a 500 psi post-treatment drawdown, the final oil production rate was 27 BOPD (Fig. 5) for the same 1,000-bbl gelant treatment.

Careful examination of Figs. 3 and 4 suggests that a more positive outcome may have resulted from using a smaller gelant volume in Well P-47. For example, Fig. 4 predicts that a 500-bbl gelant treatment would have resulted in the oil rate increasing to 105 BOPD while the water rate decreased from 1,460 to 248 BWPD. Compared to the results from the 1,000-bbl gelant treatment, the value of the extra 33 BOPD (i.e., 105 minus 72 BOPD) would easily offset the additional disposal cost for the extra 120 BWPD (i.e., 248 minus 128 BWPD).

Figs. 3-5 were generated using the set of input parameters where F_{rro}=46, F_{rrw}=1,080, and L_e=55 ft. This set of parameters assumed that the open fracture area was 36,000 ft^2. In the previous section, we investigated cases where the fracture areas *during production* were either 6,640 or 15,200 ft. For the case of 6,640 ft^2, Eqs. 9-11 yielded the set of parameters: F_{rro}=9.3, F_{rrw}=200, and L_e=10.1 ft. For the case of 15,200 ft^2, Eqs. 9-11 yielded the set of parameters: F_{rro}=20, F_{rrw}=457, and L_e=23.1 ft. If either of these sets of F_{rro}, F_{rrw}, and L_e values are entered into Eqs. 9 and 10 to generate figures like those in Figs. 3-5, the results will look virtually identical to Figs. 3-5. However, achieving this result requires that the L_p values from Eq. 7 must be calculated using A_f=36,000 ft^2.

As mentioned, consideration of Figs. 3-5 suggests that the treatment in Well P-47 may have shown a more desireable performance (at 4 months after the treatment) if a smaller gelant volume were used. However, this view must be balanced against a concern over washout of the gel. Field results one year after the treatment indicated that gel damage in the oil zone was diminished while residual resistance factors in the water zone decreased by 30%. Depending on the strength and stability of the gel, a smaller gel bank may have experienced more severe washout from the water zone.

In summary, Eqs. 7-11 and figures like those in Figs. 1-5 can be used to optimize the gelant volumes in field applications. These analyses may be especially valuable when utilizing the results from the first gelant treatment in a field to optimize subsequent treatments. PDVSA is also investigating the value of the analysis during sequential applications of gelant in the same well. Specifically, based on an analysis performed after injection of a first batch of gelant, a decision is made whether (and how much) gelant should be injected during a subsequent treatment in the same well.

Conclusions

This paper demonstrates the value of using basic calculations and relations between laboratory data and field observations for a gelant treatment in Well P-47 at the naturally fractured Motatan field in Venezuela. Some of the important conclusions from this work include the following:

1. Production data were used to estimate the relative permeabilities and heights of the oil and water zones.
2. Before gelant injection, the well productivity was about eight times greater than expected for radial flow—confirming the presence of fractures.
3. Pressure and rate data during gelant injection were instrumental in establishing the fracture area open to flow—estimated at 36,000 ft^2. Sensitivity studies demonstrated the effect of input errors and emphasized the importance of accurate downhole pressure measurements before, during, and after gelant placement.
4. The distance of gelant leakoff from the fracture face was about the same in the water and oil zones—about 2.1 ft.
5. Pressure and rate data collected during production four months after the gelant treatment were used to estimate *in situ* oil and water residual resistance factors—yielding values of 46 and 1,080, respectively. For comparison, laboratory values measured in Berea sandstone were 20 and 200, respectively.
6. Sensitivity analyses suggested that a more desireable oil productivity may have resulted from using a smaller gelant volume—e.g., 500 bbl rather than 1,000 bbl.
7. One year after the treatment, the water and oil productivity indexes indicated that the gel effectively resisted washout in the water zone but was largely destroyed or removed from the oil zone.

Nomenclature

A_f = fracture area, ft^2 [m^2]
B_o = oil formation volume factor, rb/stb [m^3/m^3]
B_w = water formation volume factor, rb/stb [m^3/m^3]
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor
h = height, ft [m]
h_f = fracture height, ft [m]
h_{oil} = height of the oil zone, ft [m]
h_{total} = total height of net pay, ft [m]
h_{water} = height of the water zone, ft [m]
k = permeability, darcys [μm^2]
k_f = fracture permeability, darcys [μm^2]
k_m = matrix permeability, darcys [μm^2]
k_o = permeability to oil, darcys [μm^2]
k_w = permeability to water, darcys [μm^2]
L_e = distance parameter defined by Eq. 11, ft [m]
L_f = fracture length, ft [m]
L_p = distance of gelant penetration, ft [m]
L_{po} = distance of gelant penetration in oil zone, ft [m]
L_{pw} = distance of gelant penetration in water zone, ft [m]
Δp = pressure difference, psi [kPa]
q = injection or production rate, BPD [m^3/d]
r_e = external drainage radius, ft [m]
r_w = wellbore radius, ft [m]
S_{or} = residual oil saturation
V_{gelant} = volume of gelant injected, ft^3 [m^3]
w_f = fracture width, ft [m]

ϕ = porosity

μ = viscosity, cp [Pa-s]

μ_{gelant} = gelant viscosity, cp [Pa-s]

μ_o = oil viscosity, cp [Pa-s]

μ_w = water viscosity, cp [Pa-s]

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SI Metric Conversion Factors

