Society of Petroleum Engineers

SPE 70067

A Strategy for Attacking Excess Water Production

R. S. Seright, SPE, New Mexico Petroleum Recovery Research Center
R. H. Lane, SPE, Northstar Technologies International
R. D. Sydansk, SPE, Sydansk Consulting Services

This paper was prepared for presentation at the SPE Permian Basin Oil and Gas Recovery Conference held in Midland, Texas, 15–16 May 2001.

Abstract

This paper describes a straightforward strategy for diagnosing and solving excess water production problems. The strategy advocates that the easiest problems should be attacked first and diagnosis of water production problems should begin with information already at hand. A listing of water production problems is provided, along with a ranking of their relative ease of solution.

Conventional methods (e.g., cement, mechanical devices) normally should be applied first to treat the easiest problems—i.e., casing leaks and flow behind pipe where cement can be placed effectively and for unfractured wells where impermeable barriers separate water and hydrocarbon zones. Gelant treatments normally are the best option for casing leaks and flow behind pipe with flow restrictions that prevent effective cement placement. Both gelants and preformed gels have been successfully applied to treat hydraulic or natural fractures that connect to an aquifer. Treatments with preformed gels normally are the best option for faults or fractures crossing a deviated or horizontal well, for a single fracture causing channeling between wells, or for a natural fracture system that allows channeling between wells. Gel treatments should not be used to treat the most difficult problems—i.e., three-dimensional coning, cusping, or channeling through strata with crossflow.

Introduction

On average in the United States, more than seven barrels of water are produced for each barrel of oil.[1] Worldwide, an average of three barrels of water are produced for each barrel of oil.[2] The annual cost of disposing of this water is estimated to be 5-10 billion dollars in the US and around 40 billion dollars worldwide.[2]

Many different causes of excess water production exist (Table 1). Each of these problems requires a different approach to find the optimum solution. Therefore, to achieve a high success rate when treating water production problems, the nature of the problem must first be correctly identified.[3] Many different materials and methods can be used to attack excess water production problems. Generally, these methods can be categorized as chemical or mechanical (see Table 2). Each of these methods may work very well for certain types of problems but are usually ineffective for other types of problems. Again, for effective treatment, the nature of the problem must first be correctly identified.

Four problem categories are listed in Table 1 in the general order of increasing treatment difficulty. Within each category, the order of listing is only roughly related to the degree of treatment difficulty. Category A, "Conventional" Treatments Normally Are an Effective Choice, includes the application of water shutoff techniques that are generally well established, utilize materials with high mechanical strength, and function in or very near the wellbore. Examples include Portland cement, mechanical tubing patches, bridge plugs, straddle packers, and wellbore sand plugs.

A few comments may be helpful to clarify some of the listings in Table 1. First, the difference between Problems 1 and 4 is simply a matter of aperture size of the casing leak and size of the flow channel behind the casing leak. Problem 1, involving casing leaks *without* flow restrictions, is where the leak is occurring through a large aperture breach in the piping (greater than roughly 1/8 in.) and a large flow conduit (greater than roughly 1/16 in.) behind the leak. The use of Portland cement is favored for treating Problem 1. Problem 4, involving casing leaks *with* flow restrictions, is where the leak is occurring through a small aperture breach (e.g., “pinhole” and tread leaks) in the piping (less than roughly 1/8 in.) and a small flow conduit (less than roughly 1/16 in.) behind the leak. The use of gel is favored to successfully treat Problem 4. In this paper, the gels under discussion may include those formed from (1) chemically crosslinking water-soluble organic polymers, (2) water-based organic monomers, or (3) silicates.

The difference between Problems 2 and 5 is again simply a matter of aperture size of the flow channel behind the pipe. Problem 2, involving flow behind pipe *without* flow restrictions, is where the fluid flow is occurring through a large aperture flow conduit behind the pipe (greater than roughly 1/16 in.). The use of Portland cement is favored to treat Problem 2. This problem is often manifested by a total lack of primary cement behind the casing. Problem 5, involving flow behind pipe *with* flow restrictions, is where the flow behind pipe is occurring through a small aperture flow conduit (less than roughly 1/16 in.). The use of gel is favored to treat this problem. Problem 5 is often exemplified by micro-annuli flow behind the pipe. This problem often results from cement shrinkage during its curing during the well's completion.

The recognition, importance, challenge, and necessity of successfully treating Problems 2 and 5 have become much more prominent recently with the advent of regulatory-required mechanical integrity (hydro) testing of petroleum well tubing and casing strings.

Logically, identification of the excess water production problem should be performed before attempting a water shutoff treatment. Unfortunately, many (perhaps most) oil and gas producers do not properly diagnose their water production problems. Consequently, attempted water shutoff treatments frequently have low success rates. Several reasons exist for the inadequate diagnosis of excess water production problems. First, operators often do not feel that they have the time or money to perform the diagnosis, especially on marginal wells with high water cuts. Second, uncertainty exists about which diagnostic methods should be applied first. Perhaps 30 different diagnostic methods could be used. In the absence of a cost-effective methodology for diagnosing water production problems, many operators opt to perform no diagnosis. Third, many engineers incorrectly believe that one method (e.g., cement) will solve all water production problems or that only one type of water production problem (e.g., three-dimensional coning) exists. Finally, some service companies incorrectly encourage a belief that a "magic-bullet" method exists that will solve many or all types of water production problems.

A number of excellent papers have addressed candidate selection and various aspects of treating specific types of excess water production problems.[2-13] A common theme of many of these papers is a need for proper diagnosis of the excess water production problem. However, for the reasons mentioned above, such diagnosis is frequently not obtained. This paper focuses on a cost-effective strategy and methodology for diagnosing and solving excess water production problems. The objective of this paper is to provide a straightforward strategy and methodology for performing effective problem diagnosis so the practicing engineer does not forego problem diagnosis and, in turn, implement ineffective water shutoff treatments.

Proposed Strategy

Our proposed strategy for attacking excessive water production problems advocates that (1) the easiest problems should be attacked first and (2) diagnosis of water production problems should begin with information already at hand. To implement this strategy, a prioritization of water production problems is needed. Based on extensive reservoir and completion engineering studies and analyses of many field applications, the various types of water problems were prioritized and categorized from least to most difficult. This prioritization is listed in Table 1. The first three listings are the easiest problems (Category A, Problems 1-3), and their successful treatment has generally been regarded as relatively straightforward. Of course, individual circumstances can be found within any of these problem types that are quite difficult to treat successfully. For example, for Problem Type 3, impermeable barriers may separate water and hydrocarbon zones. However, if many water and oil zones are intermingled within a short distance, it may not be practical to shut off water zones without simultaneously shutting off some oil zones. The ranking of water production problems in Table 1 is based on *conceptual* considerations and issues related to the ease of treating each type of problem. We realize that operational and practical issues can make even the easiest problems in Table 1 very difficult to solve in practice.

Nevertheless, the first three problem types in Table 1 are generally easier in practice to treat than the others on the list. Therefore, one should look first for these types of problems.

In contrast, the last three problems (Category D, Problems 11-13) are difficult with no easy, low-cost solution. (Gel treatments will almost never work for these problems.) The intermediate problems (Categories B and C, Problems 4-10) are caused by linear-flow features (e.g., fractures, fracture-like structures, narrow channels behind pipe, or vug pathways). Certainly, much work remains to optimize the treatment of these problem types. However, substantial theoretical, laboratory, and field progress has been made in recent years toward solving these problems—especially using gels. As will be discussed shortly, Problems 4-7 (Category B in Table 1) normally are best solved using gelants—i.e., the fluid gel formulation before significant crosslinking occurs. Problems 8-10 (Category C) are best solved using preformed or partially formed gels (i.e., crosslinking products that will not flow into or damage porous rock).

A key element of the proposed strategy is to look for and solve the easiest problems in Table 1 before attempting to attack the more difficult problems. In many cases, engineers initially assumed that three-dimensional coning (Problem 11 in Table 1) caused the problem, whereas a small amount of subsequent diagnosis and analysis revealed the true source of water production was either flow behind pipe (Problem 2) or "two-dimensional coning" through a fracture (Problem 6). This knowledge could have substantially reduced the cost of solving the problem (since Problems 2 and 6 can be solved with relatively low-cost methods, whereas Problem 11 cannot). Also, by correctly identifying the problem first, the most appropriate method can be identified and the probability of successfully treating the problem increases significantly.

To help implement the proposed strategy, the following questions should be addressed in the order listed:

1. Is there a problem?
2. Is the problem caused by leaks or flow behind pipe?
3. Is the problem caused by fractures or fracture-like features?
4. Is the matrix-flow problem compounded by crossflow?

Is There a Problem? An important first question when attacking a water production problem is, do significant volumes of mobile oil remain in the pattern or in the vicinity of the well of interest? Three types of observations are commonly used to make this assessment. First, a pumper may notice that certain well(s) exhibit a sudden increase in water cut. Second, a well or pattern of wells may be noted as producing at significantly higher water/oil ratios (WORs) than other similar patterns. Third, plots of fluid production versus time may show an abrupt increase in WOR at a certain point. Results from reservoir simulation studies constitute a fourth, less common method sometimes used by large oil producers to analyze water production problems in large reservoirs.

The oilfield operator should recognize that two distinct types of water production exist. The first type, usually occurring later in the life of a waterflood, is water that is co-produced with oil as part of the oil's fractional flow characteristics in reservoir porous rock. If production of this water is reduced, oil production will be reduced correspondingly. The second type of water production directly competes with oil production. This water usually flows to the wellbore by a path separate from that for oil (e.g., water coning or a high permeability water channel through the oil strata). In these latter cases, reduced water production can often lead to greater pressure drawdowns and increased oil production rates. Obviously, the second type of water production should be the target of water shutoff treatments.

