

A Strategy for Attacking Excess Water Production

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Summary

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 that diagnosis of water production problems should begin with the information already at hand. A listing of water-production problems is provided, along with a ranking of their relative ease of solution. Although a broad range of water-shutoff technologies is considered, the major focus of the paper is when and where gels can be effectively applied for water shutoff.

Introduction

In the United States, on average, 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 U.S. \$5–10 billion and approximately \$40 billion worldwide.²

Many different causes of excess water production exist (see **Table 1**). Each problem 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 first must be identified correctly.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 problems. Again, for effective treatment, the nature of the problem first must be identified correctly.

Four problem categories are listed in Table 1 in the general order of increasing treatment difficulty. Within each category, the listing order 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, use 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, describes a leak occurring through a large aperture breach in the piping (greater than roughly $\frac{1}{8}$ in.) and a large flow conduit (greater than roughly $\frac{1}{16}$ in.) behind the leak. The use of Portland cement is favored for treating Problem 1. Problem 4, involving casing leaks with flow restrictions, is when the leak occurs through a small aperture breach (e.g., “pinhole” and thread leaks) in the piping (less than roughly $\frac{1}{8}$ in.) and a small flow conduit (less than roughly $\frac{1}{16}$ in.) behind the leak. Gel is favored to successfully treat Problem 4. In this paper, the gels under discussion may include those formed from chemically crosslinked water-soluble organic polymers, water-based organic monomers, or silicates.

The difference between Problems 2 and 5 again is simply a matter of aperture size of the flow channel behind the pipe. Problem 2, involving flow behind pipe without flow restrictions, refers to fluid flow occurring through a large aperture flow conduit behind the pipe (greater than roughly $\frac{1}{16}$ in.). 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, describes flow behind pipe occurring through a small aperture flow conduit (less than roughly $\frac{1}{16}$ in.). Gel is favored to treat this problem. Problem 5 is often exemplified by microannuli flow behind the pipe. This problem often results from cement shrinkage while curing during the well’s completion.

The recognition, importance, challenge, and necessity of successfully treating Problems 2 and 5 recently have become much more prominent 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., 3D 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.^{2–14} A common theme of many of these papers is the need for proper diagnosis of the excess-water-production problem. However, for the reasons mentioned previously, such diagnosis frequently is 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 forgo problem diagnosis and, in turn, implement ineffective water-shutoff treatments.

Proposed Strategy

Our proposed strategy for attacking excess-water-production problems advocates that the easiest problems should be attacked first and that 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, as shown in Table 1. The first three listings are the easiest problems (Category

TABLE 1—EXCESS WATER PRODUCTION PROBLEMS AND TREATMENT CATEGORIES	
(Categories are listed in increasing order of treatment difficulty.)	
Category A: “Conventional” Treatments are Normally 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.	“2D 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 for Which Gel Treatments Should Not be Used	
11.	3D coning.
12.	Cusping.
13.	Channeling through strata (no fractures), with crossflow.

A, Problems 1 through 3), and their successful treatment generally has 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 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.

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

In contrast, the last three problems (Category D, Problems 11 through 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 through 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 with gels. As will be discussed shortly, Problems 4 through 7 (Category B in Table 1) normally are best solved using gelants (i.e., the fluid gel formulation before significant crosslinking occurs). Problems 8 through 10 (Category C) are best solved with 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 3D coning (Problem 11 in Table 1) caused the problem, whereas a small amount of subsequent diagnosis and analysis revealed that the true source of water production was either flow

behind pipe (Problem 2) or “2D coning” through a fracture (Problem 6). This knowledge could have substantially reduced the cost of solving the problem (because 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 following order.

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 vs. time may show an abrupt increase in the 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 coproduced 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 decrease correspondingly. The second type of water production competes directly 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,

TABLE 2—WATER SHUTOFF MATERIALS AND METHODS	
Chemical and Physical Plugging Agents	Mechanical and 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

the second type of water production should be the target of water-shutoff treatments.