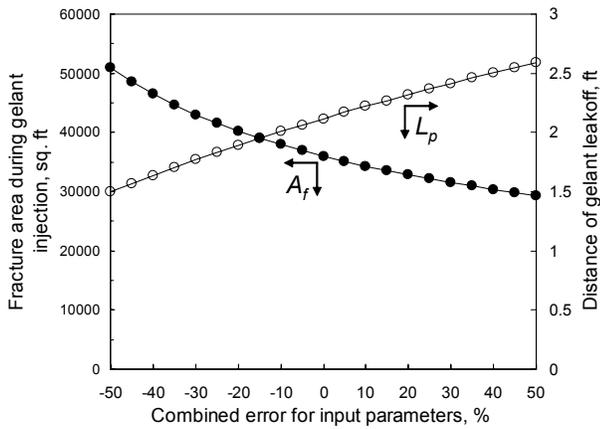|		
cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m
in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= μm^2
psi x 6.894 757	E+00	= kPa

*Conversion is exact.
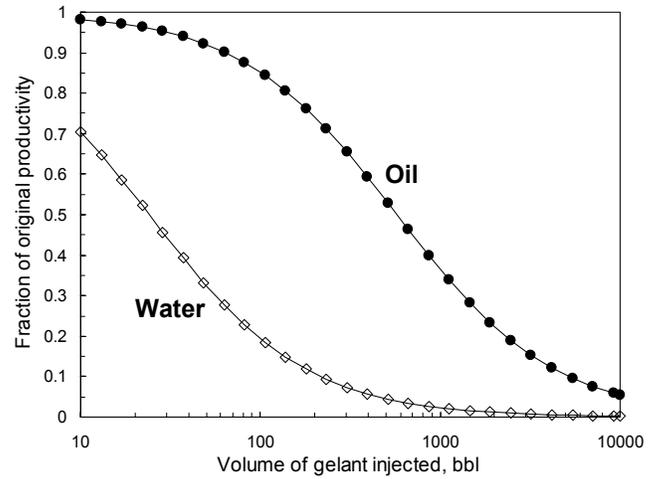
Table 1—Results from Four Gelant Treatments

| Well	Gelant volume, bbls	Water cut before gel, %	Water cut just after gel, %	Water cut a few months after gel, %
P-43	1,100	98	28	64
P-47	1,000	97	42	64
P-48	3,600	75	40	64
P-50	2,000	80	20	60

Fig. 1—Effect of errors on fracture area and gelant penetration calculations.
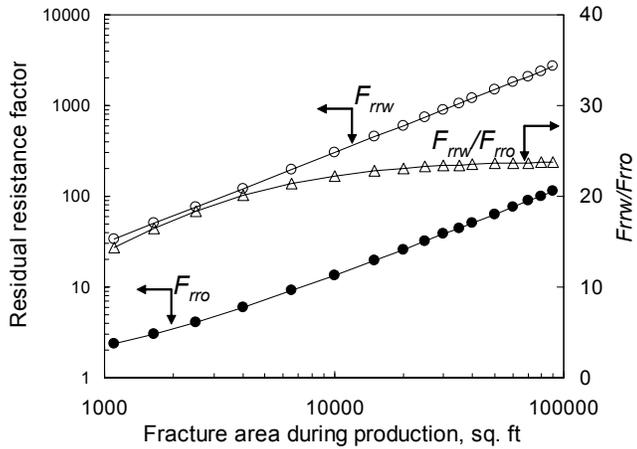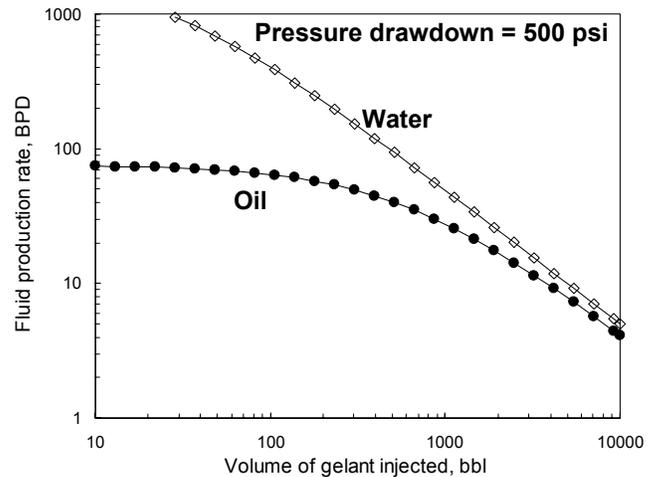

Fig. 2—Sensitivities for calculated *in situ* residual resistance factors.

Fig. 3—Effect of gelant volume on fluid productivities.
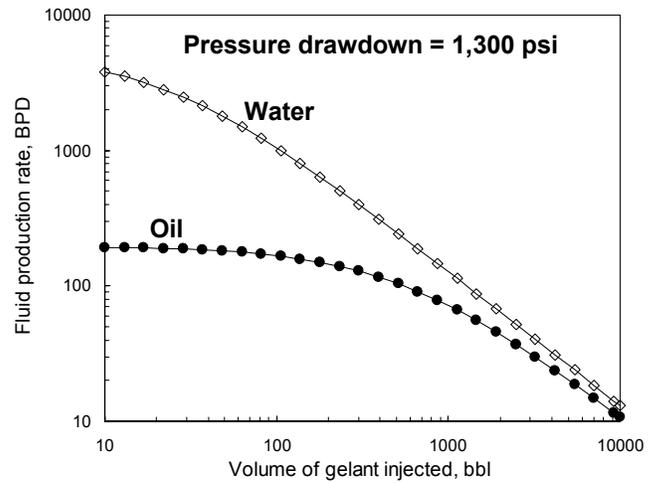
Fig. 4—Production rates versus gelant volume: Δp=1,300 psi.

Fig. 5—Production rates versus gelant volume: Δp=500 psi.