CLASS I FRACTURE SLURRY INJECTION

A Summary of the Technology and Recommendation for Implementation

USEPA National Underground Injection Control
Technical Work Group
Report No. 1

by

Joe Kordzi

USEPA Region 6

February 26, 1998

I. BACKGROUND

For many years, the petroleum industry has successfully disposed of drill cuttings through a process known as fracture slurry injection (FSI). In its basic form, this process consists of grinding the drill cuttings to a relatively fine consistency, mixing the cuttings with water and/or other liquids to form a slurry, and disposing of the slurry by pumping it down a well at a high enough pressure that fractures are created within the target formation. The injected slurry is then emplaced in the fractures created by the force of injection. Recent work in this area has focused on extending this technology to the disposal of contaminated soils and other solid material associated with Superfund sites. If the injected waste is classified as a hazardous waste, an FSI well may be categorized as a Class I hazardous waste However, regarding Class I hazardous waste wells, 40 CFR §146.67(a)states:

> "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. The owner or operator shall assure that the injection pressure does not initiate fractures or propagate existing fractures in the confining zone, nor cause the movement of injection or formation fluids into a USDW."

Here, well stimulation is defined according to 40 CFR §146.3 as "... several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for wastewater to move more readily into the formation, and includes (1) surging, (2) jetting, (3) blasting, (4) acidizing, (5) hydraulic fracturing."

A similar restriction also applies to Class I non-hazardous waste injection wells under 40 CFR 146.13 (a) (1). Consequently, the FSI of waste would require that either the well be categorized as other than a Class I well, or that 40 CFR Part 146 be revised. This issue paper contemplates the latter case.

II. TECHNICAL CONSIDERATIONS

A. Summary of Basic Theory

An understanding of fracture mechanics can be facilitated by first defining a coordinate system, consisting of x, y, and z axes, which are mutually orthogonal, with the z-axis oriented in the vertical direction. At depths over approximately 3,000 feet, due to the weight of the overburden, the maximum principal stress is usually oriented along the z-axis, and the intermediate and least principal stresses are oriented along the x and y axes. Due to the fact that fractures propagate perpendicular to the least principal stress direction, a vertical fracture will propagate in the above described environment. Figures 1 and 2 depict this situation, with the fracture idealized as a single-planar fracture. As the depth to the target formation decreases, the stress due to the weight of the overburden also decreases, and the principal stress direction will deviate from the vertical direction. Eventually with continued decreasing depth, the principal stress direction will re-align itself in the horizontal x-y plane. Consequently, as the depth to the target formation decreases, induced fractures will change from being vertical to horizontal in orientation.

B. Concept of Disposal Domain

There is a great deal of information that leads to the conclusion that, except for short term single-event injection episodes, long term FSI does not result in the propagation of classical single-planar fractures. Rather, due to the repeated injection episodes, and the relatively high volumes often injected, a "disposal zone", which can be visualized as consisting of an array of branched fractures with possibly some rock disaggregation, evolves from the single-planar fracture. This situation, depicted in Figure 3, develops due to the tip of the fracture becoming clogged with injected solids to the point where it becomes easier for the fracture to continue as a branch off of the main fracture. Initially in the formation of this disposal zone, the branched fractures will tend to re-align themselves parallel to the main fracture. However, repeated injection episodes can alter the stress field within the disposal domain to the point at which the direction of the least principal stress re-equilibrates. Consequently, in the case of vertical fractures, this will cause the azimuth of newly propagating fractures to change. In theory, with continued injection, it is possible that the least principal stress field can even become vertical, which would cause fractures to propagate horizontally. This would be desirable, due to the elimination of vertical containment concerns.

C. Vertical Containment of the Injected Waste

Regarding vertical fractures, propagation will initially occur almost equally in the vertical and lateral directions. This process will continue until either (1) a stress barrier is encountered, a (2) "bleed-off" zone is encountered, (3) hydraulic horsepower limitations prevent continuance, or (4) the fracture "rolls over" due to re-equilibrium of the stress field. Because horizontal fractures propagate parallel to the ground surface, the issue of their vertical containment, except possibly in the instance of steeply dipping beds, is moot.