Understanding and conceptualizing the reservoir “plumbing” is a key to:

- Distinguishing between the previous two types of water production.
- Successfully diagnosing the water production problem.
- 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 that the water is produced via a flow path separate from that of the oil, the operator should ask whether the excess-water-production is caused by a relatively easy problem (as listed in Table 1), particularly by unrestricted casing leaks or by flow behind pipe. Some of the common methods used to diagnose these problems include:

- Leak tests/casing integrity tests (e.g., hydrotesting).
- Temperature surveys.
- Flow profiling tools (e.g., radiotracer flow logs, spinner surveys, production logging tools).
- Cement bond logs.
- Borehole viewers.
- Noise logs.

Refs. 15 and 16 provide detailed descriptions of these methods.

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 previously listed 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 desired properties of the blocking agent, volume of blocking agent placed, and 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 in 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 with the Darcy equation reveal that the approach for solving these linear flow problems must be fundamentally different from solving radial flow problems in matrix reservoir rock or sand.¹⁷ Especially for gel treatments, linear vs. radial flow problems differ radically in gel properties desired, placement procedures required, and optimum volume of the gel placed. In particular, hydrocarbon productive zones *must* be protected during gelant placement for radial flow problems.¹⁷ For linear flow, an acceptable gel placement (without mechanically isolating zones) is much easier to achieve than with 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 method⁴ uses the Darcy equation for radial flow.

$$q/\Delta p = \Sigma kh/[141.2 \mu \ln (r_e/r_w)]. \dots\dots\dots (1)$$

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 with 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:

$$q/\Delta p \gg \Sigma kh/[141.2 \mu \ln (r_e/r_w)]. \dots\dots\dots (2)$$

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:

$$q/\Delta p \leq \Sigma kh/[141.2 \mu \ln (r_e/r_w)]. \dots\dots\dots (3)$$

In the previous equation, k = 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 , is measured in cp. If the well is a water injector or 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 with 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. Because the calculations are easily performed with 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 previously, 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 core and log analyses (especially from highly deviated or horizontal wellbores), pulse tests/pressure transient analyses, and interwell tracer studies.

Various logging methods have been used to detect and characterize fractures (see Chap. 3 of Ref. 18). However, these methods must be used with caution because 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 often have been used to characterize fractured reservoirs (see Chap. 4 of Ref. 18). Reportedly, these methods can estimate the fracture volume; the fracture permeability; and, 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 indices also were 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.^{19,21} Interwell tracer data provide much better resolu-

tion of reservoir heterogeneities than pressure transient analyses.²⁰ Tracer results can indicate the following.

- Whether fractures or fracture networks are probably present and if those fractures are the cause of a channeling problem.
- The location and direction of fracture channels.
- The fracture volume.
- The fracture conductivity.
- The effectiveness of a remedial treatment (e.g., a gel treatment) in reducing channeling.²¹

For operators producing from mature, highly fractured oil reservoirs, low-cost and operationally easy tracer techniques exist that can help diagnose excess-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.²² Even if gelant is injected only 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.²² 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.¹⁷

Several methods are used to assess whether crossflow exists between strata, including pressure tests between zones; various logs for determining fluid saturations, permeability, porosity, and lithology; injection/production profiles; simulation; and seismic methods. The most straightforward method tests pressure differences between zones. A packer is commonly 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 can occur. If the operator does not know whether crossflow occurs, he should assume that crossflow exists. Ref. 23 describes an interesting case in which pressure testing was used to assess the presence of crossflow.

WOR History Plots. Plots of the WOR vs. time can provide a valuable indication of when an excess-water problem develops.^{2,24} Along with other information, such plots also can aid in identifying the cause of the problem. However, these “diagnostic plots” (of WOR or WOR-derivative vs. time) should not be used alone to diagnose excess-water-production mechanisms and problems.^{25,26} 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.²⁴ According to this method, gradually increasing WOR curves with negative derivative slopes are unique to 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 (fracture or flow behind pipe) and radial flow for either channeling or coning. As mentioned previously, the linear/radial distinction is extremely important—much more so than whether the problem is caused by generic channeling or coning.

