ORNL-4259

Contract No. W-7405-eng-26

HEALTH PHYSICS DIVISION

Radioactive Waste Disposal Section

ENGINEERING DEVELOPMENT OF HYDRAULIC FRACTURING AS A METHOD FOR PERMANENT DISPOSAL OF RADIOACTIVE WASTES

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AUGUST 1968

OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee
operated by
UNION CARBIDE CORPORATION
for the
U. S. ATOMIC ENERGY COMMISSION

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Acknowledgments

We gratefully acknowledge the help of the many people who have made this work possible. We are especially indebted to the Committee for Disposal of Radioactive Waste on Land of the Earth Sciences Division of the National Academy of Sciences–National Research Council for patience and kindness in advising us as to the problems and pitfalls in hydraulic fracturing work. We appreciate the aid from the American Petroleum Institute and from The Western Company during the initial phase of our mix development work. We are particularly grateful to The Halliburton Company, especially to W. D. Owsley, D. Hathorn, and J. M. Stogner, for their valuable assistance in designing the fracturing plant, in developing the mixes, and in performing the experimental injections. We thank the U. S. Geological Survey for their work during the second fracturing experiment in measuring uplift and tilt resulting from the injections and for their geothermal measurements in the Joy test well. The enthusiasm and support of many individuals here at the Laboratory (the Health Physics, the Chemical Technology, the Operations, the Plant and Equipment, and the Purchasing Divisions), for their help in all phases of the project, is recorded with gratitude. Finally, for the opportunity to pursue this work and to enjoy the many advantages of the Oak Ridge National Laboratory, it is a distinct pleasure to acknowledge the financial support of the Atomic Energy Commission.

1. Introduction and Summary

Early in 1958, D. A. Shock, Director of the Central Research Division of the Continental Oil Company (Conoco), Ponca City, Oklahoma, suggested to the AEC that hydraulic fracturing might be used in the disposal of radioactive wastes.[1] He was referred to the ORNL Health Physics Division's Radioactive Waste Disposal Section, and we were much interested in his proposal. The idea that hydraulic fracturing might be used as an aid in waste disposal had first been proposed at Continental Oil some years previously when J. J. Reynolds, then the director of the Division of Production Research, had suggested that the method be used to facilitate disposal of oil refinery wastes at Ponca City and for oil-field brine disposal in the Gulf Coast. The first recorded use of hydraulic fracturing for waste disposal, however, is in a paper by J. J. Grebe of the Dow Chemical Company.[2]

"In 1930 we were pumping brine down through the casing of a well for the purpose of disposing it in a porous sand stratum. The face of the well bore silted up. The flow decreased to a rather discouraging low value. Something had to be done. Ross Sanford, who was in charge of operation, did not hesitate to risk a pump for the sake of an experiment. We piled sand bags around it and raised the pressure from 150 psi on up. Suddenly at 720 psi the well took all we could pump. What is more, the pressure gradually decreased as more and more pumping capacity was applied.

"Back-flow tests indicated that there was an exact balance at 360 psi at which a flow would go in or out of the formation with very little pressure change. Then we knew we had actually lifted the earth and cleaved the interface between the strata sufficiently to get any amount of filter area required to force the brine into the porous formation."

The proposal by Reynolds and Shock in 1958 was based on a different use of the principle of hydraulic fracturing. Their suggestion was to fracture a well-bedded impermeable rock, like shale, and inject into the fracture a mixture of radioactive waste and some material, such as portland cement or sodium-sensitive drilling mud, which would harden in the fracture and immobilize the waste. The fracturing, therefore, was to be used to create the space in a formation with virtually no natural porosity, rather than to produce "any amount of filter area required,"

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[1] D. A. Shock, "Engineering and Research Proposal for Location and Test of Radioactive Waste Disposal Site at Oak Ridge National Laboratory," memorandum dated May 8, 1958.

[2] J. J. Grebe, "Tools and Aims of Research," *Chem. Eng. News* 21, 2004–12 (1943).

as in the example described by Grebe. The method proposed by Reynolds and Shock would provide a very real measure of double containment, one containment resulting from the solidification of the waste-cement mixture, which would rob the waste of the mobility characteristic of a fluid, and the second containment resulting from the very low permeability of the enclosing formation. Added to the mechanical containment provided by solidification of the mix and impermeability of the rock cover is the containment provided by the ion exchange capacity of the host rock, because rocks such as shale contain minerals with a high adsorptive capacity for virtually all the radionuclides in the waste. The mix also can be made to retain the radioactive materials either by adsorption or by incorporating them into the crystal structure of the newly formed solids. The most intriguing features of the Continental Oil proposal, however, were that, if the method could be made to work, waste could be disposed of in depth by a plant located entirely on the land surface and that the thin solidified waste sheets, with a high ratio of surface to volume, would dissipate the heat generated by radioactive decay relatively rapidly.

The AEC invited Mr. Shock to present his proposal to the Advisory Committee for Disposal of Waste on Land of the Earth Sciences Division of the National Academy of Sciences—National Research Council. One member of this committee was King Hubbert, with whom J. J. Reynolds and H. F. Coffer of Continental Oil had had at least one previous disagreement.[3] Although it is not apparent in the brief published comments of Reynolds and Coffer, two separate but related questions were involved in their criticism of Hubbert's paper. One concerned the relative pressures required to extend a horizontal and a vertical fracture, a subject discussed at some length in Chap. 4, Water Injection Tests. The second concerned the possibility of determining whether vertical fractures or horizontal fractures will be formed, by an appropriate choice of the method of well completion and of the liquid used for producing the fracture. The men of Continental Oil, as well as others, believed that the method used can at least influence the type of fracture formed. Some of their statements, however, gave the impression that they believed they could absolutely control the type of fracture (vertical or horizontal) produced, without regard to the nature of the rock involved or the preexisting stress in the rock. When Shock presented his proposal to the Committee, they asked how it would be possible to prevent the formation of vertical fractures, which might well carry the waste up to or near the land surface, where it could contaminate shallow ground water or surface water. Mr. Shock expressed confidence that the formation of vertical fractures could be prevented and stated that his company had a patent on a method for controlling fracture orientation. This did not convince the Committee, and they advised against proceeding with his proposal.

Although at the time we did not understand all the issues involved, it appeared that a potentially promising method of waste disposal was being ruled out in no small part because of disagreement among the several protagonists, each of whom was basing his position on somewhat different assumptions. It was therefore proposed to the AEC and to the NAS-NRC Committee

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[3]M. K. Hubbert and D. G. Willis, "Mechanics of Hydraulic Fracturing," *Trans. AIME* 210, 153 (1957).

that we attempt a preliminary test at Oak Ridge to determine empirically what type of fracture would form in the Conasauga shale. This proposal met with the Commission's and the Committee's approval; however, we were enjoined not to draw general conclusions from such an ad hoc approach or to make plans to put substantial quantities of activity into the ground until we had firmly established where it would go and what would become of it.

FIRST FRACTURING EXPERIMENT

The first fracturing experiment (Chap. 3) was undertaken in October 1959 to determine whether, at the shallow depth of 300 ft, vertical or horizontal fractures would form in the local shale and also to "test the testing method." The method consisted in drilling a well to the required depth, cementing in a casing, slotting the casing with a high-pressure water-sand jet, and then pumping down the well 27,000 gal of a mixture of water, cement, and diatomaceous earth tagged with 35 curies of ^{137}Cs and 8.7 curies of ^{144}Ce. All the equipment and operations used were similar to those employed in the petroleum industry except for the use of a radioactive tracer.

Following the injection a 3-in. core drill was used to drill holes at various distances and directions from the injection well in order to locate the grout sheet. In some cores the grout could be located by inspection, since the cement mixture was lighter colored than the host rock. A portable gamma-sensitive survey instrument was able to identify the grout sheet in a few cores where it was not readily apparent to the eye. The most successful method of locating the grout sheets, however, was to log the core hole with a gamma-sensitive probe. In no case did the response of the probe leave any doubt as to whether or not the hole being surveyed had penetrated the grout sheet. The gamma-ray logging could not tell us, however, how thick the grout sheet was; so it was desirable to recover a rock core containing the grout.

In this first experiment, we found that "horizontal" fractures had been formed, or to be more accurate, the fractures were found to follow closely along the bedding planes of the shale. In geological terminology, such fractures are said to be "conformable." In much of the following discussion, however, they are referred to as "horizontal," for this term is more generally understood, although in fact most of the fractures dip 20° or so, following the bedding.