A typical stress barrier, mentioned in (1) above, consists of a relatively thick shale with a minimum horizontal stress significantly greater than that of the injection interval. Employing the coordinate system defined above, the fracture would, upon reaching a stress barrier, begin to expend most of its energy by propagating laterally. As wellbore pressure is increased to compensate for the increasing frictional pressure losses in the system, or due to the fracture tip becoming clogged, the fracture will extend itself farther and farther, on the order of a few feet, into the stress barrier.

The bleed-off zone mentioned in (2), above, is defined here as an interval with horizontal permeabilities significantly greater than those of the injection interval. Upon reaching such a higher permeability interval, the vertical and possibly lateral progress of the fracture may be suspended due to pressure bleed-off into the more permeable zone. With continued injection, filter cake buildup at the edge of the fracture that intersects the bleed-off zone may effectively shut off flow into that zone and allow additional lateral propagation of the fracture. This cycle may be continually repeated if the fracture continues to propagate laterally and the fracture continues to cut into fresh portions of the overlying bleed-off zone.

Regarding (3) above, in order to continue to extend a fracture, the pump engines must possess sufficient power to maintain a fracture tip pressure above the fracture propagation pressure. Consequently, the pump engines must have enough horsepower to overcome the energy losses of the system through frictional pressure drops in the tubulars and in the fracture, pressure losses due to leakoff into the surrounding formation matrix, and still supply the required energy to the system. This can impose a practical limitation on the vertical and lateral extension of hydraulic fractures.

Regarding (4) above, if neither barriers nor pump power requirements limit the vertical propagation of the fracture, at some point it will begin to roll over to the horizontal. This is because, due to the decreasing weight of the overburden experienced by the fracture as it propagates vertically, the maximum principal stress will at some point begin to deviate from acting downward along the z-axis. It will then become easier for the fracture to begin lifting the layers of rock than parting those layers.

Lastly, it should be noted that properly configured monitoring systems, as discussed in the next section, are capable of monitoring the height of the induced fracture. This provides the operator with an important control, allowing, in the case of real time monitoring, the shutdown of the system if the fracture begins to grow into an undesirable area.

D. Determination of the Height, Length, and Azimuth of Induced Fractures

The primary reason for the fracture prohibition clause in the Class I regulations was the uncertainty associated with the height of induced fractures, and the resulting concern of contaminating a USDW, or the land surface. Recently, technology has been developed that is capable of real time monitoring of the height, length, and azimuth of an induced fracture during injection operations. This technology was not available when the Class I regulations were promulgated. In addition, there is a great deal of information available (i.e., modeling studies, field data, etc.) that demonstrates that the height of the fracture can be confidently predicted, as well as controlled, based on the geological and mechanical properties of the receiving and overlying formations, the injection rate, and the hydraulic properties of the injectate.

There are currently two main methods through which the height, length and the azimuth (in the case of a vertical fracture), of an induced fracture may be monitored. These involve the use of tiltmeters and/or subsurface microseismic monitoring equipment.

Subsurface microseismic monitoring involves the downhole installation of geophones or accelerometers in offset wells, and/or the injection well itself, and the associated surface equipment used to process and store the data. This system depends on the ability of the equipment to triangulate the location of the fracture, through the analysis of the intercepted microseismic events. The accuracy of this system depends on the number of geophones or accelerometers installed, and the spatial location of this equipment relative to the loci of the particular microseismic events of interest. The advantage of subsurface microseismic monitoring is the ability of the system to monitor fracture geometry in real time. This affords a great deal of control over the operation. Although the operator cannot "steer" the fracture as it propagates, being able to monitor its height, length, and azimuth enables the cessation of operations in the event the fracture begins to propagate to an undesirable area. The main disadvantage of microseismic monitoring is the relatively high cost associated with the installation of the deep monitoring wells, which must be completed into the same interval as the injection well.

