UNDERGROUND INJECTION OF BRINES

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ABSTRACT

Construction design and operating procedures for underground injection of brine waters are receiving more attention as the industry progresses toward full implementation of the provisions of the EPA Underground Injection Control regulations. Specific problems common to most injection well design and operation are discussed including casing and cementing programs, injectivity testing and reservoir performance calculations.

Special emphasis is placed upon limiting surface injection pressures to avoid such hazards as invasion of potable water reservoirs.

INTRODUCTION

An increased awareness of the potential environmental impact of underground brine injection operations has resulted in significant advances in both design considerations and operating procedures. Substantial revisions in planning, construction and operating requirements in the rules and regulations of both the Railroad Commission for Class II and the Department of Water Resources for Class I and III wells preceded the attainment of primacy in Texas for administering the EPA Underground Injection Control regulations. The Texas Railroad Commission adopted its regulations for Class II wells on April 1, 1982. The Commission received authority from the EPA to administer the program April 23, 1982.

Although for the most part the regulations now being followed are designed to provide protection for fresh water, they also serve, at least indirectly, to provide the operator greater control over the underground movement of injected brine, whether in a secondary recovery project or in a simple brine disposal scheme.

PLANNING

Two important elements in present-day planning for an underground injection operation are:

a. Review of existing water wells in the area and determination of the depth to the base of fresh water.

b. Review of all artificial penetrations into the proposed injection zone within a radius of 1/4 mile.

The principal use of information regarding fresh water in the area is in the determination of the minimum length of surface casing required to adequately isolate the fresh water reservoir from deeper formation fluids and/or injected waters. Also, in areas such as portions of central Texas and the Gulf Coast where fresh water may extend to 3000 or more feet below the land surface, the design of surface casing cementing procedures may require consideration of fracture pressures since the surface casing must be cemented throughout its length. The regulations also address cement quality such as compressive strength and use of extenders.

A thorough review of existing artificial penetrations is required in order to identify those wells where by reason of inadequate surface casing or inadequate plugging procedures, a potential path for flow of brine from the injection zone upward into fresh water zones might be possible. Although not specifically required by the regulations it is prudent to identify possible natural pathways to overlying fresh water zones.

CONSTRUCTION

As stated above, a basic requirement for an injection well is the installation of surface casing to a point below the deepest occurrance of fresh water and placement of cement throughout the length of the casing. While this might seem elemental to a West-Texas-New Mexico engineer dealing with fresh water generally above 300 or 400 feet, it can become a problem in central and south Texas areas. Consider, for example, the Gulf Coast area: in Fort Bend County, the base of fresh water is as deep as 2200 feet. Special design considerations are then necessary to insure complete placement of cement without formation fracturing.

Although cementing the production casing throughout its length is a requirement for Class I wells and has been almost universally specified for Class III wells, such is not required for Class II wells. However, it is required that cement behind production casing be brought to a point at least 600 above the casing shoe. Although not yet specified this indicates the desirability of continuous monitoring of bradenhead pressures in all injection wells.

The current regulations now require that injection be accomplished only through tubing below a packer set within 100 feet of the top of the injection zone. A typical Class II injection well is illustrated in Figure 1.

OPERATIONS

Monitoring of injection operations for Class II wells is limited by regulations to a minimum monthly recording of injection pressure and rate. These data must be reported to the Commission on an annual basis. However, in certain sensitive areas the Commission requires that the annulus be filled with fluid maintained at a positive pressure. In these instances the reporting requirements are also usually more stringent. Also, as stated above, monitoring of the bradenhead in wells where cement has not been circulated may well be desirable.

Where it is required to maintain positive pressure on a water column in the annulus between tubing and casing, it will be found desirable to provide a small pressure vessel at the surface. Such a partially filled vessel with nitrogen occupying the head space will serve to compensate for significant fluid volume changes in the annulus resulting from thermal expansion and contraction. Continuous monitoring of pressures becomes a simple matter.

The regulations are silent with respect to surface injection pressure limitations. For many years the usual procedure was to specify a maximum surface pressure equal to 0.5 psi per foot of depth to the top of the injection zone. This limitation, however, fails to take into consideration such important variables as pore pressure. It is well known that the fracture pressure of a formation varies directly as the pore pressure varies. It is not at all uncommon to commence water flooding operations at a time when the pore pressure is a small fraction of the original pressure. In such a case the fracture pressure would be much smaller than initially. Consider for example, a West Texas reservoir at 6000 feet which initiates water flooding at a time when the reservoir pressure had declined from 2500 psi to 500 psi. The surface fracture pressure, neglecting friction losses and skin effect, would have initially been in the range of 4000 psi; at initiation of injection for water flooding, the fracture pressure would have dropped to about 2850 psi. In recognition of individual hydrogeologic characteristics, the Texas Railroad Commission has in certain instances reduced maximum allowable surface injection pressures to as low as 0.35 psi per foot of depth.

Conducting injection operations at pressures exceeding fracture pressure have been related to earthquake generation at Rangely, Colorado (Ref. 3) and by inference at least, near the Cogdell Canyon Reef field near Snyder, Texas (Ref. 4). Induced seismicity is a matter of considerable concern. Exceeding the least principal stress particularly over a wide area, for any significant period of time, could trigger stress relief resulting in induced seisimicity.