At about this same time, the Continental Oil Company was making some field tests of hydraulic fracturing in the Sacatosa field (Maverick County, Texas), not for the purposes of waste disposal but to convince the State regulatory authorities that by the use of fracturing they could drain all recoverable oil from the field with an even wider spacing of wells than the authority had recommended.[4] For this they needed to identify the fracture in the test wells that they drilled around the fractured well in various directions and at distances of up to 250 ft. The test wells were cored through the critical interval at a depth of about 1330 ft, and the fracture was identified in the cores, was located by drill stem tests in the wells, and was detected in the

[4]J. J. Reynolds, "Hydraulic Fracture – Field Tests to Determine Areal Extent and Orientation," *J. Petrol. Technol.* 13, 371–76 (April 1961).

drill cuttings by identifying the sand that had been injected into the fracture along with the fracturing fluids. Although their methods were adequate for their problem, the results clearly showed the superiority of a radioactive tracer for locating the fracture in areas where the use of such tracers is possible. Apparently the tests made by Continental in Texas and our tests at Oak Ridge are the only ones in which the extent and orientation of a deep hydraulic fracture have been clearly determined.

SECOND FRACTURING EXPERIMENT

Following the successful completion of the first fracturing experiment, plans were made for a second experiment at depths of about 700 and 1000 ft (Chap. 3). To some extent, the selection of these depths was arbitrary. However, we felt that this was deep enough to provide sufficient rock cover for an actual disposal operation; also, this depth could be reached by locally available heavy-duty water-well drilling equipment, and a site at which suitable shale could be reached at this depth interval was available adjacent to a 4-in. water line and an electric power line.

Preparations for this experiment were somewhat more elaborate than for the first one. First, a 3-in. test well was drilled 30 ft from the proposed location of the injection well and was cored all the way from the surface to a depth of 1050 ft. The core showed that the red shale member of the Conasauga occupied the depth interval between 700 and 1000 ft. A small-diameter pipe, with the bottom 150 ft drilled at 1-ft intervals with small holes, was lowered to the bottom of the hole and cemented in from a depth of 892 ft up to the surface. In this way the test well could be used to measure the pressure in the first fracture, after the fracture had broken into the bottom uncemented section of the hole.

Next, the main injection well was drilled, also to 1050 ft, and a 4-in.-ID casing was cemented into the hole.

Bench marks had been installed at the site of the first fracturing experiment and their relative elevations determined before and after the injection. The results showed that there had been a slight uplift of the surface, but it could not be measured precisely with the instruments then available. Consequently, a network of 38 bench marks was installed at the site of the second experiment, and their relative elevations were determined with high-precision equipment prior to the first injection and after each of the two injections.

The first injection of the second experiment was made September 3, 1960, at a depth of 934 ft; it comprised 91,567 gal of grout containing 25 curies of ^{137}Cs. The second injection, on September 10, at a depth of 695 ft, comprised 132,700 gal of grout, also containing 25 curies of ^{137}Cs. In the fall of 1960 and the spring of 1961, 24 core holes were drilled to determine the positions of the two grout sheets by the techniques used in the first fracturing experiment. Both were found to be conformable to the bedding, although both sheets had worked upward a little stratigraphically as they moved out from the injection well to the north and east.

FURTHER PRELIMINARY INVESTIGATIONS

The results of these preliminary experiments convinced us that we should begin an investigation of the other problems that had to be resolved before we could hope to dispose of real waste by hydraulic fracturing.

One of the first problems was the choice of a site for the disposal plant. The site chosen was near the junction of White Oak Creek and Melton Branch, roughly midway between the sites of the first and second fracturing experiments. This spot was selected for a number of reasons, one being that the red shale (Pumpkin Valley) member of the Conasauga shale was estimated to occupy the depth interval between 700 and 1000 ft, as it had at the site of the second fracturing experiment. It was felt that the red shale at that depth was well suited to a disposal operation. In June of 1961, the Joy Drilling Company was engaged to drill a core hole about 3000 ft deep near the proposed plant site. The finished hole was 3263 ft deep and served two purposes. First, we wanted to find out if the lower part of the Rome sandstone had sufficient porosity so that filtered liquid waste could be injected directly into it, without any cement, using fracturing to provide access for the liquid, much as Grebe did in the account quoted above. No rock with any appreciable porosity was found. The second reason for drilling the deep hole was to explore the Chickamauga limestone, which underlies the Rome (Chap. 2). Surface exposures of this formation in Bethel Valley show two members of thin-bedded limestone that look as though they would fracture easily along the bedding planes. These two members were penetrated by the test hole, the first from 1642 to 1847 ft and the second from 2648 to 2852 ft, and the cores from the material in depth looked at least as promising as the surface exposures.

In the spring of 1961 development work was started on waste-cement mixes that might be suitable for use in disposal by hydraulic fracturing. The Division of Production of the American Petroleum Institute arranged a meeting in Houston in April 1961, at which the problem was discussed with representatives of the petroleum industry. Their experience with the cementing of oil-well casings, with "squeeze" cementing to shut off water or quicksand, and with drilling muds was of considerable interest, but little of their information could be applied directly to our problem. Late in 1961 a contract was arranged with Westco Research, a subsidiary of the Western Company (Fort Worth, Texas). This and all subsequent work on mix development are described in Chap. 5.

In December 1961 the results of the second fracturing experiment, the mix development work by Westco, and the preliminary results from the Joy test well were discussed with the NAS-NRC Committee. The Committee agreed that the formation of conformable fractures had been demonstrated at Oak Ridge and gave guarded approval to push toward the possible eventual use of the method for actual waste disposal.

In October 1961 the Advisory Committee of the Health Physics Division suggested that the injection of significant quantities of actual waste into the shales within the Chickamauga formation at depths between 1642 and 2852 ft might be more suitable than injection into the shales above the Rome formation. However, a study of the expense of drilling wells to a depth of 3000 ft showed that mapping and monitoring of disposal operations at this depth would be too costly, and, although the idea was and still is attractive, we decided against moving the next experiments to this deeper level and into an untested formation.

In July 1963 the NAS-NRC Committee reported to W. G. Belter, Chief of the Environmental and Sanitary Engineering Branch of the AEC, that "there is considerable evidence that near-surface layered sedimentary rocks will fracture from induced hydraulic pressure preferentially parallel to bedding planes, whereas in more deeply buried horizontal or moderately dipping strata, the induced fractures are usually vertical. We recommend, therefore, that the zone of disposal for a pilot-plant operation at Oak Ridge National Laboratory be limited to the red-shale member of the Conasauga shale overlying the Rome quartzite and that no further work on deep hydrofracturing be done until after the results of the pilot-plant operations are known."

The work on waste-cement mixes by Westco continued through 1962. By mid-1962 several promising mixes had been developed, and arrangements were made with the Halliburton Company (Duncan, Oklahoma) to test the mixing and pumping characteristics of one of these mixes. At the same time, the Halliburton Company was engaged to help with further development of suitable waste-cement mixes and with design of the surface plant and of the three original wells: the injection well, the observation well for gamma-ray logging, and the shallow "rock cover monitoring" well.

DESIGN AND CONSTRUCTION OF FRACTURING PLANT

In one sense, the design and construction of the wells and the surface plant were relatively simple because virtually all the equipment already existed and was being used in the petroleum industry. The problems in fact, however, were complex but fell into two general categories. The first concerned how much money to spend in order to get the best and safest equipment possible. It was quickly discovered that some compromise was necessary. For example, a so-called "extreme line" casing was obtained for the injection well. This casing has longer threads than ordinary casing, which makes it stronger, but it is also somewhat more expensive. However, we did not purchase a "blowout preventer," a hydraulically operated guillotine valve sometimes installed on the casing of an oil well just below ground level to seal the well if high-pressure gas is encountered in drilling. Such a device might be of great value if the casing broke just below the wellhead while injecting waste. The cost of the preventer and accessory equipment was more than could be justified.

The second general question was what to buy and what to rent. The plant in 1962 was still basically an experiment, and the work was funded on that basis. Such items as the four bulk storage bins could have been rented, but the possible saving was small compared with purchase; so in most cases a calculated risk was taken that the results of the tests would be favorable, and the equipment was purchased. One exception was the standby high-pressure pump which would be used to clear the injection well in the event of failure of the main pump when the well was filled with a waste-cement mixture. This pump would need to handle only cement-water slurries, and we decided to rent a truck-mounted pump, which Halliburton would bring with them when they came to operate the plant.