Understanding and conceptualizing the reservoir "plumbing" is a key to (1) distinguishing between the above two types of water production, (2) successfully diagnosing the water production problem, and (3) successfully implementing and designing water shutoff treatments.

Is the Problem Caused by Leaks or Flow Behind Pipe? Once the operator decides that the water cut is too high considering the remaining reserves and the water is produced via a flow path separate from that of the oil, one should ask whether the excess water production is caused by a relatively easy problem (as listed in Table 1)—in particular, by unrestricted casing leaks or by flow behind pipe. Some of the common methods used to diagnose these problems include (1) leak tests/casing integrity tests (e.g., hydro testing), (2) temperature surveys, (3) flow profiling tools (e.g., radiotracer flow logs, spinner surveys, production logging tools), (4) cement bond logs, (5) borehole televiewers, and (6) noise logs.

Many of these methods are used during routine surveillance of wells. Therefore, consistent with our proposed strategy, one should begin the diagnostic process by examining information already at hand. If this type of information is not available, then the above methods comprise a list of the first diagnostic methods that should be considered for implementation.

If a problem with unrestricted casing leaks or flow behind pipe (as defined in Table 1 and the subsequent paragraphs) is identified, that problem should be addressed before attempting to solve additional, more difficult problems that may exist. Some engineers disagree with this suggestion—arguing that they wish to apply a water shutoff method that solves multiple types of problems at once. While this fortuitous circumstance occasionally occurs, the optimum solution for treating the different types of problems usually varies considerably. For example, the optimum solution for an unrestricted flow behind pipe problem and that for a fracture that leads to an aquifer may differ considerably in (1) desired properties of the blocking agent, (2) volume of blocking agent placed, and (3) placement method. Thus, although a chosen treatment method may be effective in treating one of these two excessive water production problems, the chosen treatment will most likely be ineffective in treating the other water production problem.

Is the Problem Caused by Fractures or Fracture-Like Features? A critical aspect of diagnosing most excess water production problems is deciding whether fluid flow around the wellbore is radial or linear. Flow behind pipe, fractures, and fracture-like features are associated with linear flow, while radial flow generally occurs in matrix reservoir rock when these features are absent. (We recognize the special case of radial flow in fractures, e.g., for vertical fractures that cross horizontal wells. This case will be treated separately later. In this section, our consideration of radial flow is confined to flow in matrix, while linear flow refers to the presence of extremely permeable fracture-like features.) Simple calculations using the Darcy equation reveal that the approach for solving these linear flow problems must be fundamentally different than solving radial flow problems in matrix reservoir rock or sand.[14] Especially for gel treatments, linear versus radial flow problems differ radically in (1) gel properties desired, (2) placement procedures required, and (3) optimum volume of the gel placed. In particular, for radial flow problems, hydrocarbon productive zones *must* be protected during gelant placement.[14] For linear flow, an acceptable gel placement (without mechanically isolating zones) is much easier to achieve than in radial flow.

A number of methods are available to judge whether flow around a wellbore is linear (in fracture-like features) or radial (in matrix rock or sand). One simple method uses the Darcy equation for radial flow (Eq. 1).

$$q/\Delta p = \Sigma\, kh \,/\, [141.2\, \mu \ln (r_e / r_w)] \quad \text{..................................} \quad (1)$$

If the actual injectivity or productivity for a well (i.e., the left side of Eq. 1, $q/\Delta p$, in BPD/psi) is five or more times greater than the injectivity or productivity calculated using the Darcy equation for radial flow (i.e., the right side of Eq. 1), the well probably suffers from a linear flow problem.

LINEAR FLOW: $q/\Delta p >> \Sigma\, kh / [141.2\, \mu \ln (r_e/r_w)]$ .....(2)

On the other hand, if the left side of Eq. 1 is less than or equal to the right side, radial flow becomes likely.

RADIAL FLOW: $q/\Delta p \le \Sigma\, kh / [141.2\, \mu \ln (r_e/r_w)]$.........(3)

In the above equation, k is effective rock permeability in mD. If the zone contains water at residual oil saturation (S_{or}), k should take this into account. Typically the water relative permeability at S_{or} is between 5% and 30% of the absolute permeability, with 10% being a good estimate if k at S_{or} is not known. If the zone is producing only oil, k can be taken as the absolute permeability without incurring much error in the calculation. The permeability used in Eq. 1 should be taken from core analyses, log data, or pressure transient analyses. It should not be taken from production data. Net pay, h, in Eq. 1 has units of feet, while viscosity, μ, has units of cp. If the well is a water injector or if the well is producing a very high water cut, then the viscosity of water can be used (at the appropriate temperature). If the oil cut is significant, there may be value in performing two calculations using Eq. 1, one using water viscosity and one using oil viscosity. The natural log term in Eq. 1 can be assumed to have a value of 6 or 7. The pressure drawdown or buildup (Δp, in psi) in Eq. 1 must be reasonably current and applicable to the specific well of interest. It is a mistake to take this value from another well or to use a value that is too old. This pressure difference indicates a great deal about the problem of the specific well and is extremely important to measure both before and after (and even during) a gel treatment.

Of course, uncertainty exists for a significant range of conditions that do not satisfy either Eq. 2 or Eq. 3. Thus, injectivity/productivity calculations will not always distinguish between radial and linear flow. Nevertheless, they frequently do provide a definitive indication of the flow geometry near the wellbore. Since the calculations are easily performed using data often at hand, they provide a low-cost diagnostic method that should be considered when diagnosing any excess water production problem.

In addition to the injectivity/productivity calculations discussed above, several other methods can be used to determine if fractures or fracture-like features are the source of the water problem. These other methods include (1) core and log analyses (especially from highly deviated or horizontal wellbores), (2) pulse tests/pressure transient analyses, and (3) interwell tracer studies.

Various logging methods have been used to detect and characterize fractures (Chapter 3 of Ref. 15). However, these methods must be used with caution since they usually measure properties at or near the wellbore. The value of these methods can be increased if the wellbore is deviated to cross the different fracture systems (i.e., fractures with different orientations).

Pressure transient analyses have often been used to characterize fractured reservoirs (Chapter 4 of Ref. 15). Reportedly, these methods can estimate the fracture volume, the fracture permeability, and, possibly under some circumstances, the minimum spacing between fractures. Pressure interference tests can also indicate fracture orientation. In addition to unsteady-state methods, steady-state productivity indexes were also suggested as a means to estimate fracture permeability.

Interwell tracer studies provide valuable (and often relatively inexpensive) characterizations of fractured reservoirs, especially for use in judging the applicability of gel treatments to reduce channeling.[16,17] Interwell tracer data provides much better resolution of reservoir heterogeneities than pressure transient analyses.[17] Tracer results can indicate (1) whether fractures or fracture networks are probably present and if those fractures are the cause of a channeling problem, (2) the location and direction of fracture channels, (3) the fracture volume, (4) the fracture conductivity, and (5) the effectiveness of a remedial treatment (e.g., a gel treatment) in reducing channeling.[18] For operators producing from mature, highly fractured oil reservoirs, low cost and operationally easy tracer techniques exist that can help diagnose excessive water production problems.

Is the Matrix-Flow Problem Compounded by Crossflow? Once fractures and fracture-like features are eliminated as possibilities, the problem is deduced to be radial in nature (i.e., radial flow exists in the matrix rock around the wellbore). Next, the possibility of crossflow between reservoir strata must be addressed. If fluids can crossflow between adjacent water and hydrocarbon strata (and flow is radial), a gel treatment should not be attempted.[19] Even if gelant is only injected into a single zone, it will crossflow into and damage the oil producing zones away from the wellbore. Thus, no matter how much gelant is injected, the treatment will be ineffective in promoting conformance.[19] In contrast, if fluids cannot crossflow between zones and sealing Portland cement exists that prevents vertical flow immediately behind the casing, a gel treatment can be effective if gelant injection is placed only in the offending water zones.[14]

Several methods are used to assess whether crossflow exists between strata, including (1) pressure tests between zones, (2) various logs for determining fluid saturations, permeability, porosity, and lithology, (3) injection/production profiles, (4) simulation, and (5) seismic methods. The most straightforward method tests pressure differences between zones. Commonly, a packer is placed between two zones and one of the zones is allowed to pressure up. If a significant pressure can be maintained across the packer, effective barriers to crossflow exist between the zones. If a pressure difference cannot be maintained, crossflow between the zones may occur. If the operator does not know whether crossflow occurs, he should assume that crossflow exists.

WOR History Plots. Plots of water/oil ratio (WOR) versus time can provide a valuable indication of when an excess water problem develops.[2,20] Along with other information, such plots can also aid in identifying the cause of the problem.

However, these "diagnostic plots" (of WOR or WOR derivative versus time) should not be used alone to diagnose excessive water production mechanisms and problems.[21,22] This method was said to be capable of distinguishing whether a production well is experiencing premature water breakthrough caused by water coning or channeling through high permeability layers.[20] According to this method, gradually increasing WOR curves with negative derivative slopes are unique for coning problems, and rapidly increasing WOR curves with positive derivative slopes are indicative of a channeling problem. As far as we are aware, this method has not been used to distinguish between linear flow (fracture or flow behind pipe) and radial flow for either channeling or coning. As mentioned above, the linear/radial distinction is extremely important—much more so than whether the problem is due to generic channeling or coning.

Recently, reservoir models were built for water coning and channeling, respectively, and a sensitivity analysis was performed using numerical simulation.[21,22] Reservoir and fluid parameters were varied to examine WOR and WOR derivative behavior for both coning and channeling production problems. The results from this study demonstrated that multi-layer channeling problems could easily be mistaken as bottomwater coning, and vice versa, if WOR diagnostic plots are used alone to identify an excessive water production mechanism. Hence, WOR diagnostic plots can easily be misinterpreted and should therefore not be used alone to diagnose the specific cause of a water production problem.