Tiltmeters are high resolution, angular displacement sensors that are usually arranged in one or more circular or elliptical arrays, usually within near-surface boreholes, surrounding the injection well. They measure the surface deformation field that results from the creation of fractures. The fracture geometry is then inferred from a geophysical analysis of this data, through a mathematical inversion - in effect, an automated procedure in which a large number of fracture geometries are successively compared to the data to obtain a best fit. Unlike subsurface microseismic monitoring, tiltmeter technology is not capable of monitoring fracture geometry in real time. However, tiltmeter data can be analyzed and interpreted very quickly. The main advantage of the use of surface tiltmeters is the relatively low cost of the system, compared to deep subsurface microseismic monitoring. Disadvantages include (1) the sensitivity of the equipment to noise, and weather conditions such as heavy rainfall, and (2) that surface tiltmeters are usually not accurate at inferring geometries of fractures that propagate at depths below approximately 5,000 feet, a limitation not applicable to subsurface microseismic monitoring. In addition, surface tiltmeter techniques are considered inferior to subsurface microseismic monitoring from both an accuracy and precision standpoint.

Recently, tiltmeters have been successfully deployed in deep monitoring wells, installed as vertical arrays in much the same configuration as the deep microseismic monitoring equipment discussed above. These "inclinometer" arrays overcome some of the limitations of surface deployed tiltmeters, such as sensitivity to noise, and because they are deployed in deep monitoring wells completed in the injection interval, they are not depth limited. In addition, inclinometer arrays are capable of "near real time" monitoring of the height, length, and azimuth of the propagating fracture. This can be accomplished in an automated mode by periodically analyzing the accumulated data, which similar to microseismic data is acquired in real time, in the same manner as described above for surface tiltmeters. In addition, inclinometer arrays can be deployed in the same monitoring wells as the microseismic arrays, providing an independent assessment of fracture geometry.

Following injection, the height of the fracture can be determined from various types of logs including temperature logging, and, if the injectate has been tagged by a radioactive isotope, through gamma ray logging. If the depth of the fracture is shallow enough to enable the use of surface tiltmeters, or if downhole inclinometers have been employed, the resultant, effectively permanent, change in the surface displacement can be measured through the use of precision leveling techniques, and the geometry of the fracture inferred. Other than these techniques, there is no known reliable non-intrusive procedure for measuring the length and azimuth of an induced fracture following the cessation of injection.

E. Presence of Wellbores and Subsurface Discontinuities

Knowledge of the location of wellbores, faults, natural fracture systems, and other possible subsurface discontinuities must be a critical part of the site evaluation for FSI. This is perhaps best illustrated by the March 17, 1997 incident on the Alaskan North Slope, in which approximately 18,000 barrels of water broached to the surface as a result of an FSI operation. The liquid phase of the injection is theorized to have intercepted production wellbores and utilized the pathway existing between the outside of the casing and the formation as a means to travel upward to the surface. The suspected intercepted wells are production wells completed in much deeper horizons. These wells are cemented across and immediately above the production horizons. However, these wells are typically not cemented at the elevation of the FSI operation. The operation has since been shut down and negotiations are on-going with the UIC Primacy State Agency, as of the date of this issue paper, for relocating the FSI operation to an area free of wellbores.

It is also possible that a fault plane, or some other geologic subsurface discontinuity could serve to transmit the fluid phase of the injectate across containment strata and to the surface. Consequently, it is recommended that (1) a thorough geologic study of the area be completed, (2) a thorough information search in the study area be performed so that all wellbores can be located, and (3) a large margin of error be included in any pre-injection prediction of the disposal domain dimensions.

III. DISCUSSION

A. Advantages of FSI over Conventional Waste Disposal Options

The deep injection of waste is the only disposal option that effectively removes waste from the biosphere. All other forms of disposal place the waste either into the air; landfills which are located above the water table; or rivers and streams that serve as recreation facilities, fish and wildlife habitats, sources of food, drinking water sources, or that recharge drinking water aquifers. Because injecting solids-laden fluids into the pore spaces of most rock would quickly plug it, without fracturing the rock to create the necessary void spaces, the injection of waste has been limited to fluids with a very low solids content. FSI technology has the capability of extending the benefits of deep well injection to any solid waste that can be crushed or ground to a fine enough consistency and mixed with water and/or another fluid to create a slurry. An obvious application of this technology is the remediation of RCRA or Superfund sites. It is projected that FSI would compare favorably to other disposal technologies, such as incineration, in the areas of economics, time, and public relations. In addition, with FSI, disposal is complete. There is no residual waste product that must be disposed, such as blow down salts from incineration air scrubbers. Lastly, surface reclamation can be total, in comparison with the common Superfund remediation strategy of collecting and capping the waste onsite, which may require perpetual monitoring and/or maintenance.