Recently, reservoir models were built for water coning and channeling, respectively, and a sensitivity analysis was performed with numerical simulation.^{25,26} 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 multilayer channeling problems easily could 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 easily can be misinterpreted and, therefore, should 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 choice of treatment method, properties of the conformance or blocking agent, volume of conformance or blocking agent used, and 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 problem type 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^{27,28} or mechanical patches.^{2,29} However, these methods generally have 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 dislodge the cement plug. Gel treatments can be more successful for these applications.^{30–32} 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 flows 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? Because the objective is to achieve total water shutoff from the leak and because 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.^{33,34} Gels for this application often have been formulated with relatively high concentrations (4 to 7%) of acrylamide polymers that have a relatively low molecular weight (on the order of 25,000 to 500,000 daltons).³⁵ Gelants for this application should be of relatively low viscosity and should experience essentially no polymer crosslinking during gel treatment placement.

Refs. 30 through 33 provide field examples in which gels showed superior behavior vs. cement when treating leaks.

Flow Behind Pipe (Problems 2 and 5 in Table 1). Problems with unrestricted flow behind pipe are usually treated with cement.²⁷ 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 microannuli 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, because they can flow or extrude readily through narrow constrictions.^{36–38} The ability of gels to withstand high pressure gradients increases with decreasing channel width.³⁹ 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 gels from washing out from their strategic locations.⁴⁰

When treating flow-behind-pipe problems in which a substantial drawdown pressure (i.e., >100 psi) exists, gelants often are employed rather than preformed or partially formed gels. Three reasons support favoring 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 placement of gelant solutions. Second, gelant invasion into per-

meable 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 wash out 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 microannuli between the primary cement and the formation.

Refs. 36 through 38 provide field examples in which gels showed superior behavior vs. cement when treating flow behind pipe.

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 most commonly used to stop water production. Historically, when the water zone is located above an oil zone, the most common water-shutoff methods include cement or carbonate squeezes (into perforations) or mechanical packers or patches²⁷ (i.e., the conventional treatments of Category A).

However, gels involving gelant injection also have been used frequently to treat these problems.^{7,32,36,41} In these instances, the problem solution falls into Category B of Table 1. Gels have two advantages vs. cements and carbonates for some applications.³⁶ First, gelants can flow into porous rock, whereas cements and particulate blocking agents are filtered out at the rock surface. Cements (including “microfine cement”) will not invade porous rock or sands with normal permeabilities (e.g., sandstone and sands of <10,000 md) to any significant distance unless the porous medium experiences fracturing, parting, or very high pressure gradients. 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 seal sufficiently. In contrast, gels (i.e., after gelation) can form an impermeable rubbery mass that extends past the rock surface and well into the porous rock. Second, gelants and gels can penetrate into and plug narrow channels (e.g., microannuli) behind pipe in the vicinity of the zone to be shut off.³⁶ Therefore, in some cases, gels can provide a more effective seal in the zone to be plugged.

When treating radial flow problems with gels or similar blocking agents, hydrocarbon zones must be protected during gelant placement. Otherwise, the blocking agent probably will also damage the hydrocarbon zones.¹⁷ Mechanical isolation of zones is the most obvious method to protect oil zones during gelant placement. However, other methods exist—notably, dual injection.^{7,23,42} As an example of dual injection, gelant might be injected down coiled tubing into the water zone while nondamaging 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 in which 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 in which laterally extensive barriers (e.g., shale or anhydrite layers) are not present away from the wellbore.²⁶ 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 successful implementation. Refs. 23 and 42 describe field applications of the dual-injection technique.