The waste injections were to be made into the red shale between depths of 1000 and 700 ft. Three types of wells and the bench marks for measurement of uplift were constructed, as shown in Fig. 1.1. The injection well was for the injection of waste, and the observation well, located 150 ft north of the injection well, was for the determination of the depth of the grout sheets. The rock cover well (200 ft north of the injection well) was a prototype for more wells of this type that would be constructed later. The injection well and the observation well were drilled to a depth of 1050 ft, cased, and cemented in for their entire length. All waste injections were to be made through slots cut in the casing and surrounding cement of the injection well. As the injections proceeded and the grout sheets spread out from the injection well, they could sometimes be expected to intersect the cemented casing of the observation well, and the gamma-sensitive probe lowered into the observation well would then detect the presence of the grout sheets, thereby establishing the depth of the grout sheets at that point.

The overlying gray calcareous shale, and in particular the shale between depths of 700 and 400 ft, would provide an essentially impermeable cover to the injection operations. However, this cover rock would be deformed progressively by the injections, and at some point, which is

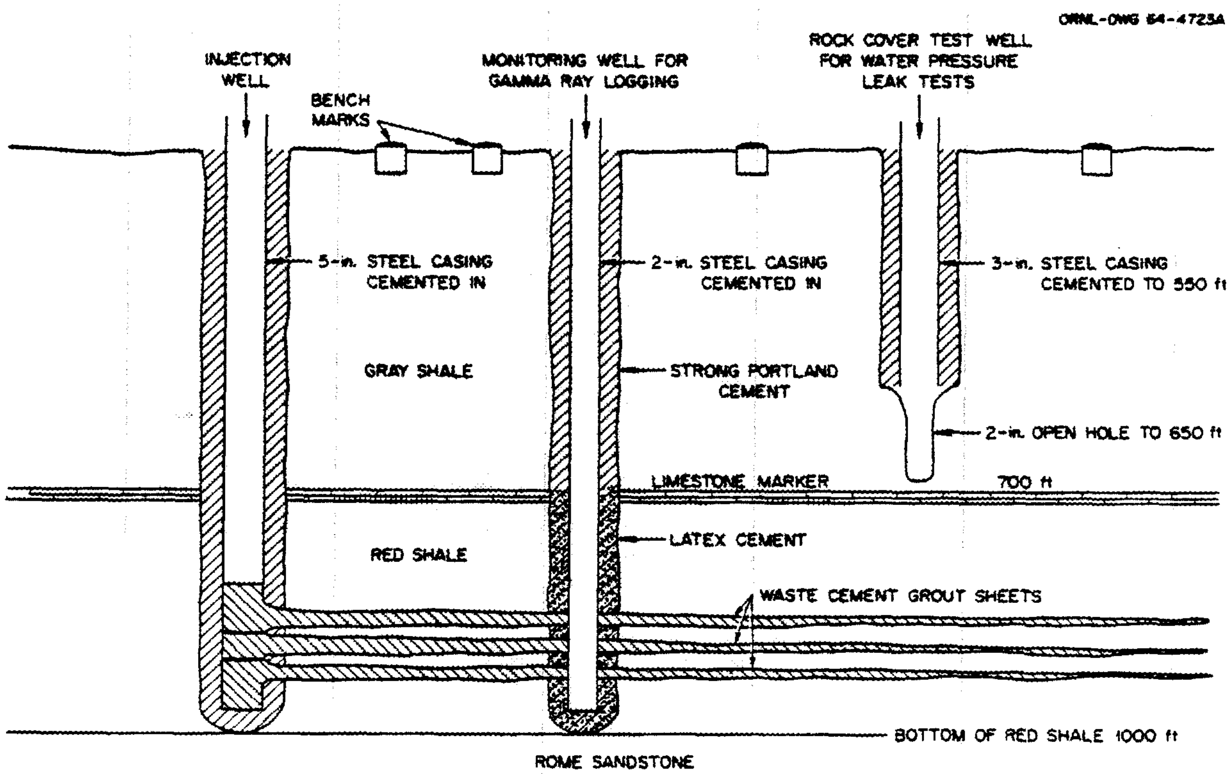

Fig. 1.1. Sketch of Three Types of Wells Constructed at the Fracturing Plant Site.

difficult to predict, the cover rock could fail and its value as an impermeable cover be materially reduced. The so-called "rock cover monitoring" well was designed to give warning when this happened. This well was cased down to about 500 ft, below which there is 100 ft of open hole. After each injection an attempt would be made to pump water into the well at some standard pressure, say 75 psi. The rate at which the well takes water would be noted, and if the rate increases, this would indicate that the shale adjacent to the open hole section of the well had become more permeable.

Actual work at the plant site began in the spring of 1963. After the wells had been installed and while the rest of the plant was under construction, the four water-injection tests were made (Chap. 4); this was from June to November 1963.

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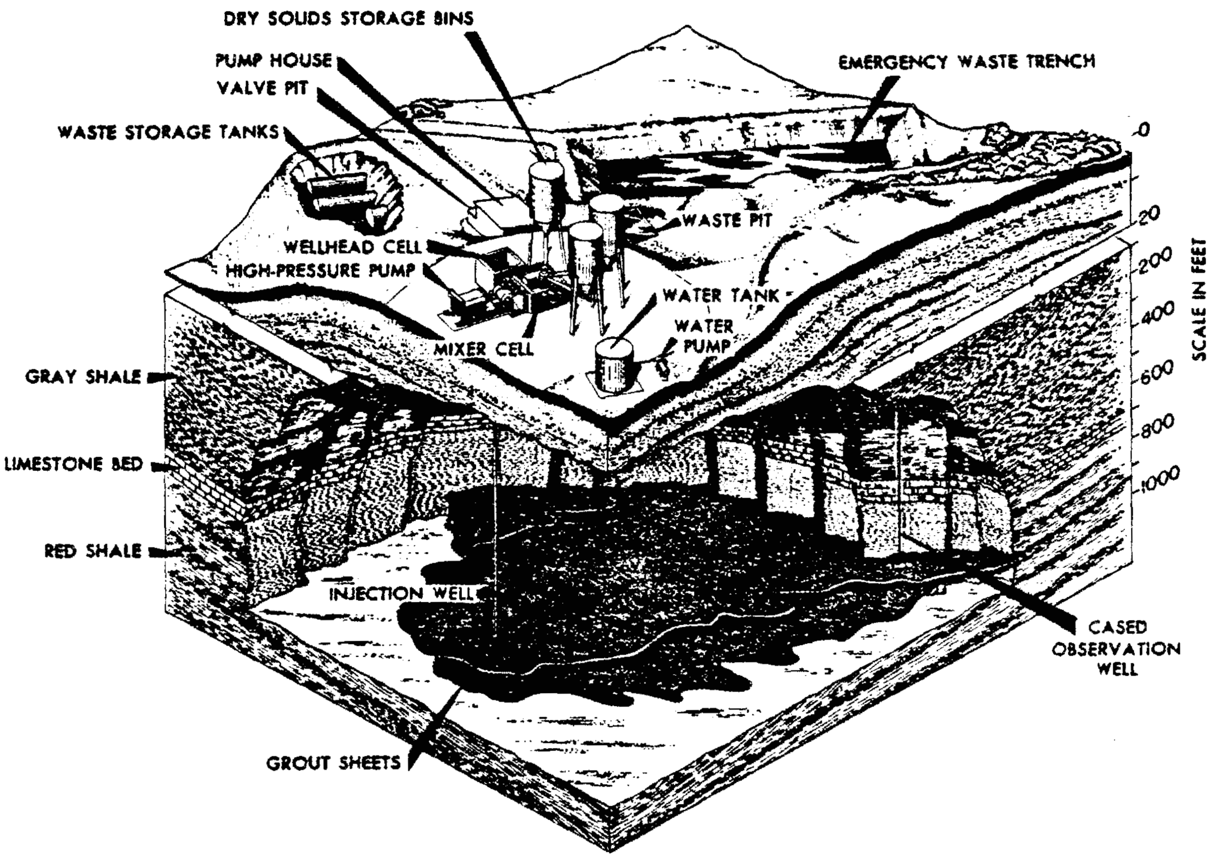

Fig. 1.2. Isometric Drawing of ORNL's Hydraulic Fracturing Plant. Cutaway shows relative locations of the injection well and the observation well and two hypothetical grout sheets in place.