B. Potential Uncertainties and Limitations of FSI

Although fracturing formations for the purpose of stimulating oil production is a mature technology, portions of FSI, particularly the monitoring aspect, are relatively new technologies, having benefitted from advances in the last few years. As such, there are some risks to the Agency in advocating, through the revision of the Class I regulations, this technology as a waste disposal option. Should a failure in an FSI operation occur, it would be manifested as injected waste leaving the injection zone and being transported toward the surface. There are only two possible ways in which this could occur. The first case would be if the injected waste came into contact with a wellbore, or a subsurface discontinuity such as a fault. The second case being if an induced fracture propagated through the confining zone or to the surface. Prevention of the first case depends largely on the confidence in the geologic review of the site, and in the confidence that all wellbores or other possible discharge points have been located. Regarding the second case, fracture propagation theory concludes that a vertically propagating fracture will roll over when the fracture becomes shallow enough that the least principal stress direction becomes vertical. Having stated this, an account has emerged of an induced fracture reaching the surface. However, attempts to verify this incident have been unsuccessful as of the writing of this document. For reasons previously discussed, it is unlikely that a deep injection well could propagate a fracture to the surface. In addition, properly configured real time monitoring can prevent fracturing out of the injection zone by instantly notifying the operator of any vertical propagation out of the injection interval.

FSI is not suitable for all geologic environments and/or sites. Principally in the offshore petroleum industry, FSI has been successfully performed using relatively impermeable injection intervals (i.e., shales), in conjunction with relatively higher permeability barriers as bleed off zones (i.e., sands) serving to check the vertical extent of fracture propagation. However, considering land-based applications of FSI for the disposal of hazardous waste, there are a number of reasons why the injection interval should consist of a relatively low stress, moderate to high permeability sand, in conjunction with relatively lower permeability, higher stress shales, to check the vertical extent of fracture propagation. These reasons include:

1. Injection into relatively higher permeability zones, such as sands, favors the production of shorter, more compact fractures, which concentrate the waste near the wellbore.

2. Injection into relatively higher permeability zones, results in lower pressure buildup in the reservoir from the fluid portion (bleed-off) of the injectate.

3. The lower permeability of the stress barrier shales allows them to serve as effective confining zones, preventing the permeation of the liquid portion of the injectate into adjacent formations.

IV. RECOMMENDATIONS

FSI has the potential to positively impact the cleanup of many RCRA and Superfund sites as well as other facilities needing to dispose of non-hazardous industrial and/or domestic waste. However, because of the fracture prohibition statement in the Class I injection well regulations, 40 CFR 146.13 (a)(1) and 40 CFR §146.67(a), this technology is effectively prevented from being implemented. The UIC Technical Workgroup believes that the potential environmental benefits of FSI for specific injection sites may justify the revision of the Class I UIC regulations in order to implement FSI practices. Sufficient operational and monitoring controls can be placed on the use of this technology to ensure that the injected waste remains within the injection zone, and consequently does not contaminate a USDW. Due to the additional siting and monitoring requirements that are believed necessary, a simple revision to §146.67(a) is not considered adequate. Consequently, it is recommended that a separate subpart to 40 CFR Part 146 be created. Since Subpart H is the next available letter in the series, it should be assigned to FSI wells. Subpart H, although proposed to be exclusive to FSI wells, would carry over much of Subpart G, with minor modifications:

- §146.62 Minimum criteria for siting.
- §146.65 Construction requirements.
- §146.66 Logging, sampling, and testing prior to new well operation.
- §146.67 Operating requirements.
- §146.69 Reporting requirements.
- §146.70 Information to be evaluated by the Director.
- §146.71 Closure.
- §146.72 Post-closure care.

§146.73 Financial responsibility for post-closure care.

The remainder of Subpart G, would be carried over with heavy modifications:

§146.61 Applicability
§146.63 Area of review.
§146.64 Corrective action for wells in the area of review.
§146.68 Testing and monitoring requirements.