For gel applications in unfractured injection or production wells in which 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.⁴³ This figure applies to gel treatments in both injection and production 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). This figure 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 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 5-ft radius of penetration often will 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. For typical gelant penetrations in the water zones, 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 in which 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.^{44,45} 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, however, always reduce k_o to some extent. In the best cases, Zaitoun and Kohler⁴⁶ 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.⁴⁷ In other words, this “disproportionate permeability reduction” will not mitigate water production from a reservoir that effectively has only one zone. When a single zone exists, even if the polymer or gel can significantly reduce the 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

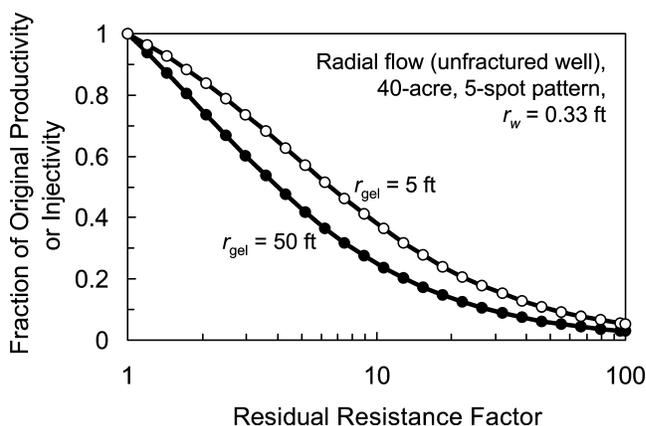


Fig. 1—Fraction of original injectivity or productivity retained vs. residual resistance factor.

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 in oil productivity, even if the polymer or gel reduces k_w , without affecting k_o . This loss of oil productivity will be in direct proportion to the water-productivity loss caused in that particular zone.

A common misconception is that the disproportionate permeability reduction will be of value mainly in treating unfractured production wells in which 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 2, 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, an F_{rr} value of 2 causes a 27% loss in productivity, while an F_{rr} value of 10 causes a 75% loss. Both 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 of less than two may be difficult to achieve in a predictable and controllable manner.^{33,48} Low F_{rro} values usually mean that gelation was incomplete and that 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, which are influenced by the rock lithology and resident fluid composition.^{33,48} 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 is currently 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. Refs. 23, 32, 49, and 50 demonstrate field applications of gel treatments for solving this type of problem.

2D Coning: Hydraulically Fractured Production Wells (Problem 6). When production wells are hydraulically 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 the 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.⁵¹ 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, and 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 in which 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 of 50,000 and 50, respectively. (These properties have been reported for a gel formulation.⁵²) In this case, the gel adds only the equivalent of 10 ft of additional rock that the oil must flow through to enter the fracture (i.e., 0.2 ft \times 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 \times 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 the rock next to the fracture.⁵¹ Ideally, fracture conductivity is not reduced significantly, because 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.⁵¹ However, the method frequently should provide acceptable outcomes, even if crossflow can occur between the water- and oil-bearing zones. For example, consider the case in which oil lies on top of water in a single formation (a common situation in which coning becomes a problem). Previous works^{47,52} 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 we propose 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.^{47,52} 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 coupled with results from two simple laboratory experiments are needed.⁵¹ The necessary field data include:

- Fluid production rates before gel treatment.
- Downhole static and flowing pressures before gel treatment.
- Permeabilities, porosities, and thickness of the relevant zones.
- Water and oil viscosities at reservoir temperature.
- Well spacing or distance between wells.

These parameters often are 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.⁵¹ These experiments must be conducted with 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 in which 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:

- Fluid production rates after the gel treatment.
- Accurate downhole static and flowing pressures after the gel treatment.
- 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 2D 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.^{4,53,54} These treatments were applied to reduce excessive water production emanating via natural fractures from underlying aquifers that provided strong waterdrives.