The plant equipment consisted of a waste transfer pump and spare, four bins to store the cement and other solid constituents of the mix, a jet mixer, a surge tank, a high-pressure injection pump, and assorted valving and special equipment. The mixer, surge tank, injection pump, and wellhead valving were installed in cells to reduce the radiation exposure of the operators and to limit the area that would become contaminated in the event of a leak. The cells were made of a 12-in. thickness of concrete block and were roofed with sheet metal. All necessary control operations were to be carried out from outside the cells during an injection. An artist's overall view of the plant and the wells is shown in Fig. 1.2. Shown also are two hypothetical grout sheets in the disposal formation.

EXPERIMENTAL INJECTIONS 1 THROUGH 5

The plant was finished early in 1964, and the first five experimental injections were made in the period from February 13 to May 28. These injections, described in Chap. 7, served several purposes. First, they provided an opportunity to try out the plant and train the operators while using "cold" mixes or mixes containing only small quantities of activity. Second, they made it possible to test several types of mix under field conditions. These field tests provided information on the problems of actually mixing the solids and the waste in the desired proportions, and later, after samples of the grout had been recovered by deep coring, they made it possible to compare grout that had hardened under pressure with grout that had hardened without pressure in the laboratory. Third, the five injections made it possible to begin field tests of the prototypes of the deep gamma-ray observation wells and of the rock cover monitoring wells. Fourth, they made it possible to begin a study of the fracture pattern created at the plant site.

The first five injections went very well. There were minor problems with the plant, but in general these were easily corrected.

A point of fundamental interest brought out during the five injections was the difficulty of proportioning the mix in the plant so that it would meet the specifications established in the laboratory. When operating, the plant pumps liquid waste at a rate of up to 250 gpm and, with a mix of 6 lb/gal, must feed the preblended solids to the jet mixer at a rate of 1500 lb/min. To measure and accurately control these two feed lines is a formidable problem. In the oil fields the proportioning of cement to water is controlled by measuring the density of the mix, but in our case, with a higher-density fluid and a lower proportion of solids, the density of the mix is a relatively insensitive indication of the proportion of solids to liquid. Another problem revealed by the results of the five injections was the difficulty of designing test procedures for evaluating waste-cement mixes in the laboratory. In general, we started by relying on the criteria used to judge the cement grouts used in the petroleum industry and the fluids used in the hydraulic fracturing of oil wells. Rather early in this work, however, it was found that fluid loss additives (Chap. 4, Water Injection Tests), widely used in oil well fracturing, were not needed in this operation.

Despite these problems, we learned how to operate the plant, considerably improved the grout mixes, and successfully pumped substantial quantities of activity deep underground.

The permeability of the open hole section of the rock cover test well, which was about 2 gph at 75 psi, did not change appreciably during the course of the five injections.

After injection 5, four core wells were drilled to determine the location of the grout sheets, to obtain samples of the grout, and more clearly to define the geologic structure into which the grout sheets were being injected. Two of the four holes encountered none of the grout sheets; one of these flowed back nonradioactive (but salty) water, which came from injection 1 or 2 or from one of the fractures formed during the water injection tests. The other two wells, however, pierced all or most of the five grout sheets. The data from this coring and from gamma-ray logging were insufficient to define the attitude or shape of the first five grout sheets, but they appeared to be conformable. After the four core holes were completed, they were converted into gamma-ray observation wells to be logged after each subsequent injection. Three more rock cover test wells were constructed northeast, northwest, and south of the injection well when the core drilling was done following injection 5.

EXPERIMENTAL INJECTIONS 6 AND 7

Injections 6 and 7, described in Chap. 8, were made in the period from May 19 to August 16, 1965. While the first five injections had been made almost without incident, injection 6 was marked by three unexpected events which at the time caused considerable concern. All three, as it developed, resulted from changes in procedure: a change from the Densometer to a mass flowmeter to aid in controlling the solids-to-liquid ratio in the mix and the substitution of fly ash for part of the portland cement in the mix.

Injection 6A (injection 6 was made in two parts) started off smoothly enough, but the jet mixer plugged suddenly after only a few minutes, and contaminated dry solids and grout spilled out on the floor of the mixer cell. The injection was halted, and the cell, the jet mixer, and much of the associated equipment in the mixer cell were washed down with water. The contaminated wash water was pumped down the well, a possibility which had not previously been considered, but which, when the need arose, greatly facilitated the cleanup. When the mixer hopper was finally clean, it was discovered that it had been plugged by a plastic cone, a part of the mass flowmeter, which had broken free and fallen into it. Later, by the substitution of a stronger cone, this potential problem was eliminated.

Some 19,000 gal of wash water was pumped into the slot at 880 ft, and consequently the injection well was plugged back with cement and a new slot cut at 872 ft. The injection was resumed three days later.

Again the operation went smoothly at first, but then trouble developed from plugging of the coarse screens in the air slides leading to the mixer hopper from the solids storage bins, and it was necessary to remove these screens. The lumps in the blended solids had resulted because some of the fly ash was wet. The fly ash, a waste material at the steam plants, is collected by precipitators in the smoke stacks, and little care is taken in storing it.

With the removal of the screens, hard lumps reached the injection pump, and one of the valves was unable to close properly and was soon eroded. This led to uneven operation of the pump and to much more vibration in the high-pressure piping than was present under normal conditions. After nearly 70,000 gal of waste mixture had been injected, the operation was halted while the pump was repaired. Shortly after the injection was restarted, however, one of the connections at the wellhead cracked as a result of the earlier vibrations and sprayed the wellhead cell with waste-cement mixture. This was also cleaned up with surprisingly little difficulty, but since the well was out of commission for the first part of this remedial work, not all of the contaminated wash water could be pumped down the well.

The cracked fitting on the wellhead was later replaced with a stronger piece, and a new cone was installed in the flowmeter. On August 16, 1965, injection 7 was made, virtually without incident, into the slot at 872 ft; however, the mass flowmeter did not yet operate as well as had been hoped.

In retrospect, the incidents which interrupted injection 6 were very valuable to the project. Contamination of the mixer cell and later of the wellhead cell represented almost a "maximum credible accident," at least with the level of activity in the waste then being injected. Despite this we were able to decontaminate the plant and the equipment and proceed with the injection with comparatively little delay and with only negligible exposure to the workmen. The causes of the accidents were factors, such as excessive vibration, which had been recognized but perhaps not fully appreciated, and in part were completely unexpected, such as the failure of the cone in the mass flowmeter. These accidents prompted us to study the plant and the methods of operating it with the hope of forestalling trouble and cautioned us of the need to field test any new piece of equipment or new operating procedure.

Following injections 6 and 7 the six monitoring wells then available were logged, and the results, while not entirely satisfactory, strongly suggested that these fractures, also, had been conformable. Such gamma-ray logging provides immediate, direct evidence of the location of essentially horizontal grout sheets and together with occasional core drilling forms one of the principal methods of monitoring the disposal operation. Vertical core holes and vertical cased gamma-ray logging wells, however, cannot provide proof that vertical fractures have not formed, as these could come up between and parallel to the vertical wells. As we now understand the mechanics of fracturing in bedded rocks, a vertical fracture would not come up very far without forming new horizontal fractures at a shallower level, and these would be picked up by the logging (Chap. 10).

The permeability of the open hole sections of the four rock cover test wells did not change appreciably. Meanwhile, an additional use for the wells developed during the course of injections 6 and 7 which promises to be of more value than the purpose for which they were originally installed. These wells normally contain water almost up to the land surface. When these injections were made into fractures deep in the disposal formation, the water level in some of the rock cover wells was seen to rise and even overflow, while in others the water level fell a few feet. By filling all these wells with water prior to the injections and equipping each with a pressure gage, changes in pressure were noted which appear to indicate the direction taken by the fracture in moving out from the injection well. Correlations with the results of the gamma-ray logging have not been completed, but there appears to be a marked rise in pressure in the rock cover wells under which the fracture has passed and little rise, or even a drop in pressure, in the wells located in other directions.

