Determination of Maximum Injection Pressure for Class I Wells

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL SECTION REGIONAL GUIDANCE #7

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Contents

Region 5 advises that maximum injection pressures for Class I injection wells in the Region should be less than or equal to the measured fracture closure pressure of the injection interval. If the injection interval pressure remains below fracture closure pressure, any existing fractures cannot open, no new fractures can form, and therefore neither can transmit fluids out of the injection interval.

PART I. RATIONALE

The Regulatory Standard

Underground Injection Control regulations promulgated in response to requirements of the Safe Drinking Water Act include 40 CFR 146.13(a) for non-hazardous waste wells and 146.67(a) for hazardous waste wells, which state that:

Except during stimulation, the owner or operator shall assure that injection pressure at the wellhead does not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone.

Well stimulation in which the injection zone is subjected to controlled fracturing (fracture treatment) is allowed by regulation because of its capacity in some geologic settings to increase injectivity. Fracture treatments produce fractures of limited extent with permanent apertures; that is, they remain transmissive when the pressure which formed them is relieved. In this situation, fracturing is not an environmental concern, whereas uncontrolled fracturing caused by excessive waste injection pressures is of great concern.

The regulations cited above do not address the effects of transmissive fractures which may exist in the injection or confining zones prior to injection activities; other regulations address this situation (e.g. 40 CFR 144.12, 146.12, and 146.62).

Background

In some regions of the United States, fracturing the injection or confining zones may be a very unlikely occurrence because the minimum in-situ stress or the transmissivity of injection zones is uniformly high. Neither is the case in most of Region 5, where both the tectonic regime and the thickness and permeability of injection zones vary widely. Here fracturing can be a more immediate concern.

Region 5 previously used a fracture pressure gradient of 0.80 psi/ft for calculating MIPs for Class I permits in the Direct Implementation States of Michigan and Indiana, unless a lower pressure resulted in sufficient injectivity. The State of Ohio has used a maximum pressure gradient of 0.75 psi/ft for MIP calculations. The State of Illinois has set MIPs on a case-by-case basis; all are presently less than 0.60 psi/ft.

Data have become available in Region 5 which indicate that the practice of assuming a uniform fracture gradient is not appropriate in Region 5. Site-specific fracture closure pressure, or data from which it can be derived, are available currently for formations used for injection by Class I wells for sites spread through Michigan, Ohio, and Indiana. These data show that actual fracture closure pressure gradients range from 0.48 to 0.91 psi/ft. It is clear that Region 5's previous practice of using a 0.80 psi/ft gradient for every site was not a sufficient safeguard against initiating and/or propagating fractures at all sites.

Region 5 Policy

Region 5 advises that, except under certain circumstances discussed below, maximum injection pressures (MIPs) for Class I injection wells in the Region should be less than or equal to measured fracture closure pressure of the injection interval at the site. Closure pressure has been selected for two reasons: (1) it provides a conservative safety factor--closure pressure will preclude any fractures from opening--if fractures are not opened, they cannot propagate and thus transmit waste fluids out of the injection zone: and (2) it is susceptible to calculation utilizing standardized, ASTM-approved testing methods.

Region 5 recognizes that operation at pressures above fracture closure pressure will not always lead to propagation of fractures and has taken account of this in its implementation of this guidance. However, fracture opening can be an environmental concern if the pre-existing fractures are large, if the opening allows waste to enter other transmissive pathways (such as an open natural fracture system) or if the opening is followed by fracture propagation.

Before issuing the original guidance on this subject in 1992, Region 5 sent a draft to State agencies and a cross-section of Class I injection well operators and their consultants in the region, to inform them of this evolution in the Region's thinking about maximum injection pressures and to gather feedback on the new Regional policy. Few comments were received and many of these were incorporated into the final guidance.