Solutions To Specific Types Of Problems

After diagnosing the cause(s) of the excess water production, what approach should be taken to solve the problem? As mentioned earlier, each problem type usually requires a different approach, including (1) choice of treatment method, (2) properties of the conformance or blocking agent, (3) volume of conformance or blocking agent used, and (4) placement method. The remainder of this paper will focus on the use of gelant or gel treatments, and will address whether and how these treatments should be applied to successfully treat each of the problem types listed in Table 1.

Casing Leaks (Problems 1 and 4 in Table 1). The most common methods to repair casing leaks (i.e., for Problem 1) involve either cement[23,24] or mechanical patches.[2,25] However, these methods have generally not been very successful when treating small casing leaks, such as "pinhole" or thread leaks (Problem 4). In particular, cement has difficulty penetrating through small leaks. With luck, cement may lodge in and plug the leak, but small mechanical shocks often easily dislodge the cement plug. Gel treatments can be more successful for these applications.[26-28] Appropriately designed gelants flow easily through the small casing leaks and some distance into the formation surrounding the leak. Thus, the gel treatment is directed at stopping flow in the porous rock around the vicinity of the casing leak, rather than solely attempting to permanently plug the casing leak itself. If the resultant gel (placed in the matrix reservoir rock) can withstand the near wellbore pressure gradients, a small radius of penetration (e.g., ~1 ft) may be adequate to stop flow. Consequently, gelant volumes can be quite small. Of course, greater gel volumes and/or other treatment methods may be needed if flow behind pipe or fractures exist in the vicinity of the casing leak.

What placement and permeability reduction properties are desired for gels used to plug casing leaks? Since the objective is to achieve total water shutoff from the leak and since small gel volumes are often used for this application, the gel plug should be relatively strong and must have a very low permeability. Rigid gels can be prepared from several materials that yield permeabilities in the low microdarcy range.[29,30] Gels for this application have often been formulated with relatively high concentrations (4-7%) of acrylamide polymers having a relatively low molecular weight (on the order of 250,00 to 500,000 daltons).[31] Gelants for this application should be of relatively low viscosity and experience essentially no crosslinking of the polymer during gel treatment placement.

Flow Behind Pipe (Problems 2 and 5 in Table 1). Problems with unrestricted flow behind pipe are usually treated with cement.[23] Cement can perform extremely well for this type of application if the channel to be plugged is not too narrow (i.e., Problem 2). When narrow channels are encountered (Problem 5, such as micro-annuli between cement and the formation or the pipe), cement often cannot be placed effectively through small or constricted flow paths. Gels provide a better solution for this case, since they can flow or extrude readily through narrow constrictions.[32,33] The ability of gels to withstand high pressure gradients increases with decreasing channel width.[34] Therefore, gel alone cannot be expected to plug large voids behind pipe. In some cases, gelants or gels were injected first (to penetrate into narrow constrictions), and cement was injected subsequently to fill and plug larger near wellbore voids and to prevent gel from washing out from their strategic locations.[35]

When treating flow behind pipe problems where a substantial drawdown pressure (i.e., >100 psi) exists, gelants are often employed rather than preformed or partially formed gels. Three reasons often favor gelant injection when treating this problem type. First, flow constrictions in small flow channels behind pipe may prevent full penetration of preformed gel into the offending channels. These constrictions do not significantly impede flow and placement of gelant solutions. Second, gelant invasion into permeable matrix rock adjacent to the channel behind pipe is usually beneficial when treating this type of problem. In contrast, preformed gels will not penetrate appreciably into the permeable matrix. Third, because of relatively high near-wellbore drawdown pressures, gel in the channel probably will washout much more easily than gel formed in the permeable matrix. Methods of sizing gel treatments for these applications have been strictly empirical to date.

In certain circumstances, properly formulated gels of preformed or partially formed crosslinked organic polymer gels may be favored when treating long intervals of micro-annuli between the primary cement and the formation.

Unfractured Wells with Effective Barriers to Crossflow (Problem 3). Often, when radial flow exists around a well (i.e., fractures are not important), impermeable barriers (e.g., shale or anhydrite) separate hydrocarbon-bearing strata from a zone that is responsible for excess water production. When the water zone is located at the bottom of the well, cement or sand plugs are used most commonly to stop water production. When the water zone is located above an oil zone, historically the most common water shutoff methods include cement or carbonate squeezes (into perforations) or mechanical packers or patches[23]—i.e., the conventional treatments of Category A.

However, gels, involving gelant injection, have also been used frequently to treat these problems.[7,28,32,36] In these instances, the problem solution falls into Category B of Table 1. Gels have two advantages over cements and carbonates for some applications.[32] First, gelants can flow into porous rock, whereas cements and particulate blocking agents are filtered out at the rock surface. Cements (including "micro-fine cement") only invade and plug porous rock or sands of normal permeabilities (e.g., sandstone and sands of <1,000 mD) to any significant distance by fracturing or parting the rock or sand when sufficient injection pressures are provided. If the cement does not adhere adequately to the rock in the perforation or other large void (e.g., because of chemical incompatibility or mechanical shock), the zone may not be sealed sufficiently. In contrast, gels (i.e., after gelation) can form an impermeable rubbery mass that extends past the rock surface, well into the porous rock. Second, gelants and gels can penetrate into and plug narrow channels (e.g., micro-annuli) behind pipe in the vicinity of the zone to be shut off.[32] Therefore, in some cases, gels can provide a more effective seal in the zone to be plugged.

When treating radial flow problems using gels or similar blocking agents, hydrocarbon zones *must* be protected during gelant placement. Otherwise, the blocking agent will probably also damage the hydrocarbon zones.[14] Mechanical isolation of zones is the most obvious method to protect oil zones during gelant placement. However, other methods exist—notably dual injection.[7,37,38] As an example of dual injection, gelant might be injected down coiled tubing into the water zone while non-damaging water or hydrocarbon fluid is injected simultaneously down the annulus into the oil zone (while the two zones are in fluid communication). Downhole pressure gauges in the tubing and annulus are carefully monitored to maintain a very delicate pressure balance. Near the wellbore, this balance minimizes gelant crossflow into the oil zones and protective-fluid crossflow into the water zone. This method is of particular interest and value for wells where mechanical zone isolation is impractical, especially gravel-packed wells and wells with flow behind pipe. The method and its associated gel treatment will not be effective in cases where laterally extensive barriers (e.g., shale or anhydrite layers) are not present out away from the wellbore.[19] The dual injection technique is considered to be an advanced zone isolation technique that must be carefully designed and tailored to individual well problems and often requires computer simulation support for its successful implementation.

For gel applications in unfractured injection or production wells where crossflow does not occur, how much gel should be injected and what properties should the gel have? This question is easily answered by considering Fig. 1, which was generated using the Darcy equation for radial flow.[39] This figure applies to gel treatments both in injection and productions wells.

Fig. 1 plots the fraction of original injectivity or productivity retained after a polymer or gel treatment as a function of the residual resistance factor (i.e., the permeability reduction provided by the polymer or gel). Fig. 1 applies to a waterflooded reservoir with a 40-acre, 5-spot pattern with a unit-mobility displacement. The wellbore radius was 0.33 ft. Two cases of radii of gelant penetration (r_{gel}) are presented—5 ft and 50 ft. A comparison of these two curves reveals that for a given residual resistance factor, the injectivity or productivity losses are not strongly dependent on the radius of gelant penetration. Therefore, the performance of the gelant treatment is not sensitive to the volume of gelant injected. A five-foot radius of penetration will often be adequate for many applications, if the gel can withstand the high pressure gradients near the wellbore. Fig. 1 also indicates the desired properties of the gel. In the water zones, for the typical range of gelant penetrations, residual resistance factors of 20, 50, and 100, will provide water productivity losses of 80%, 90%, and 95%, respectively. These values are adequate for most radial flow problems.

In some cases where cold water is injected into wells in hot reservoirs, thermal fractures may develop and extend a significant distance (e.g., 10 to 100 ft or more) from the wellbore.[40,41] In these circumstances, the gel treatment should plug both the matrix and the fractures in the offending zone.

Many polymers and gels can reduce permeability to water (k_w) more than that to oil (k_o) or gas (k_{gas}). For the credible experimental data reported to date, polymers and gels may reduce k_w more than k_o, however, they always reduce k_o to some extent. In the best cases, Zaitoun and Kohler[42] reported that adsorbed polymers significantly reduced k_w at any given water saturation, while the oil relative-permeability curve was basically unaffected by the polymer. However, the polymer increased the irreducible water saturation, thus lowering the endpoint relative permeability to oil. Therefore, for all practical purposes in zones with high oil saturations, the polymer treatment reduces the effective permeability to oil to some extent.

For gel treatments applied to water injection wells, the disproportionate permeability reduction is of no value. However, in production wells, the property is critical to the success of gel treatments if hydrocarbon zones are not protected during gelant placement. Even then, the property is of value only when zones with high hydrocarbon saturation are distinct from the offending water producing zones.[43] In other words, this "disproportionate permeability reduction" will not mitigate water production from a reservoir that has effectively only one zone. When a single zone exists, even if the polymer or gel can significantly reduce permeability to water without affecting the permeability to oil, the average fractional flow of water and oil from that zone must remain the same. If the polymer or gel near a production well allows oil to pass but not water, the water saturation will increase near and just beyond the gel bank, thus, decreasing the relative permeability to oil until the fractional water and oil flows match the values that existed before the polymer or gel treatment. Therefore, unless a particular zone is at its irreducible water saturation, a polymer or gel treatment will always cause some loss of oil productivity, even if the polymer or gel reduces k_w without affecting k_o. This loss of oil productivity necessarily will be in direct proportion to the loss of water productivity caused in that particular zone.