Of these, §146.63 and §146.64, which mainly discuss the size of the Area of Review (AOR) and the plugging of wells contained within the AOR, would not be appropriate for FSI. In the place of these sections, it is proposed that the AOR be defined based on a modeled prediction of the area of the disposal domain, with the addition of a safety factor. This prediction would be made based on a consideration of the geology of the injection interval, and the use of a fracture prediction model acceptable to the Agency. §146.68 would be modified to include the addition of microseismic and/or surface tiltmeter monitoring, with a provision to consider new technology, should it become available. In addition, it is proposed that the degree to which this monitoring be required depend on the geology of the injection interval and overlying sediments, the volume of waste injected, and the presence of wellbores or other subsurface discontinuities. Additional sections may need to be created in order that additional controls may be instituted to account for the uniqueness of FSI technology. Any regulatory changes should allow for further development of the technology rather than restricting it by requiring it to adhere to the current prediction and monitoring framework. This paper does not recommend any changes to the existing requirements under Part 148, which remain in effect due to the Land Disposal Restrictions under the 1984 Hazardous and Solid Waste Amendments to RCRA.

GENERAL REFERENCES

1. Charbeneau, R. J., Ogintz, J., and Aubert, W. G., "Fate of Waste Petroleum Sludge After Deep Well Injection." Paper SPE 28347, presented at the SPE 69th Annual Technical Conference and Exhibition, New Orleans, September 25-28, 1994.

2. Moschovidis, Z. A., Gardner, D. C., Sund, G. V., and Veatch Jr., R. W., "Disposal of Oily Cuttings by Downhole Periodic Fracturing Injections in Valhall-North Sea: A Case Study and Modeling Concepts." Paper SPE/IADC 25757 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, February 23-25.

3. Soliman, M. Y., Hunt, J. L., Azari, M., "Fracturing Horizontal Wells in Gas Reservoirs." Paper SPE 35260, presented at the 1996 Mid-Continent Gas Symposium, Amarillo, Texas, April 28-30.

4. Wright, C. A. *et al*, "Reorientation of Propped Refracture Treatments in the Lost Hills Field." Paper SPE 27896 presented at the Western Regional Meeting, Long Beach, CA, March 23-25, 1994.

5. Warpinski, N. R., "Hydraulic Fracture Diagnostics," JPT, (October 1996) 907-910.

6. Perkins, T. K., "Disposal of Waste Solids in Hydraulic Fractures." Paper presented at the SPE/International Assoc. of Computer Methods and Advance in Geomechanics, Morgantown, WV, May 23-28, 1994.

7. Wilson, S. M., Rylance, M., and Last, N. C., "Fracture Mechanics Issues Relating to Cuttings Re-injection at Shallow Depth." Paper SPE/IADC 25756 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, February 23-25.

8. Peterson, R. E. *et al,* "Fracture Diagnostics Research at the GRI/DOE Multi-Site Project: Overview of the Concepts and Results." Paper SPE 36449 presented at the 1996 SPE Annual Technical Conference and Exhibition held in Denver, CO, October 6-9.

9. Vinegar, H. J. *et al,* "Active and Passive Seismic Imaging of a Hydraulic Fracture in Diatomite." Paper SPE 22756 presented at the SPE 66th Annual Technical Conference and Exhibition, Dallas, October 6-9, 1991.

10. Branagan, P. T., Petersen, R.E., Warpinski, N. R., and Wright, T. B., "Characterization of a Remotely Intersected Set of Hydraulic Fractures: Results of Intersection Well 1-B, GRI/DOE Multi-Site Project." Paper SPE 36452 presented at the 1996 SPE Annual Technical Conference and Exhibition held in Denver, CO, October 6-9.

11. Keck, R. G., and Withers, R. J., "A Field Demonstration of Hydraulic Fracturing for Solids Waste Injection With-Real Time Passive Seismic Monitoring." Paper SPE 28495, presented at the SPE 69th Annual Technical Conference and Exhibition, New Orleans, September 25-28, 1994.

12. Brady, J. L., Withers, R. J., Fairbanks, T. D., and Dressen, D., "Microseismic Monitoring of Hydraulic Fractures in Prudhoe Bay." Paper SPE 28553 presented at the SPE 69th Annual Technical Conference and Exhibition, New Orleans, September 25-28, 1994.