OPERATIONAL INJECTIONS ILW-1 AND ILW-2

Following injection 7, on August 16, 1965, the disposal plant was put on standby; the dominantly experimental part of our program was completed, and the waste evaporator was still under construction. It was understood, however, that when concentrated waste was available, the plant would be reactivated and used for actual disposal operations. Responsibility for the plant was consequently placed in the hands of the Operations Division, and they saw to it that the plant was kept in condition. In the spring of 1966 the waste evaporator went into operation, and by fall enough waste concentrate had been collected to make an injection. Review of the condition of the plant showed that many improvements and modifications were required, including an increase in the waste storage capacity from about 40,000 gal to 80,000 gal, an increase in the capacity of the electric power line, a weigh tank to aid in proportioning the cement, fly ash, and other solids, and a permanent water line. Of the major items, only the weigh tank and the water line were installed by the time of the next injection, but many of the minor items had been taken care of. On December 12 and 13, ILW-1, the first actual disposal operation with real waste, was made into the fracture at 872 ft, the same fracture that had been used for injections 6B and 7. A total of 72,000 gal of waste, containing about 20,000 curies of ^{137}Cs and minor amounts of other nuclides, was disposed of at an out-of-pocket cost of about 30¢/gal. There is little to say about the operation except that everything went smoothly; in particular the Densometer and the mass flowmeter worked well, holding the proportion of liquid to solids within satisfactory limits.

During the next few months the two new waste storage tanks were installed, bringing the usable waste storage capacity to a little over 80,000 gal.

The next disposal, ILW-2, was made on April 20 and 24, 1967. This time 148,000 gal of waste concentrate, containing nearly 60,000 curies of cesium and over 1000 curies of strontium, was pumped into a new fracture at a depth of 862 ft. The out-of-pocket cost was less than 20¢/gal. There were a few minor delays in connection with this operation, but the only significant problem resulted from a decision to omit the sugar from the mix. The sugar is used primarily to extend the pumping time, but there was no need for an extension when the pumping time for this mix was determined for 65°F, the approximate temperature of the host rock. But the sugar also reduces the viscosity of the mix, which we found too viscous to pump with the sugar left out. This fault was corrected during the injection operation by reducing the proportion of solids from 6.25 to 6.00 lb/gal, but only at the risk of increasing the phase separation.

CONCLUSIONS AND RECOMMENDATIONS

In retrospect, after nearly eight years of work, there is surprisingly little that we wish we had done differently, so that this report may speak for itself. This statement, we trust, does not represent self-satisfaction, but rather is based on our acknowledgment that we took advantage both of our abundant good luck and of the help and advice of many knowledgeable men. We were lucky in that the local geology proved favorable for waste disposal by hydraulic fracturing. No other waste-producing research or operational center now active in this country, or as far as we know in the whole world, has geology of a type likely to be suited to this unique method of disposal, except possibly the Nuclear Fuel Service plant near Buffalo, New York. We were also fortunate that our Laboratory produces an intermediate-level waste in sufficient volume and with sufficient activity so that the operation of the experimental plant for actual disposal operations was both feasible and attractive. Experiments in radioactive waste disposal are no doubt an essential part in the development of new methods, but only actual operations involving many thousands of curies can truly test a new method, and a proper evaluation of the procedure can be made only after many years of operation. This is one of the reasons for our concern over tank storage; no matter how good a job is done by our generation someone else will have to be concerned with the wastes left in tanks.

But in a broader sense the geology of the Oak Ridge area is in no way unique, for perhaps a third of the United States is underlain by flat-lying well-bedded sedimentary rock containing thick formations of shale. To be sure, the experience of the petroleum industry has been interpreted as showing that vertical fractures are commonly formed by hydraulic fracturing, and by implication vertical fractures would also be formed in attempts to use hydraulic fracturing for waste disposal. Two questions must be resolved, however, before we accept this unfavorable conclusion. First, what do the records of oil-well fracturing show about the pressures involved? No comprehensive study appears to have been made. The point is of sufficient interest that we tentatively suggest such a study should be made, not so much for its value for waste disposal, but rather for the information it would supply about a basic geophysical problem. Our reservations principally concern the accuracy of the available data. Wellhead pressures, even when accurately recorded, are an unreliable indication of the actual pressures within the fracture.

The second question concerns the mechanics of the fracturing of rock by the injection of fluids. Certainly no comparison should be drawn between the fracturing of cased and uncased sections of a well. In an uncased well the fluid pressure tends to enlarge the volume and hence the circumference of the well bore, and the force applied acts directly to produce vertical fractures. Such fractures have, indeed, been photographed, and these photographs have been advanced in support of the contention that vertical fractures are commonly formed. But in a cased well, the fluid pressure in the well bore is contained by the casing and is only applied to the surrounding rock through a narrow horizontal slot cut in the casing. This method of application of the fluid pressure tends to form a horizontal fracture, a point frequently emphasized by our friends at the Continental Oil Company. But such fractures, whatever their orientation, cannot be photographed because the well is cased, so that photographic evidence is strongly biased in favor of vertical fractures. In general, measurements and observations made inside the fractured well will identify a vertical fracture but will not clearly reveal a horizontal fracture because of its geometry.

Virtually all oil-well fracturing is in rocks with at least some measurable permeability, and in this case the pressure of the fracturing fluid is at least partially transmitted, through the fluid already present in the rock, more or less equally in all directions. This is equivalent to saying that the system is dominantly hydrostatic or, if you will, hydrodynamic. With an equal pressure change in all directions the rock will fracture first in the direction normal to the least original pressure in the rock, granted that the rock is not importantly stronger in one direction than in another. But when fluid pressure is applied to a disk-shaped slot in virtually impermeable shale, the pressure change in the rock is not equal in all directions. The horizontal area of the slot is much greater than the vertical area of its narrow perimeter, so that a much greater force in pounds is directed vertically than laterally. Just what the forces are around the tip of the fracture is a difficult problem to analyze, but they appear to favor the formation of, or perhaps we should say the continuation of, a horizontal fracture.

To the extent that the shale is permeable and to the extent that fluid does leak off into the shale, the vertical force will be increased as compared with the lateral forces because the liquid will move out between the beds, not normal to them. We need a much more sophisticated, and unfortunately complex, analysis of the forces guiding the tip of a fracture in markedly anisotropic nearly impermeable rock before we can translate the experience of the petroleum industry, in apparently producing largely vertical fractures, into a judgment of the amount of "luck" we had in producing horizontal fractures in the shale at Oak Ridge. It may well be that the horizontal fractures are the rule, not the exception, in horizontal beds of shale. If this is true, then the areas geologically suited for disposal by hydraulic fracturing would include a third or so of the United States; however, any area considered for this type of disposal would have to be individually tested. Our recommendation would be a much more thorough study of the mechanics of hydraulic fracturing in well-bedded rocks, a problem which may be too complex for mathematical analysis.

The theoretical analysis of the mechanics of hydraulic fracturing is also important to virtually every aspect of the continued safe use of the method after a disposal system has been put into operation. Such questions as how deep to drill the disposal well, how much waste-cement grout to put into any single fracture, and how far apart to space the fractures are still unresolved. If, as appears probable, these questions cannot be handled by a mathematical analysis based on existing theory, then experiments with models should be attempted, despite the difficulty of reproducing the physical properties of the system at a reduced scale.

A related problem is the probable mode or modes of failure, for this will determine how the disposal area should be monitored. The location and value of the so-called rock cover monitoring wells is a case in point; if they do not provide a reliable method of detecting incipient failure they are likely to give a false sense of security.

We have felt, perhaps incorrectly, that the useful role of hydraulic fracturing would probably be in the disposal of intermediate-level wastes and particularly of intermediate-level waste high in dissolved solids and possibly containing flocculent precipitates. Suspended solids can be handled by the mixer and the injection pump, and satisfactory waste-cement mixes appear to be possible even with highly salted solutions. Also, the probable volumes of intermediate-level waste, and more particularly of the wastes from chemical decladding, appeared to be of a convenient size for this method of disposal. By "convenient size" we mean of the order of 1000 or 2000 gpd, so that an 80,000-gal injection could be made every two or three months. The very-low-level wastes and the wastes consisting of potentially contaminated water appeared at first to be too voluminous, that is, of the possible order of hundreds of thousands of gallons a day, to be handled by the method. But hydraulic fracturing of a formation, such as a sandstone, with low but measurable permeability and appreciable porosity, say 10 to 15%, could quite possibly handle large volumes of low-level waste. Fracturing in this case would be used to provide a pathway into the formation, and disposal would be into the natural porosity of the rock and not into the fracture. No cement would be added to wastes disposed of in this way. An obvious candidate for this type of disposal would be the tritium-rich condensate from the evaporation of high-level waste.