Phillips applied 37 treatments in Arbuckle formations using eight different organic polymer and polymer-crosslinker combinations.⁵³ 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 pretreatment WOR and oil production rate was 12 months, with a range from 2 to 43 months. The treatments typically reduced the total fluid productivity by a factor of 2. 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 lb/well), the type of polymer or gel treatment (eight types used), the productivity reduction induced by the treatment (1 to 5), the structural position of the completion, completion type, the fluid level before the treatment, or the Arbuckle reservoir.⁵³ (Treatments were applied in several Arbuckle reservoirs.)

A review of 274 water-shutoff treatments 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 1 to 2 years following the treatment. The median oil productivity increased by three shortly after treatment and returned to pretreatment levels after 1 to 2 years.

The positive effects of these treatments were generally short-lived in the Arbuckle and Ellenberger formations. However, for several gel applications in the Madison formation in Wyoming, reductions in the water cut were sustained for many years.⁵⁴ Chromium(III)-carboxylate/acrylamide-polymer gel water-shutoff treatments also were applied to 14 economically marginal production wells of the mature Big Lake field in Texas.⁹ On average, water production was decreased from 3,410 to 993 barrels of water per day (BWPD), and oil production increased, on average, from 2 to 14 barrels of oil per day (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.^{9,55} During successful gel treatments in 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? Is it better to inject gelant, fully formed gels, or partially formed gels, and when and where? 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? Although many of these questions remain to be answered, Ref. 56 describes engineering calculations for determining gel properties, volume requirements, and treatment impact for gelant treatments in the naturally fractured Motatan field in Venezuela.

Individual Fractures That Cause Channeling From Injectors to Producers (Problem 9). Gel treatments currently provide the most effective means to reduce channeling through fractures.^{4,57-59} Except in narrow fractures (i.e., fracture widths of less than 0.02 in.), extruded gels have a placement advantage vs. con-

ventional 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 gravity forces.⁶⁰ 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.⁶⁰ Generally, gelation times cannot be controlled well enough to prevent gravity segregation in the time between gelant injection and gelation.

Alternative to conventional gel treatments, formed (pre-formed) gels can be extruded through fractures. Because these gels are 10^3 to 10^6 times more 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.^{11,57-59}

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.³⁹ Gels concentrate or dehydrate during extrusion through fractures. During flow in a fracture, the dehydration rate for these gels varies inversely with the square root of time. This fact allows gel propagation along fractures to be predicted.^{39,61} [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 more rigid gels that are less likely to wash out 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 penetration distances 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 penetration distance 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.³⁹ 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 the fracture width.³⁹ The volume of gel that can be injected depends critically on fracture width and gel

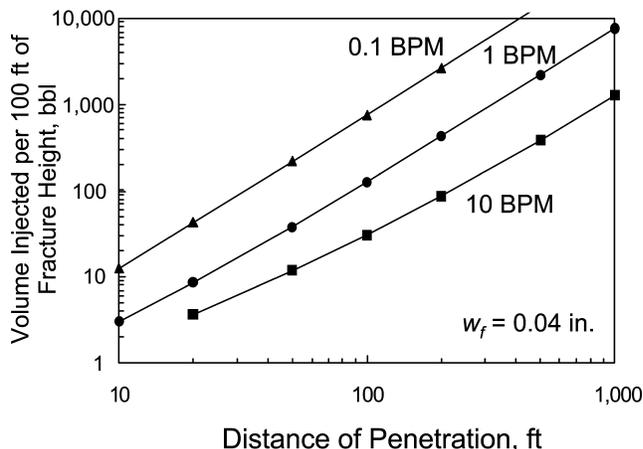


Fig. 2—Gel propagation predictions in long two-wing fractures. Fracture width=0.04 in.