Implementation

This Regional Guidance is currently being implemented through Underground Injection Control permits for new and existing wells issued by Region 5. The Region strongly encourages concurrent implementation in Primacy States and will carefully review any Primacy State actions which employ another approach. However, Region 5 recognizes that primacy states may employ different approaches, and Region 5 will accept maximum injection pressures lawfully approved by primacy states in accordance with any one of the three methods set forth in this guidance, subject to EPA's oversight authority pursuant to Section 1422 of the SDWA, 42 U.S.C. &sect 300h-1. In any case where a primacy state has lawfully approved a maximum injection pressure, Region 5 will not require any further demonstration from an operator, subject to EPA's oversight authority pursuant to Section 1422 of the SDWA, 42 U.S.C. &sect 300h-1. To assure the safety of the well operation, Region 5 also includes a review of maximum injection pressure consistent with this policy in the determinations it makes on whether to issue an exemption to land disposal prohibitions. In implementing this policy within Region 5, operators have available three options:

Option 1: Operators may submit a site-specific fracture closure pressure derived from direct or indirect testing. This is the Region's preferred option. The Region favors direct tests over indirect tests and generally expects them for newly drilled wells.

The Region prefers to use a closure pressure determined by in-situ stress testing for the calculation of MIP, but will accept estimates of closure pressure based on conventional step rate test results or instantaneous shut-in pressure (ISIP) following fracture treatments, as discussed below. The Region will also consider the use of indirect test methods on a case-by-case basis. In general, data from a different facility will not be acceptable unless it is very nearby. An operator may request that a conservative estimate of tubing friction and, if applicable, perforation friction be added when calculating the MIP.

Few data are available which indicate the difference, if any, between step rate test results and fracture closure pressure measured from an in-situ stress test. Lacking such data, Region 5 recommends that, if step rate tests are used to estimate fracture closure pressure, the bottom-hole pressure corresponding to the inflection point be used directly as an estimate of closure pressure (see description of step rate testing, p. 6). Some limited data are available which indicate that closure pressure is, on average, 18 percent less than ISIP converted to a formation-face pressure. Based on these data, Region 5 recommends that, when in-situ stress tests or step rate tests are not available or cannot be performed, a pressure 18 percent less than ISIP be used to estimate fracture closure pressure. If more data become available, these recommendations may be updated.

Option 2: Operators may request that the Region use a formation- and area-specific, conservative, default value for closure pressure established by the Region from tests run in other wells.

In order to decrease the burden of this Regional policy on operators wherever possible, the Region has chosen formation-specific default values for fracture closure pressure gradient for formations where enough site-specific data are available to do so. The default values generally are based on the lowest in-situ measurement of closure pressure. As of the date of this guidance the Region has chosen default values of 0.57 psi/ft for the Mt. Simon Formation and 0.80 psi/ft for the Dundee Limestone. These will be updated if data indicating lower fracture pressure gradients become available, and default values for additional formations and sub-regions, such as basins, may be added. The default values may be used for existing wells, but generally newly drilled wells will be required to obtain site-specific data.

Option 3: Operators may submit data showing that operation at a given pressure, which is above fracture closure pressure, does not initiate or propagate fractures at their site.

Under certain circumstances, operation at a given pressure above fracture closure pressure will not lead to propagation of fractures. Therefore, operators are given the option of providing historical operating data and intensive site studies to show that operation at a given pressure does not lead to propagation of fractures or waste migration out of the injection interval or zone. Operators desirous of utilizing this option are invited to discuss their proposed submission with the Region in advance.

PART II. TERMINOLOGY AND TESTING METHODS

Hydraulic Fracturing Terminology

Key terms relating to hydraulic fracturing, as used by Region 5, are defined briefly below and are illustrated on Figure 1, a plot of pressure change versus time during a fracture treatment. Pressure terms relating to three physical fracture phenomena are addressed in indented paragraphs, followed by a brief discussion. It should be kept in mind that breakdown, fracture propagation, and fracture closure pressures will vary vertically through the injection zone as rock and stress characteristics change.

Fracture initiation: The breaking of intact rock, which occurs along a plane perpendicular to the minimum principal stress (force/area) in the rock.

The pressure necessary to initiate a fracture in intact rock is known as **breakdown pressure**, or **formation fracture pressure (FFP)**. Formation breakdown pressure is a function of the tensile strength of the rock, its pore pressure, and the maximum and minimum horizontal stresses. Breakdown pressure gradients can range from less than 0.4 to over 1.2 psi/ft. The breakdown pressure which is measured at the bore hole can be affected greatly by borehole conditions.