A common misconception is that the disproportionate permeability reduction will be of value mainly in treating unfractured production wells where fluid flow is radial around the wellbore. However, two technical obstacles currently impede this type of treatment from being commonly successful. First, if zones are not isolated during gelant placement, then generally, the residual resistance factor (permeability reduction value) in the oil zone must be less than two while the residual resistance factor in the water zone must be greater than 10. The reason for this requirement can be appreciated by considering Fig. 1. For radial flow, relatively small residual resistance factors (F_{rr}) can cause significant injectivity or productivity losses. For example, for a gel radius of 50 ft, a F_{rr} value of 2 causes a 27% loss in productivity, while a F_{rr} value of 10 causes a 75% loss. Both of these losses might be considered unacceptable if these are oil zones. Thus, in unfractured wells, oil residual resistance factors (F_{rro}) provided by the gel must be small.

A second technical obstacle also thwarts the disproportionate permeability reduction from being usable in practice when treating radial flow problems. Especially for gels and/or products of gelation reactions, F_{rro} values less than two may be difficult to achieve in a predictable and controllable manner.[29,44] Low F_{rro} values usually mean that gelation was incomplete and the products of the gelation reaction were small gel particles that become trapped in pore throats. These particles occupy a small fraction of the aqueous pore space. Gelation reactions are usually sensitive to pH, salinity, and other factors, and these factors are influenced by the rock lithology and resident fluid composition.[29,44] Consequently, small differences in rock lithology and reservoir conditions may significantly change the concentration and size of particles formed during the early stages of gelation—ultimately resulting in residual resistance factors that are unpredictable and uncontrollable.

As will be discussed in the next section, the disproportionate permeability reduction currently is of much greater value in treating linear flow problems (i.e., fractured production wells) than radial flow problems.

When treating water production problems in unfractured reservoirs with barriers to crossflow, gel treatments can be applied in either injection or production wells.

2-D Coning: Hydraulically Fractured Production Wells (Problem 6). When production wells are hydraulic fractured, the fracture often unintentionally breaks into water zones, causing substantially increased water production. Gelant treatments have significant potential to correct this problem. These gelant treatments rely on the ability of these gels to be placed in the rock matrix adjacent to the fractures and to reduce permeability to water much more than that to hydrocarbon (disproportionate permeability reduction). An engineering-based method was developed for designing and sizing *gelant* treatments in hydraulically fractured production wells.[45] This design procedure was incorporated in user-friendly graphical-user-interface software that can be downloaded from the internet at http://baervan.nmt.edu/randy.

In these matrix rock treatments, gelants flow along the fracture and leak off a short, predictable distance into the matrix rock of all the zones (water, oil, gas). Success for such a treatment requires that the gel reduce permeability to water much more than that to hydrocarbon in the treated matrix rock. The ability of the gel to stop water entry into the fracture is determined by the product of gelant leakoff distance (from the fracture face) and the residual resistance factor (permeability reduction factor) provided by the gel. For example, consider the case where the gelant leaks off 0.2 ft into both water and oil zones, and in the gel-contacted rock, permeabilities to water and oil are reduced by factors 50,000 and 50, respectively. (These properties have been reported for a gel formulation.[46]) In this case, the gel only adds the equivalent of 10 feet of additional rock that the oil must flow through to enter the fracture (i.e., 0.2 ft x 50). In contrast, for the water zone, the water must flow through the equivalent of 10,000 ft of additional rock to enter the fracture (i.e., 0.2 ft x 50,000). Thus, in this circumstance, the gel can substantially reduce water production without significantly affecting oil productivity.

In this method, fluid entry into the fracture is controlled by gel in rock next to the fracture.[45] Ideally, fracture conductivity is not reduced significantly, since it allows a conductive path for oil flow into the wellbore. To some extent, gravity segregation of the gelant (between placement and gelation) will mitigate damage to the fracture when the excessive water production originates from an underlying aquifer. However, to minimize fracture damage, an oil or water post-flush could be used to displace gelant from the fracture.

From a rigorous viewpoint, the method assumes that impermeable barriers (e.g., shale or calcite) separate adjacent zones.[45] However, the method should frequently provide acceptable predictions even if crossflow can occur between the water bearing and oil bearing zones. For example, consider the case where oil lies on top of water in a single formation (i.e., a common situation where coning becomes a problem). Previous work[43,46] showed that gravity alone can retard water influx into oil zones much more effectively when the water must "cusp" to a linear pressure sink (i.e., a vertical fracture or a horizontal well) than when the water "cones" to a point pressure sink (i.e., a partially penetrating vertical well). For the type of gel treatment that we are proposing for application in hydraulic fractures, in many cases, gravity may be sufficient to minimize water invasion into the hydrocarbon zones of a single formation. Of course, the degree of water invasion (coning) into hydrocarbon zones increases with increased production rate, pressure drawdown, vertical formation permeability, and hydrocarbon viscosity, and decreases with increased water-hydrocarbon density difference, horizontal formation permeability, and oil column thickness.[43,46] If water invades too far into the hydrocarbon zone, a water block could form that reduces hydrocarbon productivity.

To use this procedure to reduce water production from a hydraulic fracture, field data are needed, coupled with results from two simple laboratory experiments.[45] The needed field data include: (1) fluid production rates before the gel treatment, (2) downhole static and flowing pressures before the gel treatment, (3) permeabilities, porosities, and thickness of the relevant zones, (4) water and oil viscosities at reservoir temperature, and (5) well spacing or distance between wells. These parameters are often available during conventional gel treatments. The downhole pressure drops are critically important for this method. They must be reasonably current and measured specifically for the well to be treated.

Use of the procedure also requires oil and water residual resistance factors from laboratory core experiments.[45] These experiments must be conducted using the gelant, oil, brine, rock, and temperature that are representative of the intended application. In the absence of laboratory oil and water residual resistance factors, the model can use field data to back-calculate these values in situ after a gel treatment. This information may be useful when designing similar treatments in nearby wells. These calculations have also been incorporated into the software. For cases where residual resistance factors are calculated from field data, three parameters (from a similar, previous gelant treatment) are required in addition to the five items listed in the previous paragraph. These three parameters are (1) fluid production rates after the gel treatment, (2) accurate downhole static and flowing pressures after the gel treatment, and (3) the volume of gelant injected.

Although somewhat challenging to properly design and execute, strong and/or rigid gel treatments, involving the injection of partially formed gels, can be used to treat 2-D water coning in hydraulically fractured production wells. In this treatment strategy, gravity is exploited to selectively place a partially gelled solution in the lower portion of the fracture.[9]

Natural Fracture System Leading to an Aquifer (Problem 7). Several operators reported impressive (but often short-lived) results from polymer and gel treatments in production wells in the Arbuckle, Ellenberger, and Madison formations.[4,47,48] These treatments were applied to reduce excessive water production emanating via natural fractures from underlying aquifers that provided strong water drives.

Phillips applied 37 treatments in Arbuckle formations using eight different organic polymer and polymer-crosslinker combinations.[47] In their treatments, the average incremental recovery was 1.9 STB/lb polymer, with a range from -1 to 13 STB/lb. The average time for the well to return to the pre-treatment WOR, and oil production rate was 12 months, with a range from 2 to 43 months. The treatments typically reduced total fluid productivity by a factor of two. Interestingly, Phillips found that the incremental oil recovery, treatment lifetime, and WOR reduction did not correlate with the mass of polymer injected (390 to 1,400 lbs/well), type of polymer or gel treatment (8 types used), productivity reduction induced by the treatment (1 to 5), structural position of the completion, completion type, fluid level before the treatment, or the Arbuckle reservoir.[47] (Treatments were applied in several Arbuckle reservoirs.)

A review of 274 water shutoff treatments that were applied between 1970 and 1990 focused on gel treatments in two naturally fractured carbonate formations (Arbuckle and Ellenberger).[4] For the results published, the median WOR was 82 before gel injection, 7 shortly after gel treatment, and 20 after one to two years following the treatment. The median oil productivity increased by 3 shortly after treatment and returned to pre-treatment levels after one to two years.

The positive effects of these treatments were generally short-lived in the Arbuckle and Ellenberger formation. However, for several gel applications in the Madison formation in Wyoming, reductions in water cut were sustained for many years.[46] Chromium(III)-carboxylate/acrylamide-polymer gel water shutoff treatments also were applied to 14 economically marginal production wells of the old and mature Big Lake field in Texas.[9] Water production was decreased, on the average, from 3,410 to 993 BWPD and oil production was increased, on the average, from 2 to 14 BOPD. The main producing zone of these 14 oil wells was the dolomitic Grayburg formation that was naturally fractured. Excess water production was believed to be coning up through vertical fractures from the underlying active aquifer.[9,63] During these successful gel treatments applied to the Madison and Grayburg formations, *partially formed* gels were injected. Thus, the gel solution to these two excess water production problems (Problem 7) shifts into Category C of Table 1.

Results from treatments applied to Problem 7 raise a number of important questions. First, what is the water shutoff mechanism for these treatments? Do the treatments work primarily because gelant penetrates into the porous rock and provides disproportionate permeability reduction? Or do the treatments work because gels selectively plug the lower parts of the fracture system more than the upper parts? Is it better to inject a gelant that forms a strong gel or a weak gel? Why were the benefits from the treatments temporary in most cases? How should these treatments be sized? Should preformed gels be injected instead of gelants? Unfortunately, these questions remain unanswered for the present.