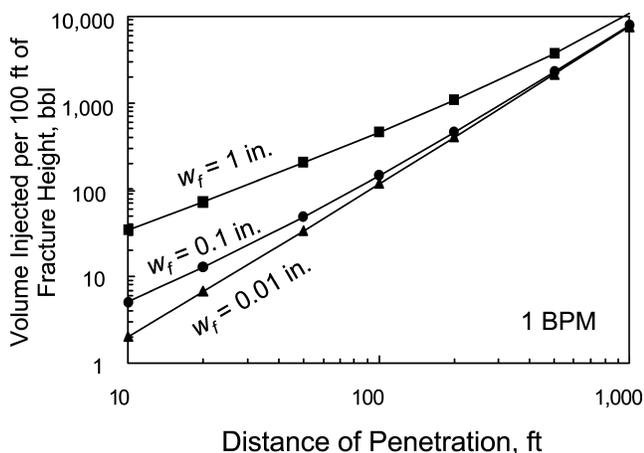


Fig. 3—Gel propagation predictions in long two-wing fractures. Injection rate=1 BPM.

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.³⁹ 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.^{62,63} Tester *et al.*⁶² 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 used to estimate effective average fracture width (*w_f* in inches)⁶³:

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

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

For some applications in which 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.⁶⁴⁻⁶⁶

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.⁵⁹ Often, the completions of these wells severely limit 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 also will 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.^{39,59,61} 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,⁶⁷ 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 often can 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.³⁹) Alternatively, coiled tubing can be used to circulate gel out of the wellbore.³⁶ (In practice, water, oil, or an uncrosslinked polymer solution often is injected immediately after the gel in an attempt to displace gel from the wellbore into the fracture.⁵⁹ Because this displacement is unstable, its effectiveness is questionable.)

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.⁶⁸ In this case, the benefit gained varies approximately logarithmically with the distance of gel penetration.⁶¹ 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, 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 individual 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.⁶¹ The calculations also can give an idea of how far the gel should penetrate to provide a beneficial effect.³⁹ Using laboratory data coupled with field data collected before, during, and after injection of similar gel treatments, the calculations also can give an indication of how far the gel actually penetrated into the fracture.⁶¹ 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.⁶⁹ Because the pressure gradient during gel extrusion is almost independent of injection flux, the pressure gradient is nearly independent of the 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.

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

in which *Δp_{water}* = the pressure drawdown (i.e., the downhole pressure difference between the wellbore and the formation) during water injection, *Δp_{gel}* = the pressure drawdown during gel injection, and *(dp/dl)_{gel}* = 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.³⁹ 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) with Eq. 6.

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

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

Ref. 61 describes the application of the previous methodology and equations for fractures and faults in the Prudhoe Bay field. Refs. 59 and 68 provide additional discussion of field applications

of gel treatments that were directed at faults that crossed deviated or horizontal wells in Prudhoe Bay and Qatar.

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.^{11,55–58,68,70} 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 bbl) of gel was typically greater than the gelation time by a factor around 100.^{11,57,58} Thus, formed gels extruded through fractures during most of the placement process. Several operators reported that oil recovery increased with an increased volume of gel injected per treatment.^{11,57,58} 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.⁶³

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.⁶³ 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 with Eq. 4 from the breakthrough time from an interwell tracer study. Because the ability of a gel to extrude through a fracture depends critically on the fracture width or conductivity,^{39,67,69} 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 to more than 20% of the injected tracer concentration.⁶³ 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.

Ref. 55 discusses a field example in which tracer testing was conducted in conjunction with the application of injection-well chromium(III)-carboxylate/acrylamide polymer (CC/AP) gel treatments to the Tensleep sandstone formation of the Pitchfork Field in Wyoming.

Gel treatments to reduce injector-producer channeling in naturally fractured reservoirs can be applied in either injection or production wells. Well documented field applications involving injector-producer channeling in naturally fractured reservoirs can be found in Refs. 11, 55, 57, 58, and 70.