Fractures generally are initiated and propagated along a plane perpendicular to the minimum principal stress. For most Class I sites in Region 5, the vertical stress due to the weight of rock overlying the injection interval is likely to be greater than horizontal stresses resulting from confining and tectonic effects. In such a case, the minimum principal stress is in a horizontal plane and any fractures which are initiated or propagated are in a vertical plane. In tectonically relaxed areas, the vertical stress becomes the least stress at some shallower depth, generally somewhere above 2000 feet, causing fractures to occur horizontally at shallow depths. However, vertical fracturing may still occur in some formations at depths shallower than the deepest point at which the least principal stress is vertical.

Fracture propagation: The extension of an existing fracture. The fracture may have existed for a long time or may have just been created.

Fracture propagation pressure is the minimum pressure at the formation face in the wellbore, which causes extension of a fracture. Some investigators consider the terms **formation parting pressure** and **fracture parting pressure (FPP)** to be equivalent to fracture propagation pressure (e.g., Singh et al., 1987); however, because there may not be general agreement on the meaning of these terms, they are not used in this policy. **Treating pressure** is the wellhead pressure recorded during fracture propagation, and thus changes during a fracture treatment (Figure 1). **Instantaneous shut-in pressure (ISIP)** is the wellhead pressure immediately after pumps are shut down following a fracture treatment or test (Figure 1). The ISIP is approximately equal to treating pressure minus wellbore and near-wellbore friction effects.

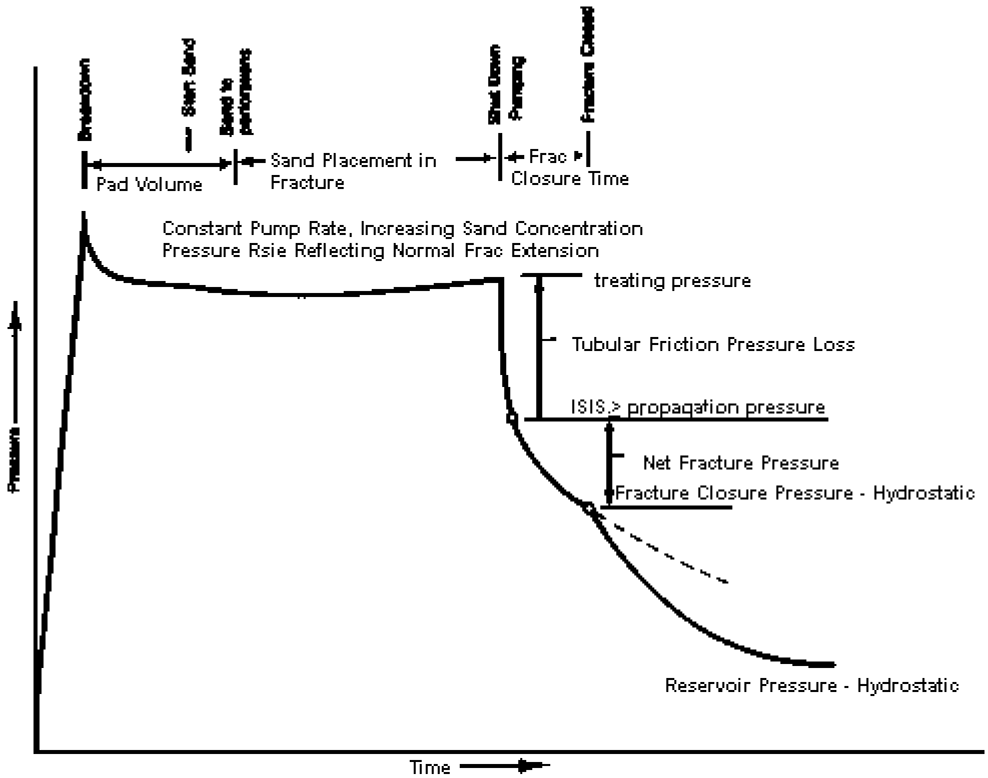


Figure 1

For a given point at the formation face, fracture propagation pressure is always lower than breakdown pressure. The difference between breakdown and propagation pressures is related to the tensile strength of the rock and near-wellbore stress patterns. In general, tensile strength for sedimentary rocks is on the order of hundreds of psi, but the difference between measured breakdown and propagation pressure can be greater than this. True propagation pressure in the sense defined above does not change through time; however, the propagation pressure which is measured at the bore hole almost certainly will change through a fracture treatment or test as the fracture extends. In wells with long openhole sections, new fractures can be formed whenever the injection pressure exceeds the breakdown pressure in a different section of the well bore.