At the other end of the waste spectrum are the high-level wastes themselves. We are much more confident than we were a few years ago that a surface plant can be designed to handle waste with thousands of curies to the gallon, if adequate shielding and provision for decontamination are designed and built into the plant in the first place. A more formidable problem is the safe upper limit, in terms of curies per gallon of ^{137}Cs or ^{90}Sr, that can be disposed of by fracturing into shale, considering the subsequent heat rise. If the boiling point of water is taken as the limiting temperature, the upper limit would probably permit disposal of some high-level waste, but this limit is probably too conservative. The danger would come, presumably, in the escape of steam and hot water containing dissolved fission products and the transport of the radioactive materials up to near the earth's surface. This possible mechanism is very like that responsible for the formation of hydrothermal ore and mineral deposits. Such systems have been studied in some detail, and similar methods could probably be used to predict the circumstances under which hazards might result from the generation of heat within a solidified grout sheet of radioactive waste and cement. We believe these calculations should be undertaken by someone versed in the physical chemistry of the formation of ore and mineral deposits.

In more general terms, our conclusion is that the possibility of using hydraulic fracturing for waste disposal in other areas should be explored and that consideration should be given to using the method to dispose of wastes other than the medium-level wastes for which it is now employed at Oak Ridge.

2. Geologic Setting

OAK RIDGE AREA

Oak Ridge is located in the "valley and ridge" physiographic province, a belt of faulted and folded rock which lies between the "Blue Ridge" subdivision of the Appalachians to the southeast and the "Appalachian Plateau" to the northwest. It extends from Pennsylvania to Alabama, where its possible continuation in an arc curving to the west is obscured by a cover of younger deposits. In the Oak Ridge area the province is about 50 miles wide and is marked by a series of great overthrust faults, in each of which a layer of rock very roughly two miles thick has moved as much as several tens of miles to the northwest, overriding the similar sheet of rock in front of it and in turn overridden by the sheet behind it.

The dimensions of the sheets, the distances moved, and the strength of the rock involved apparently preclude the early hypothesis that they were pushed from the rear. The more recent suggestion,[1] that while the Appalachian Mountains were uplifted, the sheets slid down very gentle slopes under the force of gravity along fault planes in which friction had been very greatly reduced by fluid pressure, has aroused much interest. The mechanism of the thrust faulting is of importance to disposal by hydraulic fracturing at Oak Ridge because the faulting might have left residual stresses in the rock and would certainly influence the type and distribution of minor folds and faults in the several formations that make up the thrust sheets.

Since the latter part of the Appalachian Revolution, when the thrust sheets were formed, at least 10,000 ft of rock has been removed by erosion. The fault sheets, as presently exposed, are each bounded below by one of the major overthrust fault planes and above by a fault plane or an erosion surface, so that both the top and bottom of the original stratigraphic column are missing.

The two fault sheets of immediate interest to the work at Oak Ridge are each composed of four formations (Fig. 2.1). The oldest is the Rome sandstone, of lower Cambrian age, of which only the upper 350 ft is present in the Oak Ridge National Laboratory area; the lower part, perhaps as much as 1000 or 2000 ft thick, was left behind when the thrust sheets were formed. That part of the upper Rome present in the test and disposal-plant areas is largely composed of beds of hard brittle quartzite 1 in. to 1 ft thick. The Rome is overlain by the Conasauga shale, about

[1] M. K. Hubbert and W. W. Rubey, "Role of Fluid Pressure in Mechanics of Overthrust Faulting," *Geol. Soc. Am. Bull.* 70, 115 (1959).

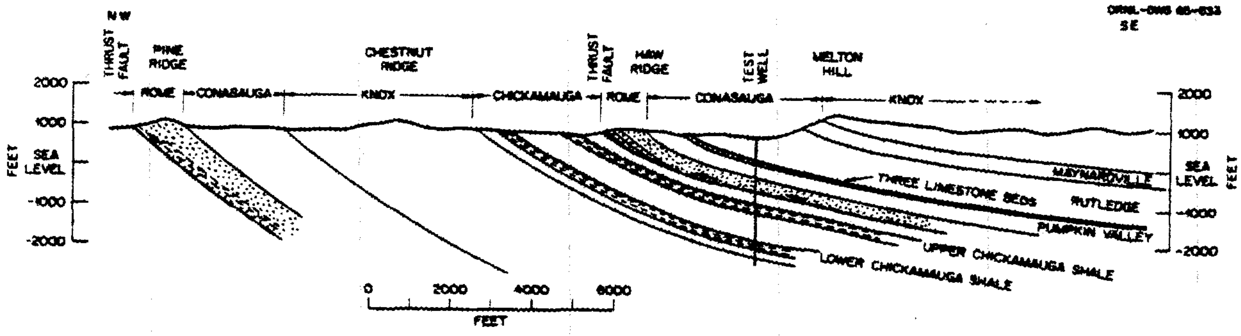

Fig. 2.1. Subsurface Geology ORNL Fracturing Plant Site.

2000 ft thick. The bottom 300 ft of the Conasauga, the Pumpkin Valley member, is dense argillaceous shale that is very thin bedded and dominantly red. This is the unit into which all the test injections have been made. The Pumpkin Valley is overlain by what is probably the Rutledge member of the Conasauga; however, this correlation, and in general much of the local stratigraphic correlation and nomenclature, while the best presently available, should not be regarded as firmly established. The so-called Rutledge, about 1000 ft thick, is composed of gray calcareous shale interbedded with generally thin beds or lenses of limestone. The contact between the Pumpkin Valley and the Rutledge is marked by three beds of limestone. The Rutledge is overlain by the Maynardville limestone member of the Conasauga, generally thin-bedded and locally oolitic and fossiliferous.

Above the Conasauga is the Knox dolomite, about 3000 ft thick and composed of thick beds of more or less cherty dolomite. The lower part of the Knox is believed to be of Cambrian age and the upper part of Ordovician age. Variations in texture and composition, particularly in the associated chert, have made it possible for workers in other areas to subdivide the Knox into four or five formations; but in Oak Ridge it is still classed as a single stratigraphic unit. Springs, caves, and sinkholes are common in the Knox, and groundwater apparently moves through it rather easily along a complex network of joints, many of which have been enlarged by solution.

The Knox is disconformably overlain by the Chickamauga limestone, of Ordovician age, about 1700 to 2000 ft thick in the fault blocks in the Laboratory area but somewhat thicker in some of the other fault blocks which are cut by the overthrust faults at a higher stratigraphic horizon. Where intersected by test drilling, the formation contains two members of thin-bedded red calcareous shale, each about 200 ft thick and each apparently well suited for disposal by hydraulic fracturing (Fig. 2.1). The rest of the formation is well bedded, hard, medium- to fine-grained limestone.

The formations all dip to the southeast, the Rome at 45° near the outcrops of the overthrust faults, but to the southeast of the faults the dips flatten out to 10 to 20°. The beds within the fault sheets are, in general, relatively little deformed. The competent Rome sandstone is somewhat faulted and fractured, particularly near the fault plane, but, considering the distances moved by the fault sheets, the breakage is surprisingly small. The overlying Pumpkin Valley is in general undeformed except for the regional dips already mentioned, but locally it is marked by drag folds, all overturned toward the northwest and varying in amplitude from about an inch up to several feet. The lower part, at least, of the Rutledge locally shows similar drag folding, but the axes of these folds are less regular, so that the deformation might better be called crumpling than folding. The Maynardville, the Knox, and the Chickamauga show no such minor structures in the vicinity of ORNL, although in other parts of the Valley and Ridge Province, they, or rather the individual thrust sheets containing them, are more or less complexly faulted and folded.

MELTON VALLEY SITE

The site in Melton Valley (at the junction of Melton and White Oak Creeks) selected for the projected large-scale experimental waste injections was chosen with the general geology already in mind but with the precise spot chosen in order to meet certain operational and administrative requirements. These requirements were: (1) proximity to such operating waste disposal facilities as the burial ground and the seepage pits and trenches, (2) proximity to a waste-transfer pipeline, (3) remote from any existing or proposed Laboratory facilities, and (4) within the drainage area of White Oak Lake, the discharge from which was already being monitored. The Knox and the upper Conasauga, a total of over 3000 ft of the stratigraphic column, had already been ruled out for disposal by fracturing because they are largely thick bedded or generally very hard and brittle. The site is at a point stratigraphically just below these rocks and is immediately underlain, in consequence, by that part of the section of greatest interest.