Individual Fractures that Cause Channelling from Injectors to Producers (Problem 9). Gel treatments currently provide the most effective means to reduce channeling through fractures.[4,49-51] Except in narrow fractures (i.e., fracture widths less than 0.02 in.), extruded gels have a placement advantage over conventional gelant treatments when treating channeling through fractures. To explain, during conventional gel treatments, a fluid gelant solution typically flows into a reservoir through both the porous rock and the fractures. After placement, chemical reactions (i.e., gelation) cause an immobile gel to form. During gelant injection, fluid velocities in the fracture are usually large enough that viscous forces dominate over gravity forces.[52] Consequently, for small-volume treatments, the gelant front is not greatly distorted by gravity during gelant injection. However, after gelant injection stops, a small density difference (e.g., 1%) between the gelant and the displaced reservoir fluids allows gravity to rapidly drain gelant from at least the upper part of the fracture.[52] Generally, gelation times cannot be controlled well enough to prevent gravity segregation in the time between gelant injection and gelation.

Alternative to conventional gelant treatments, formed (preformed) gels can be extruded through fractures. Since these gels are 10^3 to 10^6 times mores viscous than gelants, gravity segregation for gels is much less important than for gelants. For some of the most successful treatments in fractured reservoirs, formed gels were extruded through fractures during most of the placement process.[11,49-51]

The extrusion properties of a Cr(III)-acetate-HPAM (chromium(III)-carboxylate/acrylamide-polymer) gel have been characterized as a function of injection rate and time and fracture width and length.[34] Gels concentrate or dehydrate during extrusion through fractures. During flow in a fracture, the rate of dehydration of these gels varies inversely with the square root of time. This fact allows gel propagation along fractures to be predicted.[34,53] (See Figs. 2 and 3 for propagation of a Cr(III)-acetate-HPAM gel in a vertical fracture of fixed height.) To maximize gel penetration along fractures, the highest practical injection rate should be used. However, in wide fractures or near the end of gel injection, gel dehydration may be desirable to form stronger and rigid gels that are less likely to washout after placement. In these applications, reduced injection rates may be appropriate. In single, wide (i.e., >0.5 in.) vertical fractures (of fixed height) where short distances of penetration are needed, the gel volume required increases roughly with the distance of penetration. In single vertical fractures (of fixed height) with narrow to moderate widths (i.e. 0.02 to 0.5 in.), the required gel volume increases roughly with the distance of penetration raised to the 1.5 power. A rule of thumb derived from this latter behavior is that doubling the distance of penetration along a given fracture (of narrow or moderate width) requires tripling the volume of injected gel.

A minimum pressure gradient is required to extrude a given gel through a fracture.[34] After this minimum pressure gradient is met, the pressure gradient during gel extrusion is insensitive to the flow rate. The pressure gradient required for gel extrusion varies inversely with the square of fracture width.[34] The volume of gel that can be injected depends critically on fracture width and gel properties (i.e., gel composition and rigidity). For a typical Cr(III)-acetate-HPAM gel (containing 0.5% polymer), a 2 psi/ft pressure gradient was noted during extrusion through a 0.1-in.-wide fracture.[34] Therefore, in field applications, knowledge and/or estimation of fracture widths is important for deciding the composition and properties of the gel to be injected.

For interwell channeling, the effective average width of the most direct fracture can be estimated from interwell tracer tests.[54,55] Tester *et al.*[54] suggested that the best estimate of the volume of a fracture path is provided by the modal volume (i.e., the volume associated with the peak concentration in the produced tracer distribution). The interwell tracer time (t in days) associated with this peak concentration can be use to estimate effective average fracture width (w_f in inches)[55]:

$$w_f = 5.4 \times 10^{-5} L_f [\mu /(t\Delta p)]^{1/2} \text{ ,} \quad (4)$$

where L_f is the injector-producer well separation (in feet), μ is tracer fluid viscosity (in cp), and Δp is the downhole interwell pressure drop (in psi).

For some applications where wide fractures or large vugs are present, gels alone may not provide sufficient mechanical strength and flow resistance to plug the channel. In these cases, particulate matter (sand, cellophane, fibers, nut shells, etc.) can be added to increase the mechanical strength and plugging characteristics of the gel.[56-58]

Gel jobs to treat individual fractures that cause channeling from injectors to producers can be applied in either injection or production wells.

Faults or Fractures that Cross Deviated or Horizontal Wells (Problem 8). Deviated and horizontal wells are prone to intersect faults or fractures. If these faults or fractures connect to an aquifer, water production can jeopardize the well.[51] Often, the completions of these wells severely limits the use of mechanical methods to control fluid entry. In contrast, gel treatments can provide a viable solution to this type of problem. However, conventional gelant treatments are not the desired form of remediation in this case. In a conventional gelant treatment, a fluid gelant solution is injected that flows down the well into the target fracture or fault and *also* leaks off into the porous rock around the wellbore and the fracture or fault. The resultant gel may plug or severely restrict water entry into the fracture or fault. Unfortunately, the gelant will *also* flow into the exposed hydrocarbon bearing rock all along the well during the placement process. Consequently after gelation, oil productivity can be damaged as much as water productivity. Alternatively, a formed gel can be pumped down the well and selectively placed in the fracture.[34,51,53] The gel formulation may exist as an uncrosslinked fluid at the wellhead, so long as significant gelation occurs before the gelant reaches the oil zone. Then, because formed gels do not enter or flow through porous rock,[59] damage to oil productivity can be minimized. In contrast, the gel can extrude selectively into and plug the fracture or fault. When the well is returned to production, gel remaining in the wellbore can often flow back to the surface. If designed properly, gel in the fault or fracture will remain in place because the fracture width is much smaller than the diameter of the wellbore. (The pressure gradient required to mobilize formed gels varies inversely with the square of fracture width or tube diameter.[34]) Alternatively, coiled tubing can be used to circulate gel out from the wellbore.[32] (In practice, water, oil, or an uncrosslinked polymer solution is often injected immediately after the gel in an attempt to displace gel from the wellbore into the fracture.[51] Since this displacement is unstable, its effectiveness can be questioned.)

If the water production problem is caused by a single fracture or fault that intersects the horizontal wellbore, the distance of gel penetration into the fracture need not be particularly large.[60] In this case, the benefit gained varies approximately logarithmically with the distance of gel penetration.[53] However, this conclusion is specific to one particular scenario—i.e., a single fault or fracture intersecting a horizontal well. The conclusion may not be valid for vertical wells or if multiple fractures or faults intersect a horizontal well, or if a natural fracture system is present. Furthermore, even for the case of a single fault or fracture that intersects a horizontal well, some value may be realized by injecting a significant amount of gel to mitigate the possibility of gel washout after the well is returned to production.

For horizontal wells that cross faults or fractures, simple calculations based on productivity data can give at least a rudimentary indication of the width of the fracture that causes the excess water production.[53] The calculations can also give an idea of how far the gel should penetrate to provide a beneficial effect.[34] Using laboratory data coupled with field data collected before, during, and after gel injection of similar gel treatments, the calculations can also give an indication of how far the gel actually penetrated into the fracture.[53] To successfully make these determinations, accurate flowing and static downhole pressures are critical measurements that must be obtained during field applications of these gel treatments.

In vertical fractures that cut through vertical wells, gel flow in the fracture is generally linear. However, in vertical fractures that cut through horizontal wells, the flow geometry is radial (at least, near the well). During gel extrusion through fractures of a given width, the pressure gradient and degree of gel dehydration were nearly independent of position and velocity during both radial and linear flow.[61] Because the pressure gradient during gel extrusion is almost independent of injection flux, the pressure gradient is nearly independent of radial position from the wellbore. Thus, the distance of gel penetration from the wellbore (L_{gel} or r_{gel}) can be estimated regardless of whether flow in the fracture is linear or radial.

$$L_{gel} \text{ or } r_{gel} = (\Delta p_{gel} - \Delta p_{water})\ (dp/dl)_{gel}\ , \qquad (5)$$

where Δp_{water} is the pressure drawdown (i.e., the downhole pressure difference between the wellbore and the formation) during water injection, Δp_{gel} is the pressure drawdown during gel injection, and $(dp/dl)_{gel}$ is the pressure gradient required for gel extrusion through the fracture of interest. As mentioned earlier, the pressure gradient for gel extrusion varies inversely with the square of fracture width.[34] For one Cr(III)-acetate-HPAM gel (with 0.5% HPAM) that is commonly used in field applications, the pressure gradient (in psi/ft) for gel extrusion is related to fracture width (in inches) using Eq. 6.

$$(dp/dl)_{gel} = 0.02 / (w_f)^2 \qquad (6)$$

Of course, the coefficient in Eq. 6 (e.g., 0.02) depends on gel composition. More rigid gels exhibit greater coefficients and pressure gradients during extrusion.

Injector-Producer Channeling in Naturally Fractured Reservoirs (Problem 10). Some of the most successful gel treatments were applied to reduce water and gas channeling in naturally fractured reservoirs.[11,49,50,62,63] The primary objective of these gel treatments was to improve sweep efficiency and to promote incremental oil production. A secondary benefit of the gel treatments was the substantial reduction of excessive water and gas production at the offsetting production wells. During these injection well applications, the time required to inject large volumes (e.g., 10,000 to 37,000 bbls) of gel was typically greater than the gelation time by a factor around 100.[11,49,50] Thus, formed gels extruded through fractures during most of the placement process. Several operators reported that oil recovery increased with increased volume of gel injected per treatment.[11,49,50] However, sizing of these treatments to date has been empirical—dictated primarily by perceived economic and operational limitations. Engineering-based sizing methods are under development for this type of problem.[55]

Theoretical work indicates that gel treatments have the greatest potential when the conductivities of fractures that are aligned with direct flow between an injector-producer pair are at least 10 times the conductivity of off-trend fractures.[55] Gel treatments also have their greatest potential in reservoirs with moderate to large fracture spacing. Produced tracer concentrations from interwell tracer studies can help identify reservoirs that are good candidates for water shutoff using gel treatments. The average width of the most direct fracture between an injector-producer pair can be estimated from the breakthrough time from an interwell tracer study using Eq. 4. Since the ability of a gel to extrude through a fracture depends critically on the fracture width or conductivity,[34,59,61] this knowledge is important when selecting an appropriate gel formulation for the treatment.