The values recorded for treating pressure and ISIP are affected by the injection rate used for the fracture treatment or test. Because treating pressure and ISIP are measured at the surface, they are sometimes used as proxies for propagation pressure after depth correction; however, either may be significantly higher than propagation pressure. ISIP has been known to be less than 30 to more than several hundred psi higher than propagation pressure.

Fracture Closure: The closure of a fracture.

Closure pressure is the pressure at the formation face which is necessary to hold an existing fracture open, or in other words, the pressure below which fractures will not open (Figure 1). Closure pressure generally is measured instead of opening pressure because it is less affected by the test procedure and easier to observe. Closure pressure is equal to the minimum (usually horizontal) principal stress.

For a particular point in the wellbore, closure pressure is less than the fracture propagation pressure, sometimes only slightly less and sometimes on the order of a few hundred psi. The **fracture pressure gradient** is the fracture closure pressure divided by depth. This is the definition common to production and enhanced recovery operations, which are concerned about fracturing out of the production zone (e.g., Whitehead et al., 1986; Allen and Roberts, 1982). This definition is in contrast to that sometimes used during drilling operations, when the term "fracture gradient" may refer to the breakdown pressure gradient (i.e., breakdown pressure divided by depth).

Testing Methods: Direct Tests

Direct tests are those which pressurize a section within the injection interval to determine, as closely as possible, the conditions under which a fracture can be created, extended, or opened. It is important to note that direct testing under controlled conditions is not an environmental concern. The fracture which is initiated or propagated during testing generally extends only a short distance (on the order of a few feet) from the well bore and its vertical growth is limited by the test procedure. A short discussion of direct in-situ stress test methods is presented below. In all cases, a testing plan should be submitted and approval by Region 5 obtained before any new data acquisition commences.

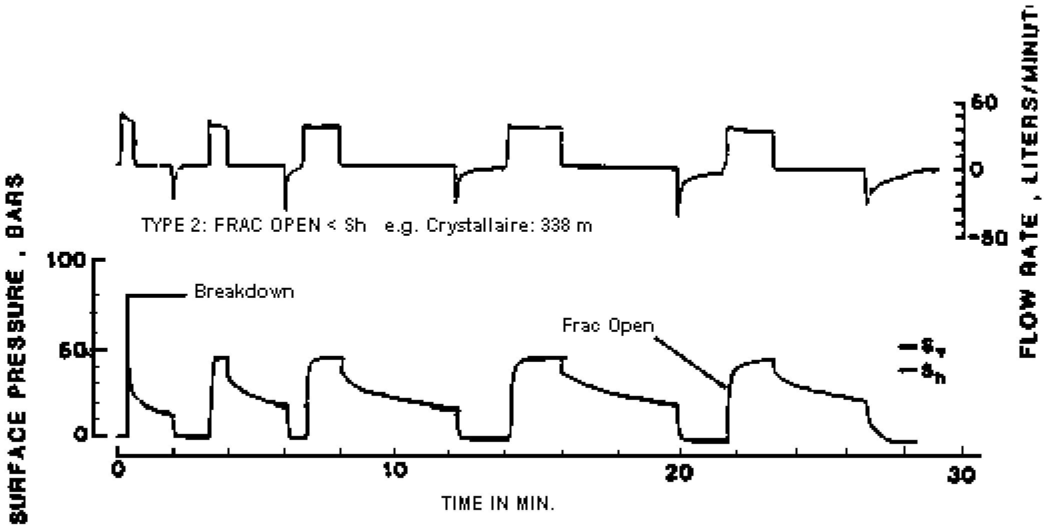
In all direct tests, downhole shut-off and downhole pressure gauges are recommended in order to acquire accurate data which are more easily interpretable. Depending on well construction, it will often be most appropriate to test large, representative sections of the injection interval, up to 50 or 100 feet thick. In such cases, however, higher fluid volumes and rates would be necessary than when testing a thinner zone. The fracture pressures resulting from such a test may be minimum or average fracture pressures, depending on what test is conducted. More accurate fracture pressures can be defined from thinner intervals (2 to 10 feet), but each result may in turn be less representative. When thin zones are tested, it generally will be necessary to test multiple zones.