Injectivity testing at the outset of an injection operation is a sure means of establishing acceptable injection rates and pressures. Such testing should not however, include establishment of fracture pressure directly since there is almost always a significant difference between initial breakdown pressure and fracture extension pressure and this differential serves as an effective safety factor. Injectivity testing will, however, identify and quantify pressures due to skin effect, or entrance losses, and provide the input data necessary for reservoir performance calculations.

CONCLUSIONS

Brine injection in the oil industry is indeed here to stay. More than three and a quarter billion barrels of water are annually injected in secondary recovery operations alone in Texas. Of this amount, about 64% is classified as salt water and about 17% as brackish water (dissolved solids exceeding 1000 mg/l). Injection wells can create problems including induced seismicity, uncontrolled water invasion of nearby oil producing zones and contamination of fresh water. On the other hand, with careful attention to both construction and operation parameters, the injection of brine can go forward in direct and close proximity to both surface and underground fresh water with no adverse effects, and without such undesirable impacts as earthquakes.

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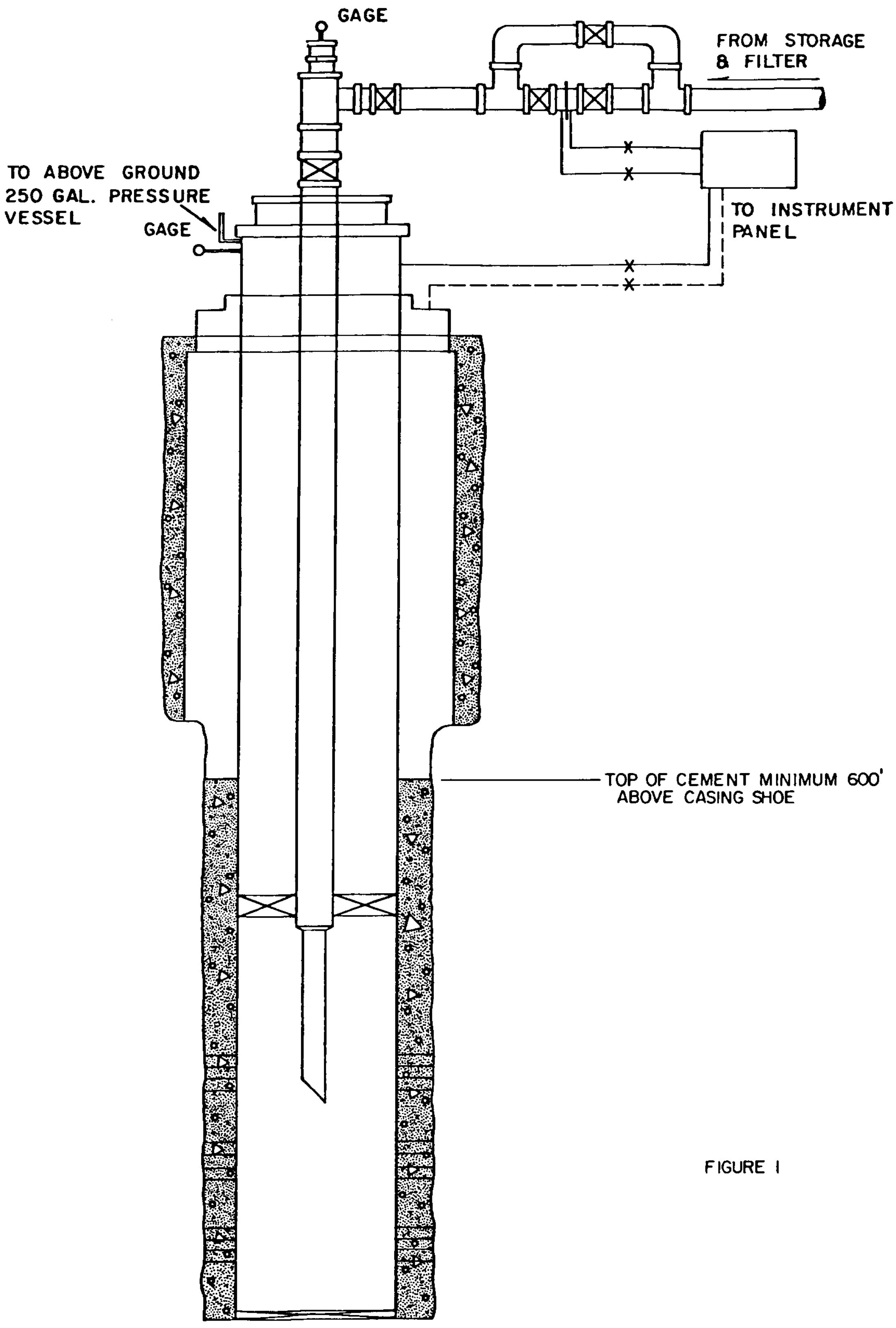
GAGE
FROM STORAGE
& FILTER
TO ABOVE GROUND
250 GAL. PRESSURE
VESSEL
GAGE
TO INSTRUMENT
PANEL
TOP OF CEMENT MINIMUM 600'
ABOVE CASING SHOE
FIGURE I

Figure 1