13. Bruno, M. S., Bilak, R. A., Dusseault, M. B., and Rothenburg, L., "Economic Disposal of Solid Oil Field Wastes Through Slurry Fracture Injection." Paper SPE 29646 presented at the SPE Western Regional Meeting, Bakersfield, CA, March 8-10, 1995.

14. Minton, R. C., and Secoy, B., "Annular Reinjection of Drilling Wastes." Paper SPE 25042 presented at the 1992 SPE European Petroleum Conference, Cannes, November 16-18.

15. Louviere, R. J., and Reddoch, J. A., "Onsite Disposal of Rig-Generated Waste Via Slurrification and Annular Injection." Paper SPE/IADC 25755 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, February 23-25.

16. Malachosky, E., Shannon, B. E., and Jackson, J. E., "Offshore Disposal of Oil-Based Drilling Fluid Waste: An Environmentally Acceptable Solution." Paper SPE 23373 presented at the First International Conference on Health, Safety, and Environment, The Hague, November 10-14, 1991.

17. Abou-Sayed, A. S., Andrews, D. E., and Buhidma, I., M., "Evaluation of Oily Waste Injection Below the Permafrost in Prudhoe Bay Field." Paper SPE 18757 presented at the SPE California Regional Meeting, Bakersfield, CA, April 5-7, 1989.