Unless specifically tailored, conventional hydraulic fracture stimulations are only minimally useful for determining closure pressure. The ISIP recorded after treatment is most often hundreds of psi higher than closure pressure, and even when closure pressure itself is determined following the stimulation, back stress phenomena from pore pressure increase, due to fluid leak off, can lead to closure pressures which are unrealistically high.

If a test interval is fractured, either due to natural fractures or a previous acid frac or hydrofrac with proppant, breakdown is not likely to occur during testing. However, in some cases, closure pressure, ISIP, or a step rate test inflection point may be still be measured. In perforated completions, all measured pressures may be higher than in an otherwise similar openhole completion, because the fluid typically is not able to communicate its hydraulic pressure to the reservoir rock as easily. Therefore, when testing through perforations, this pressure drop usually must be calculated and accounted for in the test results.

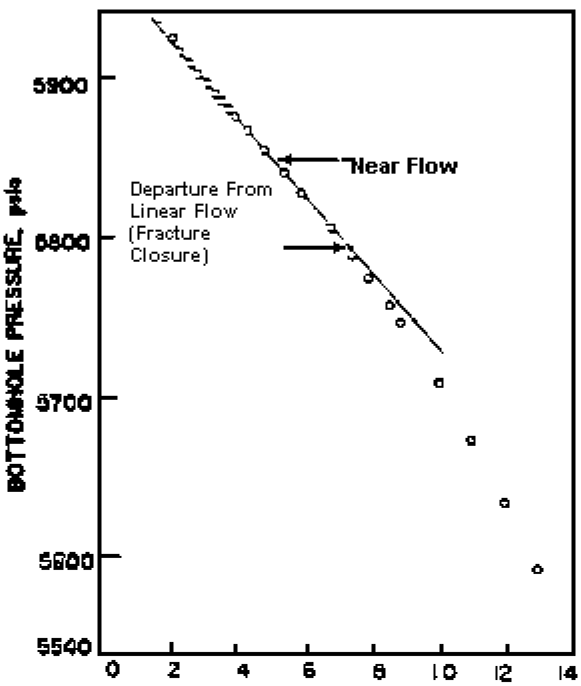
A. In-Situ Stress Tests

There are a variety of tests used to determine in-situ stresses, with little uniformity in their names (e.g., "minifracs", "microfracs", "stress tests", "pump-in, flow-back tests"). Many of these tests are performed by injecting a fluid into a moderately short section (a few feet to tens of feet) of the well bore at a single relatively low rate, until the rock fractures. Injection is typically continued for a few minutes, and then the pumps are shut down and the pressure allowed to bleed off. Multiple injection/fall-off cycles are usually performed as a quality control measure and the data are plotted with the pressure on the y-axis and time on the x-axis (Figure 3). Several methods are available for determining closure pressure from these types of tests. One method marks the deviation of formation face pressure from a straight line on a graph of pressure plotted against the square root of time (Figure 4). These tests are generally performed using a total of less than about 500 gallons of fluid, although in special applications or when testing a large interval, fluid volumes in excess of 150,000 gallons have been used. Interpretation by experts is necessary to determine propagation pressure and closure pressure in wells which have propped fractures.



From Hickman and Zoback (1983)

Figure 3.



Pressure falloff data from stress test at 8,316-18 ft, ARCO Phillips No. 1, Smith County, TX