Joy Test Well

In the summer of 1961 a test well was drilled by the Joy Drilling Company at the site to a depth of 3263 ft to explore these rocks. The hole was cored all the way, and gamma-ray and electric logs were made nearly to the bottom. A study of the data confirmed, incidentally, that this site is very nearly at the same stratigraphic position as the site of the second fracturing experiment, which is 3000 ft away to the northeast. The log of the well (Fig. 2.2) may be summarized as follows:

Middle Conasauga

0 to 440 ft. Interbedded gray limestone and calcareous shale, beds 0.1 to 1.0 in. thick, except locally 1 to 2 ft thick. Bedding irregular in detail and locally shows drag folds ranging from a few inches to several feet in amplitude. Does not appear well suited for disposal by fracturing due to irregularities in bedding.

440 to 544 ft. Calcareous shale with less interbedded limestone than above. Bedding thin and regular; cores, in general, break evenly along bedding. Relatively little deformed – this may

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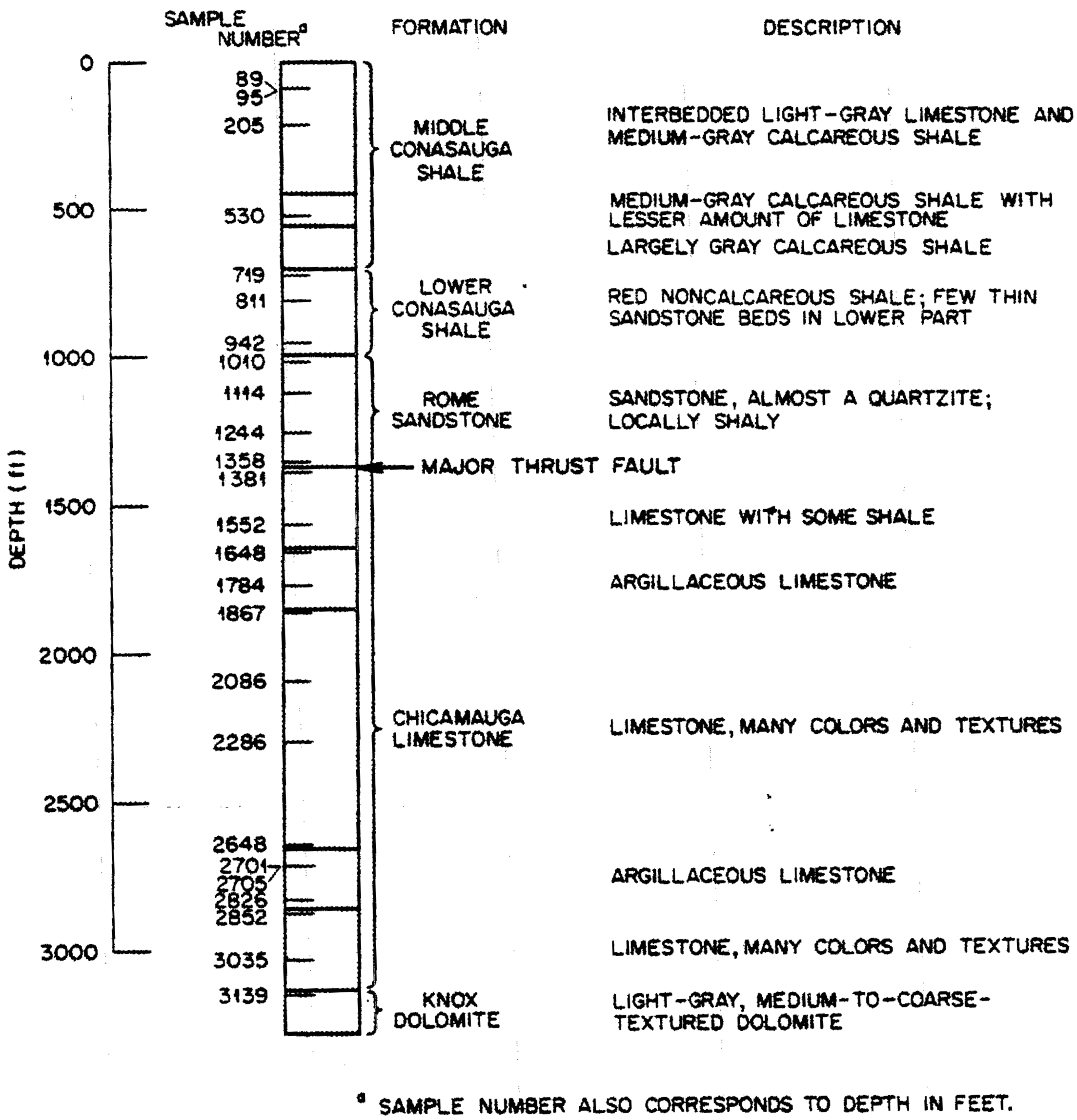

Fig. 2.2. General Description of Core from the "Joy" Test Well. Sample numbers refer to samples selected for mineralogical analysis.

be only local. Unit probably would be suitable for disposal by fracturing where present at greater depth.

544 to 674 ft. Calcareous shale with some interbedded limestone. Bedding coarser and less regular than in overlying unit; locally deformed by drag folds. Probably poorly suited for disposal by fracturing.

674 to 692 ft. Three limestone beds in shale; significant as stratigraphic markers.

Lower Conasauga

692 to 1002 ft. Red noncalcareous shale with a few thin sandy beds in lower part. Bedding is irregular in detail and is locally deformed by minor folds and faults, but both cores and outcrops suggest it will, in general, fracture along the bedding planes. This appears to be one of the best units for disposal by fracturing, particularly where present at somewhat greater depths. This is the unit fractured in all experiments to date.

Rome Formation

1002 to 1360 ft. Well-indurated sandstone, generally thick bedded, locally shaly. Crushed and recemented in lower part. Too massive, hard, and brittle to fracture easily along the bedding; not suited for waste disposal.

Copper Creek Thrust Fault

1360 to 1362 ft. Shaly fault gouge. Soft, but very fine grained and apparently very nearly impermeable.

Chickamauga Limestone

1362 to 1642 ft. Limestone and shaly lime, in part with thin well-developed beds, in part with gradational or poorly developed bedding. With experience, perhaps much of this will be found suitable for disposal by fracturing; at present, only limited sections can be classed as suitable.

1642 to 1847 ft. Shaly limestone with thin well-developed bedding. This unit appears to be well suited to disposal by hydraulic fracturing.

1847 to 1927 ft. Limestone and shaly limestone, generally unfavorable, but includes several short sections suitable for fracturing.

1927 to 2200 ft. Largely limestone, with relatively thick or poorly developed bedding. This general section is probably poorly suited to disposal by fracturing.

2200 to 2366 ft. Limestone and shaly limestone, generally unfavorable, but including several short sections suitable for fracturing.

2366 to 2648 ft. Largely limestone, with relatively thick or poorly developed bedding. This general section is probably poorly suited to disposal by fracturing.

2648 to 2852 ft. Calcareous shale with very uniform well-developed thin beds. This section gives appearance of being excellently suited to disposal by hydraulic fracturing.

2852 to 3126 ft. Limestone, with many variations in texture and bedding, but, in general, relatively thick bedded or indistinctly bedded and therefore believed largely unsuited to disposal by fracturing.

Knox Group

3126 to 3263 ft. Thick bedded, structurally almost massive, coarsely crystalline dolomite. This rock, which probably extends to a depth of about 6000 ft, is clearly quite unsuited to disposal by hydraulic fracturing.

Special Core Analysis Tests

Twenty-five core samples from the Joy test well, identified as to depth in Fig. 2.2, were submitted to Core Laboratory, Inc. (Dallas, Texas) for determination of porosities, crushing strengths, and flow and permeability tests.

In preparation for the tests, plugs were shaped from the available whole-core samples. Where possible, the plugs were cylinders obtained by drilling with a diamond bit. Where this was not possible, cube-shaped plugs were obtained by sawing and carving. Samples to be used for the various flow tests were mounted in plastic. Porosities and air permeabilities were measured. The samples were then evacuated and saturated under 2000 psi pressure with water, and permeabilities to water were then measured.

Samples chosen for the special flow tests with filtrate were placed in a high-pressure core holder while still saturated with water. The filtrate, submitted by Westco Research (Fort Worth, Texas), was then injected into the samples under high pressure and the flow rate observed for several hours.

Samples selected for the crushing strength tests were also evacuated and pressure saturated with water. The sample faces were polished, and the measurements were performed in accordance with ASTM specifications.