Simulation studies indicate that the potential for successful application of a gel treatment becomes greater as the peak produced tracer concentration increases above 20% of the concentration the injected tracer concentration.[55] When produced tracer concentrations are low (i.e., less than 1% of the injected tracer concentration), gel treatments are unlikely to be effective. However, results from a poorly designed tracer test can mislead one to believe that a gel treatment has little potential. For example, if the tracer bank is too small, dispersion can reduce produced tracer concentrations to very low values in a fracture system even though a gel treatment has excellent potential.

Gel treatments to reduce injector-producer channeling in naturally fractured reservoirs can be applied in either injection or production wells.

Three-Dimensional Coning and Cusping (Problems 11 and 12). Gelant or gel treatments have an extremely low probability of success when applied toward cusping or three-dimensional coning problems occurring in unfractured matrix reservoir rock. When treating coning problems, a common misconception is that the gelant will only enter the water zones at the bottom of the well. In reality, this situation will occur only if the oil is extremely viscous and/or the aqueous gelant is injected at an extremely low rate (to exploit gravity during gelant placement). In the majority of field applications to date, the crude oils were not particularly viscous, and gelant injection rates were relatively high. Consequently, one must be concerned about damage that polymer or gel treatments cause to hydrocarbon-productive zones.

Even if a polymer or gel reduces k_w without affecting k_o, gel treatments have limited utility in treating 3-D coning problems. Extensive numerical studies using a variety of coning models indicate that gel treatments can only provide improvement if the desired production rate is less than 1.5 to 5 times the pretreatment critical rate.[43,65] This circumstance rarely occurs.

In contrast to the very limited potential of polymers and gels in successfully treating 3-D coning, these treatments have much greater potential for successfully treating "two-dimensional coning" where vertical fractures cause water from an underlying aquifer to be sucked up into a well. Whereas gel treatments will only raise the critical rate by factors from 1.5 to 5 in unfractured wells, they can raise the critical rate by more than a factor of 100 in fractured wells.[43,65]

A number of literature reports suggested that gel or foam treatments were effective in mitigating 3-D coning. A critical examination of these reports[64] revealed that they fall into one of three categories: (1) evidence suggests that flow behind pipe or fractures or fracture-like features were the actual cause of the "coning," (2) results were not convincing that the treatment reduced the water/oil ratio, gas/oil ratio, or water/gas ratio, or (3) insufficient evidence was presented to determine whether the problem was caused by three-dimensional coning, flow behind pipe, or flow through fractures or fracture-like features.

Shell's (PDO) experience in the Marmul field provides an interesting exception to the above observations.[65] Five of fourteen gel treatments were quite successful in reducing the water cut—up to 45% in one case. Convincing evidence was presented that flow behind pipe and fracture-like features were not important. Gelant (0.4% to 0.5% cationic polyacrylamide with glyoxal as a crosslinker) was bullheaded into the wells, using 700 to 2,500 bbls per treatment (11 to 19 bbls per ft in gravel packed completions). The key question is, why were five of the treatments successful, when basic reservoir engineering calculations indicate a very low probability for success for gel treatments in three-dimensional coning applications? The answer may be tied to two special characteristics of this field. First, Shell's simulation work suggests that effective barriers to vertical flow are present.[65] These barriers were not recognized when the first treatments were applied. Second, the oil viscosity was about 80 cp. Thus, viscous fingers of water may have arrived at a given well much earlier in some of the discrete zones than others. Because the oil was much more viscous than the gelant (~10 cp), the gelant may have followed these water fingers and preferentially reduced flow in the water zones to a much greater extent than if a light oil was present. This scenario is consistent with basic reservoir engineering calculations.[14,43] Of course, this scenario suggests that the real problem in this reservoir was not three-dimensional coning, but rather viscous fingering through discrete high permeability pathways. Thus, consistent with our original contention, gelant treatments are not likely to be effective against three-dimensional coning.

Gel treatments are also expected to be ineffective when treating cusping. In cusping, like three-dimensional coning, the well is produced so rapidly that viscous forces overcome gravity forces. For cusping in particular, water from an aquifer follows an inclined zone up to the well. The only practical method to stop water production from the zone (other than decreasing the production rate) is to plug the zone. Unless extraordinary circumstances exist (as in the Marmul case above), hydrocarbon-productive zones in radial flow must be protected during gelant placement. (For the Marmul treatments, one wonders whether the success rate might have been 14/14 instead of 5/14 if hydrocarbon zones had been protected during gelant placement.)

Injector-Producer Channeling in Unfractured Reservoirs with Crossflow (Problem 13). Gelant and gel treatments are expected to be ineffective for treating injector-producer channeling in unfractured reservoirs where fluids can crossflow between zones.[19] For many years, engineers recognized that near wellbore blocking agents are ineffective in these applications.[66] Even if the blocking agent could be confined only to the high permeability channel, water quickly cross flows around any relatively small plug. The only hope for blocking agents in these applications exists if a very large plug (i.e., that plugs most of the channel) can be selectively placed only in the high permeability zone.[66] Unfortunately, existing gelants (including the so-called "colloidal dispersion gels") enter and damage all open zones in accordance with the Darcy equation and basic reservoir engineering principles.[19] Penetration and damage caused to the less-permeable zones is greater for viscous gelants than for low-viscosity fluids. Also, penetration and damage caused to the less-permeable zones is greater when crossflow can occur than when crossflow cannot occur.[19] Although an admirable attempt was made to devise a sophisticated process where gelant treatments might be effective in treating this type of problem,[67,68] traditional polymer floods provide a more cost-effective and reliable solution.[19,69-71]

Conclusions

1. When addressing excess water production problems, the easiest problems should be attacked first, and diagnosis of water production problems should begin with information already at hand. To facilitate implementation of this strategy, a prioritization of water production problems was provided (Table 1).
2. Conventional methods (e.g., cement, mechanical devices) normally should be applied first to treat the easiest problems—i.e., casing leaks and flow behind pipe where cement can be placed effectively and unfractured wells where flow barriers separate water and hydrocarbon zones.
3. Gelant treatments normally are the best option for casing leaks and flow behind pipe with flow restrictions that prevent effective cement placement.
4. Both gelants and preformed gels have been successfully applied to treat hydraulic or natural fractures that connect to an aquifer.
5. Treatments with preformed or partially formed gels normally are the best option for faults or fractures crossing a deviated or horizontal well, for a single fracture causing channeling between wells, or for a natural fracture system that allows channeling between wells.
6. Gel treatments should not be used to treat the most difficult problems—i.e., three-dimensional coning, cusping, or channeling through strata with crossflow.

Nomenclature

F_{rr} = residual resistance factor
h = height, ft [m]
k = permeability, darcys [μm^2]
k_{gas} = permeability to gas, darcys [μm^2]
k_o = permeability to oil, darcys [μm^2]
k_w = permeability to water, darcys [μm^2]
L = distance along a fracture, ft [m]
L_{gel} = distance of gel penetration along a fracture, ft [m]
L_f = fracture length, ft [m]
Δp = pressure drop, psi [Pa]
Δp_{gel} = pressure drop during gel injection, psi [Pa]
Δp_{water} = pressure drop during water injection, psi [Pa]
dp/dl = pressure gradient, psi/ft [Pa/m]
q = total injection or production rate, BPD [m^3/d]
r_e = external drainage radius, ft [m]
r_{gel} = radius of gel penetration, ft [m]
r_w = wellbore radius, ft [m]
S_{or} = residual oil saturation
t = time, days
w_f = fracture width, in. [m]
μ = viscosity, cp [mPa-s]

Acknowledgments

Financial support for this work is gratefully acknowledged from the National Petroleum Technology Office of the United States Department of Energy, BP-Amoco, Chevron, China National Petroleum Corp., Chinese Petroleum Corp., Marathon, Shell, and Texaco.