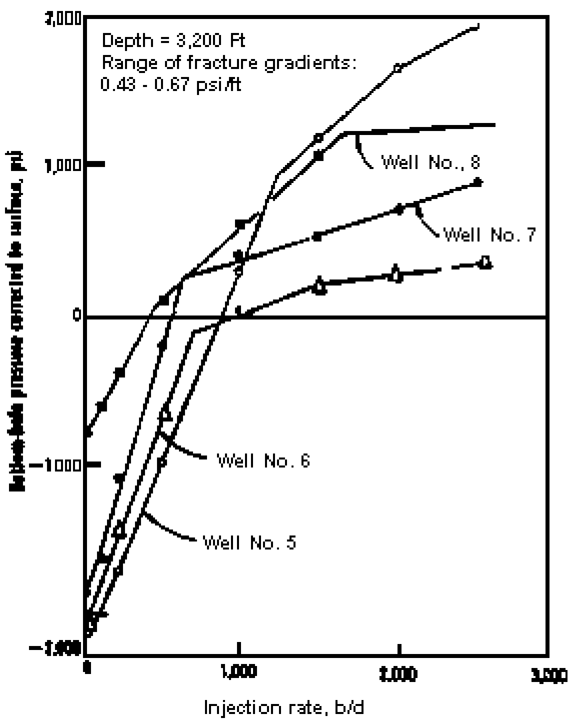
From Whitehead et al. (1986)

Figure 4.

B. Conventional Step Rate Tests

Conventional step rate tests provide an estimate of the pressure at which flow near the well bore ceases to be radial. This pressure is often interpreted as fracture propagation pressure (e.g., Singh et al., 1987); one can say at least that formation breakdown occurs at some point above this pressure and fracture closure occurs at some point at or below it. Step rate tests may also be run in combination with more specialized tests which are designed to determine fracture closure pressure. Step rate tests are most appropriately used in moderately to highly transmissive zones. Zones with low permeability are best tested by an alternate method, because of the specialized pumping equipment which is required to test these zones.

Step rate tests are performed by injecting fluid into a well in discrete steps and plotting injection pressure against injection rate. A change in the slope of a line connecting final injection pressure at each step indicates that flow to the wellbore is no longer radial because the rock matrix has fractured (Figure 2). In stratified injection intervals, different fracture pressures for different zones may result in multiple inflection points which may be difficult to interpret.



from Felsenthal (1974)
Figure 2.

Step rate tests can be performed on wells with or without tubing and packer, although in highly permeable or thick injection intervals a section may need to be isolated with straddle packers, necessitating removal of injection tubing. The pump capacity required by the test may vary from less than 5 gallons per minute (gpm) to more than 6 barrels per minute (bpm); fluid volume requirements are similarly variable. If large intervals are tested, pressure in the tubing due to friction may be a limiting factor as well. Traditionally, the injection rate is held constant for steps of equal length, and the stabilized pressure is recorded for each step. It is important that stabilization or pseudo-stabilization occur before moving to the next step. Variations on the conventional test sometimes include steps of unequal length and as short as a few minutes, but specialized interpretation is then necessary. In any case, it is important that several data points be established both above and below the inflection point on the graph so that straight lines can be drawn with some confidence.

When a well may have been injecting at pressures above the fracture pressure, it may be necessary to leave the well shut in for several days or longer before conducting a step rate test in order for the fracture to close prior to the test. If injection at these pressures has occurred for a long time, the fracture may not close and the step rate test may be misleading or not interpretable. Experts disagree about how frequently step rate tests conducted in wells with propped fractures give meaningful results.

Testing Methods: Indirect Stress Tests and Correlation Between Wells

Accurate stress data (and thus breakdown, fracture propagation, and fracture closure pressures) can only be determined in-situ. However, in some cases, specialized, processed logs and laboratory core tests can be used to estimate fracture pressures. The specialized logs are processed from a suite of open-hole logs, including a long-spaced sonic log. Information from the processed logs can be used in combination with laboratory core analyses of mechanical properties (Young's modulus, Poisson's ratio, compressive and tensile strengths) of the rock to estimate fracture pressures. These estimates may in some cases approach the accuracy of in-situ stress tests if the logs are accurately calibrated to in-situ test results on nearby wells where a long-spaced sonic log and cores are available. Indirect methods of determining fracture pressures may be adequate at sites where the desired MIP is much lower than expected fracture pressures. Where injection pressures are needed which approach expected fracture pressures, Region 5 may find that the accuracy of an in-situ stress test is indispensable.

In general, both long-spaced sonic logs and laboratory core analyses of mechanical properties are necessary to correlate stress test results between wells at different facilities, unless the facilities are extremely close together.

Note: This revised guidance supersedes the guidance on the same subject issued April 1993. The guidance is not intended to provide any person with any rights, substantive or procedural, not otherwise guaranteed by regulation or statute. It is not intended, and should not be construed to be, rulemaking of any sort.

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