18. Hubbert, M. K., and Willis, D. G., "Mechanics of Hydraulic Fracturing," *Trans.,* AIME (1957), vol. 210, pp 153-166.

FIGURE 1
IDEALIZED SINGLE PLANAR FRACTURE

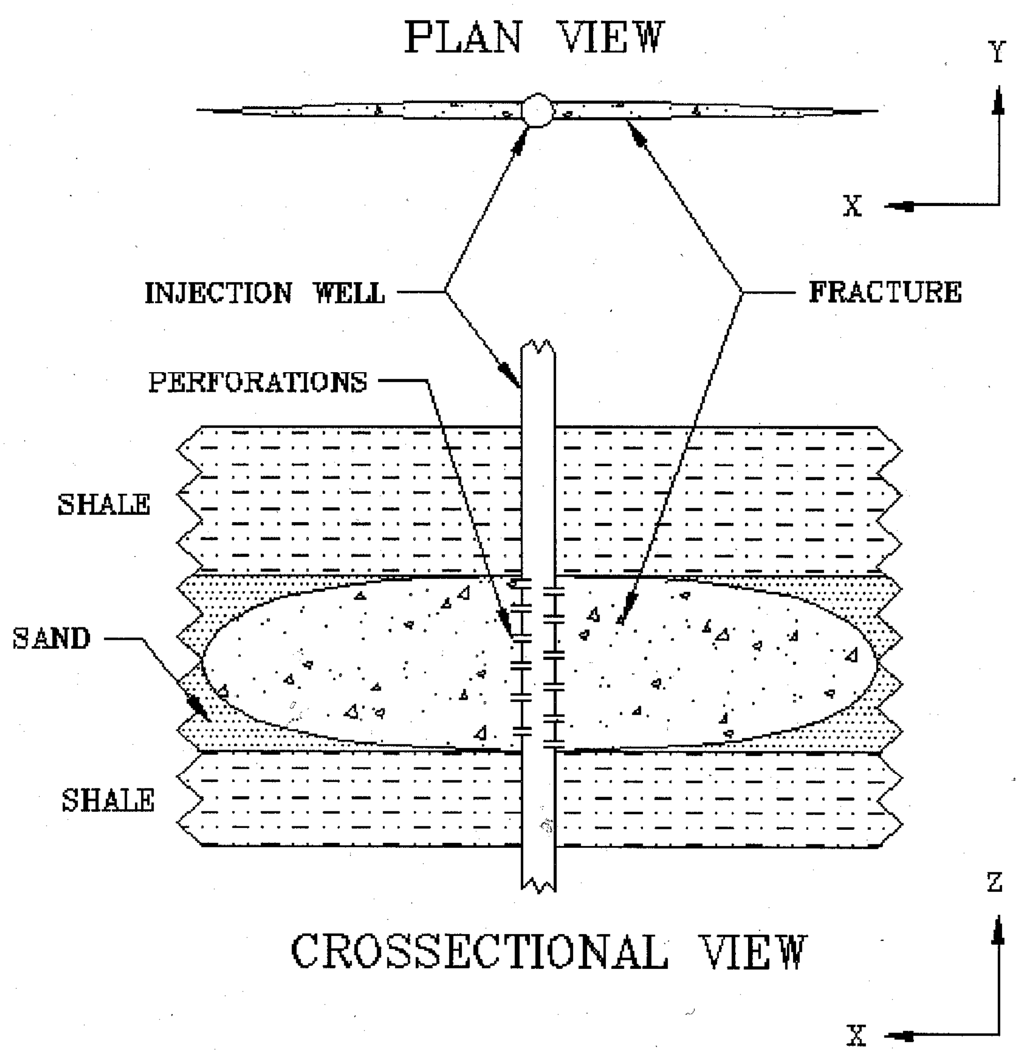

FIGURE 2
IDEALIZED SINGLE PLANAR FRACTURE

THREE DIMENSIONAL VIEW

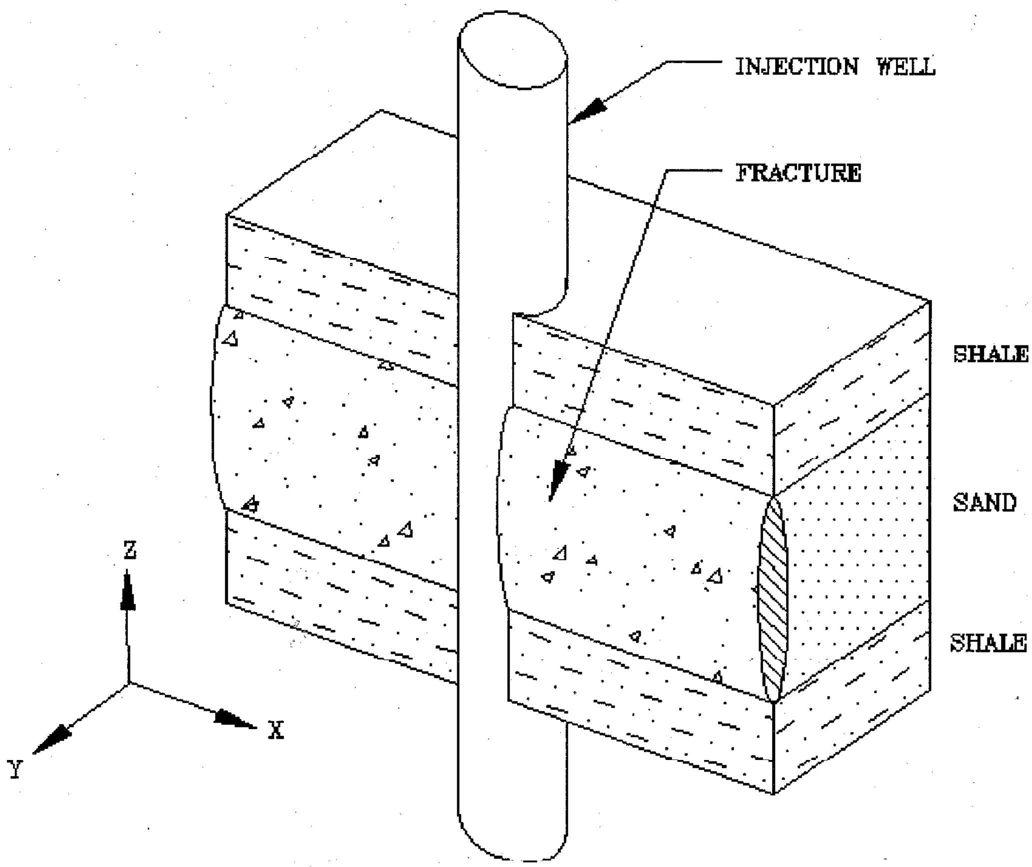

FIGURE 3
SINGLE PLANAR FRACTURE EVOLUTION
INTO DISPOSAL DOMAIN

PLAN VIEW