References

1. "Profile of the Oil and Gas Extraction Industry," EPA/310-R-99-006 (Oct. 1999) 38.
2. Bailey *et al.*: "Water Control," *Oilfield Review* **12** (Spring 2000) 30-51.
3. Elphick, J. and Seright, R.S.: "A Classification of Water Problem Types," Paper 1 presented at the 1997 PNC 3rd International Conference on Reservoir Conformance, Profile Control, Water and Gas Shut Off, Houston, Aug. 6.
4. Seright, R.S. and Liang, J.: "A Survey of Field Applications of Gel Treatments for Water Shutoff," paper SPE 26991 presented at the 1994 SPE III Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina, April 27-29.
5. Chou, S.I. *et al.*: "Development of Optimal Water Control Strategies," paper SPE 28571 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, Sep. 25-28.
6. Pappas, J., Creel, P., and Crook, R.: "Problem Identification and Solution Method for Water Flow Problems," paper SPE 35249 presented at the 1996 Permian Basin Oil & Gas Recovery Conference, Midland, March 27-29.
7. Fulleylove, R.J. *et al.*: "Water Shut-Off in Oil Production Wells—Lessons from 12 Treatments," paper SPE 36211 presented at the 1996 International Petroleum Exhibition and Conference, Abu Dhabi, Oct. 13-16.
8. Lane, R.H.: "Field Operational and Performance Issues of Polymeric Water Control Agents," paper SPE 37243 presented at the 1997 SPE International Symposium on Oilfield Chemistry, Houston, Feb. 18-21.
9. Sydansk, R.D. and Southwell, G.P.: "More Than 12 Years' Experience With a Successful Conformance-Control Polymer-Gel Technology," *SPEPF* **15** (4) (Nov. 2000) 270-278.
10. Love, T. *et al.*: "Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance," paper SPE 49201 presented at the 1998 SPE Annual Technical Conference and Exhibition, New Orleans, Sep. 27-30.
11. Hild, G.P. and Wackowski, R.K.: "Reservoir Polymer Gel Treatments To Improve Miscible CO_2 Flood," *SPEREE* (April. 1999) 196-204.
12. Mennella, A. *et al.*: "Candidate and Chemical Selection Rules for Water Shutoff Polymer Treatments," paper SPE 54736 presented at the 1999 SPE European Formation Damage Conference, The Hague, May 31-June 1.
13. Soliman, M.Y. *et al.*: "Integration of Technology Supports Preventive Conformance Reservoir Techniques," paper SPE 62553 presented at the 2000 SPE/AAPG Western Regional Meeting, Long Beach, June 19-23.
14. Seright, R.S.: "Placement of Gels to Modify Injection Profiles," paper SPE/DOE 17332 presented at the 1988 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, April 17-20.
15. Aguilar, R.: *Naturally Fractured Reservoirs*, Pennwell, Tulsa (1980).
16. Wagner, O.R.: "The Use of Tracers in Diagnosing Interwell Reservoir Heterogeneities—Field Results," *JPT* (Nov. 1977) 1410-1416.
17. Datta-Gupta, A., Vasco, D.W., and Long, J.C.S.: "Sensitivity and Spacial Resolution of Transient Pressure and Tracer Data for Heterogeneity Characterization," paper SPE 30589 presented at the 1995 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 22-25.
18. Smith, L.R., Fast, C.R., and Wagner, O.R.: "Development and Field Testing of Large Volume Remedial Treatments for Gross Water Channeling," *JPT* (Aug. 1969) 1015-1025.

19. Sorbie, K.S. and Seright, R.S.: "Gel Placement in Heterogeneous Systems with Crossflow," paper SPE 24192 presented at the 1992 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.
20. Chan, K.S.: "Water Control Diagnostic Plots," paper SPE 30775 presented at the 1995 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 22-25.
21. Seldal, M.: "Using Water/Oil Ratios to Diagnose Excessive Water Production Mechanisms," Master of Science Thesis, New Mexico Institute of Mining and Technology (May 1997).
22. Seright, R.S.: "Improved Methods for Water Shutoff," Annual Technical Progress Report (U.S. DOE Report DOE/PC/91008-4), U.S. DOE Contract DE-AC22-94PC91008, BDM-Oklahoma Subcontract G4S60330 (Nov. 1997).
23. Marca, C.: "Remedial Cementing" in *Well Cementing, Developments in Petroleum Science* **28** (1990), E.B. Nelson, ed., Elsevier, Amsterdam, 13-1.
24. Meek, J.W. and Harris, K.L.: "Repairing Casing Leaks Using Small-Particle-Size Cement," paper IADC/SPE 21972 presented at the 1991 IADC/SPE Drilling Conference, Amsterdam, March 11-14.
25. Macrae, J.: "Zero Extrusion Casing Patch," paper SPE 37650 presented at the 1997 IADC/SPE Drilling Conference, Amsterdam, March 4-6.
26. Urdahl, H. *et al*.: "Experience with Temporarily Sealing Leaking Tubing Annuli With Extended-Life Polymer Gel Plugs in the Greater Ekofisk Area," paper SPE 24982 presented at the 1992 European Petroleum Conference, Cannes, France, Nov. 16-18.
27. Creel, P. and Crook, R.: "Gels, Monomer Solutions Fix Pinhole Casing Leaks," *Oil & Gas J.* (Oct. 13, 1997) 44-46.
28. Jurinak, J.J. and Summers, L.E.: "Oilfield Applications of Colloidal Silica Gel," *SPEPE* (Nov. 1991) 406-412.
29. Seright, R.S.: "Effect of Rock Permeability on Gel Performance in Fluid-Diversion Applications," *In Situ* (1993) **17**(4), 363-386.
30. Krishnan, P. *et al*.: "Dehydration and Permeability of Gels Used in In-Situ Permeability Modification Treatments," paper SPE 59347 presented at the 2000 SPE/DOE Improved Oil Recovery Symposium, Tulsa, April 3-5.
31. Sydansk, R.D.: "Acrylamide-Polymer/Chromium(III)-Carboxylate Gels for Near Wellbore Matrix Treatments," *SPE Advanced Technology Series* (April 1993) **1** (1), 146-152.
32. Whitney, D.D., Montgomery, D.W., and Hutchins, R.D.: "Water Shutoff in the North Sea: Testing a New Polymer Gel System in the Heather Field, UKCS Block 2.5," *SPEPF* (May 1996) 108-112.
33. Perez, D. *et al*.: "Applications of a Polymer Gel for Establishment of Zonal Isolations and Water Shut-Off in Carbonate Formation," paper SPE 37622 presented at the 1997 SPE/IADC Drilling Conference, Amsterdam, March 4-6.
34. Seright, R.S.: "Gel Propagation Through Fractures," paper SPE 59316 presented at the 2000 SPE/DOE Improved Oil Recovery Symposium, Tulsa, April 3-5.
35. Lai, Q.J. *et al*.: "Gel-Cement Combination Squeezes for Gas Shutoff," paper SPE 54596 presented at the 1999 SPE Western Regional Meeting, Anchorage, May 26-28.
36. Sanders, G.S., Chambers, M.J., and Lane, R.H.: "Successful Gas Shutoff With Polymer Gel Using Temperature Modeling and Selective Placement in the Prudhoe Bay Field," paper SPE 28502 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 25-28.
37. Plahn, S.V. *et al*.: "A Novel Dual Injection System for Water Shut-Off Treatments," *SPEPF* (Nov. 1998) 243-249.
38. Bergem, J. *et al*.: "Successful Water Shutoff in a High-Temperature, High-Volume Producer—A Case History from the Ula Field, Offshore Norway," paper SPE 38833 presented at the 1997 Annual Technical Conference and Exhibition, San Antonio, Oct. 5-8.
39. Seright, R.S.: "Improved Methods for Water Shutoff," DOE Report DOE/PC/91008-1, Contract No. DE-AC22-94PC91008, BDM-Oklahoma Subcontract No. G4S60330, U.S. Department of Energy (Aug. 1997) 8-10.
40. Martins, J. P. *et al*: "Produced Water Reinjection and Fracturing in Prudhoe Bay," *SPERE* (Aug. 1995) 176-182.
41. Paige, R. W. and Murray, L. R.: "Re-Injection of Produced Water – Field Experience and Current Understanding," Eurock '94 (1994) Delft, Netherlands 731-738.
42. Zaitoun, A., Kohler N., and Guerrini, Y.: "Improved Polyacrylamide Treatments for Water Control in Producing Wells," *JPT* (July 1991) 862-867.
43. Liang, J., Lee, R.L., and Seright, R.S.: "Placement of Gels in Production Wells," *SPEPF* (Nov. 1993) 276-284; *Trans.* AIME **295**.
44. Seright, R.S. and Martin, F.D.: "Impact of Gelation pH, Rock Permeability, and Lithology on the Performance of a Monomer-Based Gel," *SPERE* (Feb. 1993) 43-50.
45. Seright, R.S., Liang, J., and Seldal, M.: "Sizing Gelant Treatments in Hydraulically Fractured Production Wells," *SPEPF* (Nov. 1998) 223-229.
46. Seright, R.S., Liang, J., and Sun, H.: "Gel Treatments in Production Wells with Water Coning Problems," *In Situ* (1993) **17**(3), 243-272.
47. Moffitt, P.D.: "Long-Term Production Results of Polymer Treatments in Production Wells in Western Kansas," *JPT* (April 1993) 356-62.
48. Kintzele, M.J.: "Polymer Treatments Brighten Production Profiles of Rocky Mountain Wells," *American Oil & Gas Reporter* (Feb. 1998) 108-119.
49. Sydansk, R.D. and Moore, P.E.: "Gel Conformance Treatments Increase Oil Production in Wyoming," *Oil & Gas J.* (Jan. 20, 1992) 40-45.
50. Borling, D.C.: "Injection Conformance Control Case Histories Using Gels at the Wertz Field CO_2 Tertiary Flood in Wyoming, USA," paper SPE 27825 presented at the 1994 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 17-20.
51. Lane, R.H. and Sanders, G.S.: "Water Shutoff Through Fullbore Placement of Polymer Gel in Faulted and in Hydraulically Fractured Producers of the Prudhoe Bay Field," paper SPE 29475 presented at the 1995 SPE Production Operations Symposium, Oklahoma City, April 2-4.
52. Seright, R.S.: "Gel Placement in Fractured Systems," *SPEPF* (Nov. 1995) 241-248.
53. Lane, R.H., and Seright, R.S.: "Gel Water Shutoff in Fractured or Faulted Horizontal Wells," paper CIM/SPE 65527 presented at the 2000 SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology held in Calgary, Nov. 6-8.
54. Tester, J.W., Bivins, R.L., and Potter, R.M.: "Interwell Tracer Analyses of a Hydraulically Fractured Granitic Geothermal Reservoir," *SPEJ* (Aug. 1982) 537-554.
55. Seright, R.S. and Lee, R.L.: "Gel Treatments for Reducing Channeling Through Naturally Fractured Reservoirs," *SPEPF* (Nov. 1999) 269-276.
56. Merrill, L. S.: "Fiber Reinforced Gel for Use in Subterranean Process Treatment Process," U.S. Patent No. 5,377,760 (1995).