3D Coning and Cusping (Problems 11 and 12). Gelant or gel treatments have an extremely low probability of success when applied toward cusping or 3D coning problems occurring in unfractured matrix reservoir rock. When treating coning problems, a common misconception is that the gelant will enter only 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 3D coning problems. Extensive numerical studies using a variety of coning models in-

dicating that gel treatments can provide improvement only if the desired production rate is less than 1.5 to 5 times the pretreatment critical rate.^{47,52} This circumstance rarely occurs.

In contrast to the very limited potential of polymers and gels in successfully treating 3D coning, these treatments have much greater potential for successfully treating “2D coning” in which 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 a factor of more than 100 in fractured wells.^{47,52}

A number of literature reports suggested that gel or foam treatments were effective in mitigating 3D coning. A critical examination of these reports⁷¹ revealed that they fall into one of three categories:

- Evidence suggests that flow behind pipe or fractures or fracture-like features were the actual cause of the “coning.”
- Results were not convincing that the treatment reduced the WOR, gas/oil ratio, or water/gas ratio.
- Insufficient evidence was presented to determine whether the problem was caused by 3D coning, flow behind pipe, or flow through fractures or fracture-like features.

The experience of Shell/Petroleum Development Oman in the Marmul field provides an interesting exception to the previous observations.⁷² Out of 14 gel treatments, 5 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 bbl per treatment (11 to 19 bbl 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 3D 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.⁷² These barriers were not recognized when the first treatments were applied. Second, the oil viscosity was approximately 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.^{17,47} Of course, this scenario suggests that the real problem in this reservoir was not 3D coning, but rather viscous fingering through discrete high-permeability pathways. Thus, consistent with our original contention, gelant treatments are unlikely to be effective against 3D coning.

Gel treatments also are expected to be ineffective when treating cusping. In cusping, like 3D 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 previous Marmul case), 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.²² For many years, engineers recognized that near-wellbore blocking agents are ineffective in these applications.⁷³ Even if the blocking agent could be confined only to the high permeability channel, water quickly crossflows 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.⁷³ Unfortunately, existing gels (including the so-called “colloidal dispersion gels”) enter and damage all open zones in accordance with the Darcy equation and basic reservoir-engineering principles.²² Penetration and damage caused to the less-permeable zones is greater for viscous gels 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.²² Although an admirable attempt was made to devise a sophisticated process in which gelant treatments might be effective in treating this type of problem,^{74,75} traditional polymer floods provide a more cost-effective and reliable solution.^{22,76–79} Refs. 76 through 79 provide illustrative examples of polymer floods in various fields throughout the world.

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 and 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 are normally the best option for casing leaks and flow behind pipe with flow restrictions that prevent effective cement placement.
4. Both gels 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 are normally 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., 3D coning, cusping, or channeling through strata with crossflow).

Nomenclature

- dp/dl = pressure gradient, psi/ft (Pa/m)
 F_{rr} = residual resistance factor
 F_{rro} = oil 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_f = fracture length, ft (m)
 L_{gel} = distance of gel penetration along a fracture, ft (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)
 Δp = pressure drop, psi (Pa)
 Δp_{gel} = pressure drop during gel injection, psi (Pa)
 Δp_{water} = pressure drop during water injection, psi (Pa)
 μ = viscosity, cp ($\text{mPa}\cdot\text{s}$)

Acknowledgments

Financial support for this work is gratefully acknowledged from the Natl. Petroleum Technology Office and NETL of the U.S. Dept. of Energy, BP plc, ChevronTexaco, China Natl. Petro-

leum Corp., Chinese Petroleum Corp., ConocoPhillips, Marathon, and Shell.

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SI Metric Conversion Factors

acre × 4.046 873	E+03 = m ²
bbl × 1.589 873	E–01 = m ³
cp × 1.0*	E–03 = Pa·s
ft × 3.048*	E–01 = m
in. × 2.54*	E+00 = cm
lbm × 4.535 924	E–01 = kg
psi × 6.894 757	E+00 = kPa

*Conversion is exact.

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