57. Tank, W. J.: "Short Radius Horizontal Drainhole Development and Application in the Yates Field Unit, Pecos County, Texas," MS Thesis, The University of Texas at Austin, Austin, TX (1994).
58. Sydansk, R. D.: "Wellbore Cementing Process Using a Polymer Gel," U.S. Patent No. 4,724,906 (1988).
59. Seright, R.S: "Mechanism for Gel Propagation Through Fractures," paper SPE 55628 presented at the 1999 SPE Rocky Mountain Regional Meeting, Gillette, May 15-18.
60. O'Brien, W.J., Stratton, J.J., and Lane, R.H.: "Mechanistic Reservoir Modeling Improves Fissure Treatment Gel Design in Horizontal Injectors, Idd El Shargi North Dome Field, Qatar", paper SPE 56743 presented at the 1999 SPE Annual Technical Conference and Exhibition, Houston, Oct. 5-8.
61. Seright, R.S: "Polymer Gel Dehydration During Extrusion Through Fractures," *SPEPF* (May 1999) 110-116.
62. Tweidt, L.I. *et al*.: "Improving Sweep Efficiency in the Norman Wells Naturally Fractured Reservoir Through the Use of Polymer Gels: A Field Case History", paper SPE 38901 presented at the 1997 SPE Annual Technical Conference and Exhibition, San Antonio, Oct. 4-6.
63. Southwell, G.P. and Posey, S.M.: "Applications and Results of Acrylamide-Polymer/Chromium(III) Carboxylate Gels," paper SPE 27779 presented at the 1994 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 17-20.
64. Seright, R.S.: "Using Chemicals to Optimize Conformance Control in Fractured Reservoirs," Annual Technical Progress Report (U.S. DOE Report DOE/BC/15110-2), U.S. DOE Contract DE-AC26-98BC15110, (Sept. 1999) 67-75.
65. Faber. M.J. *et al.*: "Water Shut-Off Field Experience with a Relative Permeability Modification System in the Marmul Field (Oman)," paper SPE 39633 presented at the 1998 SPE/DOE Improved Oil Recovery Symposium, Tulsa, April 19-22.
66. Root, P.J. and Skiba. F.F.: "Crossflow Effects During an Idealized Displacement Process in a Stratified Reservoir," *SPEJ* (1965) 229-237.
67. Fletcher, A.J.P. *et al.*: "Deep Diverting Gels for Very Cost-Effective Waterflood Control," *J. Polym. Sci. & Eng.* (April 1992) 7(1-2) 33-43.
68. Kvanvik, B.A. *et al.*: "An Evaluation of Stable Gel Systems for Deep Injector Treatments and High-Temperature Producer Treatments," presented at the 8th European IOR Symposium, Vienna, Austria, May 15-17, 1995
69. Maitin, B.K.: "Performance Analysis of Several Polyacrylamide Floods in North German Oil Fields, paper SPE 21118 presented at the 1992 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-24.
70. Koning, E.J.L., Mentzer, E., and Heemskerk, J.: "Evaluation of a Pilot Polymer Flood in the Marmul Field, Oman," paper SPE 18092 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.
71. Wang, Demin *et al.*: "Commercial Test of Polymer Flooding in Daqing Oil Field," paper SPE 29902 presented at the 1995 SPE International Meeting on Petroleum Engineering, Beijing, Nov. 14-17.

SI Metric Conversion Factors

bbl x 1.589 873	E-01	= m^3
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—Excess Water Production Problems and Treatment Categories
(Categories are listed in increasing order of treatment difficulty)

Category A: "Conventional" Treatments Normally Are an Effective Choice
1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.

Category B: Treatments with Gelants Normally Are an Effective Choice
4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

Category C: Treatments with Preformed Gels Are an Effective Choice
8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

Category D: Difficult Problems Where Gel Treatments Should Not Be Used
11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

Table 2—Water Shutoff Materials and Methods

Chemical & Physical Plugging Agents	Mechanical & Well Techniques
cement, sand, calcium carbonate	packers, bridge plugs, patches
gels, resins	well abandonment, infill drilling
foams, emulsions, particulates, precipitates, microorganisms	pattern flow control
polymer/mobility-control floods	horizontal wells

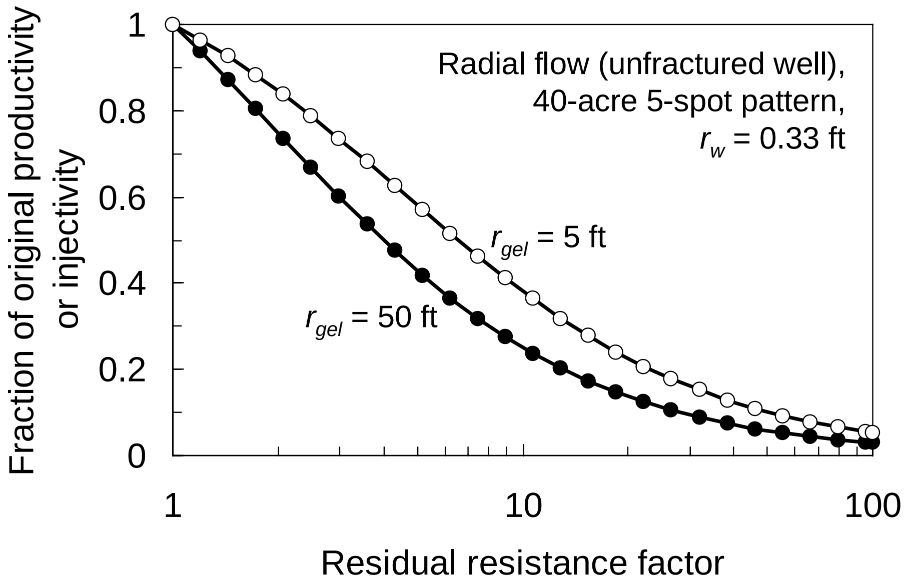

Fig. 1—Fraction of original injectivity or productivity retained versus residual resistance factor.

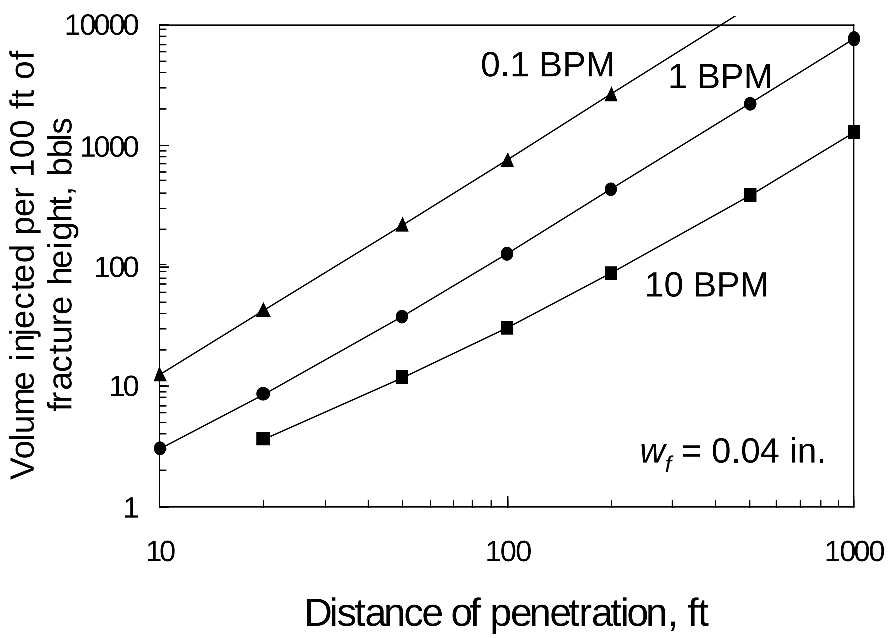

Fig. 2—Gel propagation predictions in long two-wing fractures. Fracture width = 0.04 in.

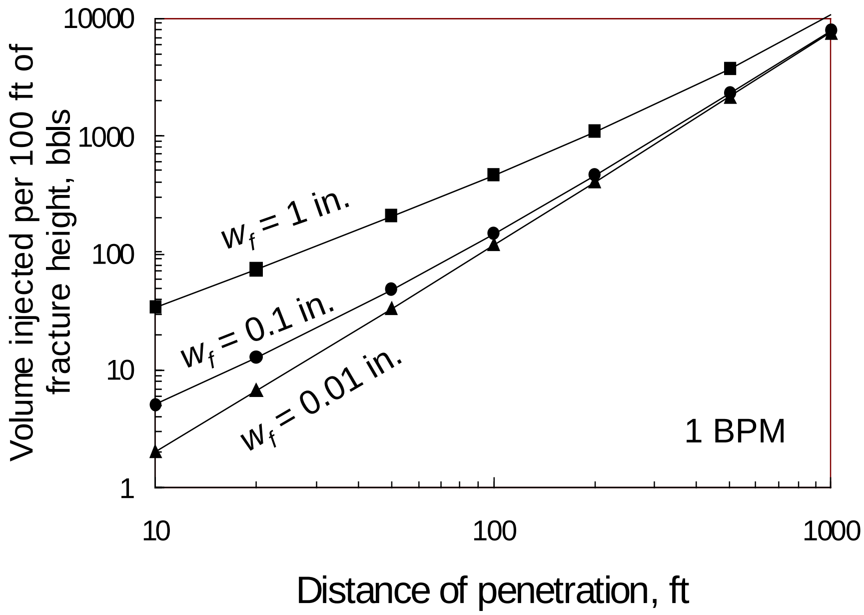

Fig. 3—Gel propagation predictions in long two-wing fractures. Injection rate = 1 BPM.