Porosities, air permeabilities, and water permeabilities were measured on ten selected samples. The results of these determinations are given in Table 2.1. The very low porosities, even after being dried at 240°F, indicate very hard and compact material. The air permeabilities of the shale, less than 0.005 millidarcy, both vertical and horizontal, indicate very great compaction in both directions. The magnitudes of the differences in the air and water permeabilities are not uncommon for formations of this type. It should be noted that the air permeability values were obtained first, since the samples had been allowed to dry prior to the analysis. It is possible that the resaturation with water did not return the samples to their in situ condition, in which case the actual reservoir permeabilities may be lower than these measured values.

Flow tests using filtrate were performed on six samples after the permeabilities to water had been measured. Several of the samples initially showed permeability to the filtrate. This permeability decreased rapidly, however, resulting in the immeasurably low values given in Table 2.2. The lack of permeability observed using the filtrate is believed to be due to plugging of the pores either on or near the surface of the core with solid material from the filtrate, confirmation that fluid loss additives are not needed.

Table 2.1. Air and Water Permeabilities

Sample No.	Depth (ft)	Horizontal Permeability (millidarcys)		Porosity (%)
		To Air	To Water	
1	155	0.030	0.000105	1.3
2	508	3.2[a]	0.0396[a]	1.1
3	660	0.020	0.000191	0.46
4	719	0.047	0.000030	1.1
5	801	0.024	0.000253	1.9
6	2086	0.0062	0.000253	0.49
7	2701	0.012	0.000273	0.39
8	2705	0.002	0.000075	0.54
9	2826	0.001	0.000576	1.5
10	2852	0.039	0.000552	0.78

[a] Fracture.

Table 2.2. Flow Tests

Sample No.	Depth (ft)	Permeability (millidarcys)	
		To Water	To Filtrate
			$\times 10^{-6}$
11 (horizontal)	942	0.000031	<1.0[a]
12 (horizontal)	2648	0.000078	<1.0[a]
13 (horizontal)	2570	0.000015	<1.0[b]
14 (vertical)	719	$<1.0 \times 10^{-6}$	<1.0[b]
15 (vertical)	2701	0.000017	<1.0[a]
16 (vertical)	2852	0.000012	<1.0[b]

[a] Filtrate from cement containing fluid loss additive.
[b] Filtrate from cement containing no fluid loss additive.

The results of crushing strength determinations are shown in Table 2.3. These data appear normal for core samples of the type analyzed in this study. Compressive strengths of unconfined samples of the shale averaged 1.2×10^4 psi. The shale showed very little reaction and no measurable change in properties when soaked in nitric acid.

Table 2.3. Crushing Strengths

Sample No.	Depth (ft)	Crushing Strength (psi)		
		a	b	c
17	942	4870	7780	3810
18	2648	3400	3500	
19	2705	4500	6900	

[a] Parallel to bedding planes.
[b] Perpendicular to bedding planes.
[c] 45° to bedding planes.

Mineralogical Analysis

We were advised that the injection of significant quantities of actual waste into the shales within the Chickamauga formation above the Knox dolomite might be more suitable than injection into the shales above the Rome formation orthoquartzite. A detailed mineralogical study would provide an indication of the exchange capacity of these potential injection zones. The clays in these shale zones, with relatively high exchange capacities, would serve as natural barriers to the movement of radionuclides and therefore would provide an additional safety factor.

Twenty-five selected samples of the core from the Joy test well were submitted to R. E. Grim (University of Illinois) for detailed analysis of the mineralogy, exchange capacity, and acid-solution components. Figure 2.2 is a general description of the core, showing which samples were selected for Grim's analyses. Table 2.4 contains a list of the samples analyzed and their identity as to depth (in feet) and rock type.

The mineralogy of the core samples is reported in two ways. The Microscopic Examination describes the mineralogy of the entire sample, including the general features of the clay minerals (Appendix 2A). The Clay Analysis covers the results of the analysis by x-ray diffraction of particles 2 μ or less in diameter (Appendix 2B).

In Table 2.4, samples at 719 to 942, 1648 to 1867, and 2648 to 2852 ft, inclusive, represent samples from zones considered suitable for fracturing. In the 719-to-942-ft zone, clay minerals make up the bulk of the samples. Quartz is present in moderate quantities, but calcite is conspicuous by its absence. In the 1648-to-1867-ft zone, the material is principally limestone, with calcite the dominant mineral. The sample taken at 1648 ft represents the more shaly area in this zone; this sample contains about 40% calcite. This mineral distribution is in contrast to the very low calcite content of the shale in the 719-to-942-ft zone. In the 2648-to-2852-ft zone, the calcite and clay minerals occur in moderate amounts. The sample from 2705 ft represents a coarser-textured limestone, and this is reflected by the higher calcite content; the more typical samples of this zone are represented by samples 2701 and 2826. In three zones the clay mineral illite is

Table 2.4. Samples for Core Laboratory from 3263-ft-deep Joy Test Well

Sample Depth (ft)	Analysis
	Middle Part, Conasauga Shale
93	Gray calcareous shale, 80%, with light-gray argillaceous limestone. Bedding irregular, but rock not markedly deformed. Very slightly weathered, but still strong. Typical of mixed shale and limestone of middle Conasauga formation
95	Fine-grained argillaceous limestone, relatively homogeneous. Typical of limestone beds in middle Conasauga. Very slightly weathered, but still strong
155	Fresh, dark-gray calcareous shale; typical. Protected from moisture loss
197	Medium-grained sandy textured limestone. Very little deformed. Typical of fresh limestone at this depth. Few veinlets of secondary calcite
245	Dark-gray, homogeneous calcareous shale. Not deformed. Typical of pure shale at this depth. Dip 45°
508	Gray calcareous shale, internally deformed, but not badly folded. Has been protected from moisture loss
533	Dark-gray, homogeneous calcareous shale. Typical of pure shale. Dip 30°. Not deformed
535	Dark-gray calcareous shale; similar to above but protected from water loss
	Pumpkin Valley Member of Conasauga Shale
660	From well 15 west. Typical red shale with white "sandy" streaks and thin (0.1 in.) beds of glauconite. Not deformed
719	Typical red shale with a few light-colored "sandy" streaks (20%) and possibly a little glauconite. Dip 15°. Very little deformed. Secondary calcite veinlets
801	Typical red shale similar to above
942	Red shale, apparently much crushed and original bedding destroyed, but completely recompacted; now appears nearly massive
	Rome Sandstone
1014	Hard, white to very light-gray sandstone or quartzite, typical of upper Rome formation. Dip 10°
1111	Pinkish, slightly argillaceous hard sandstone with a very few thin shale partings. Dip 45°, but not deformed. Typical of much material in Rome formation
1242	Hard silty or sandy shale, apparently much crushed and original bedding destroyed, but recompacted and solid. Dark gray to black. Typical of sandy shale in Rome formation
1346	Hard, grayish bedded sandstone; dip 50°. Typical of sandstone in lower Rome

Table 2.4. (Continued)

Sample Depth (ft)	Analysis
	Chickamauga Limestone
1366	Calcareous red shale, hard, massive. Probably top of Chickamauga just below fault. Breaks on 30° dip
1501	Very dark-gray calcareous shale. Bedding indistinct, somewhat deformed internally, but breaks evenly along bedding; dip 25°. Very fine grained, almost massive in appearance. Characteristic of dark shales in Chickamauga
1515	Dark-red very fine-grained calcareous shale, nearly massive in general appearance, as there is no color or textural banding to show bedding; however, rock breaks evenly along bedding planes. Dip 15°
1552	Very fine-grained medium- to light-gray limestone, typical of "lithographic" limestone in well log. Only very slight internal deformation. Bedding is distinct and is not folded or sheared
1565	Very light-gray coarse, irregular textured limestone, probably formed largely from shell fragments which have been broken and recrystallized, and thin (0.1-in.) beds and partings of gray calcareous shale. "Podded" texture, but not conspicuously folded or sheared. "Podding" may well be original texture. Typical of coarser textured limestones in middle Chickamauga
1648	Dark gray very fine-grained massive-appearing calcareous shale. Breaks cleanly on 15° dip. Typical of dark fine-grained shales in Chickamauga
1668	Almost white coarse-textured limestone, probably fossiliferous. Dip uncertain, about 20°
1819	Medium-dark-gray very fine-grained limestone with faint brownish tinge, "lithographic." "Podded" with thin irregular beds or partings of darker shale. Almost certainly original texture
1864	Light-gray coarse-textured fossiliferous limestone; compact, hard, not deformed. Contains many pieces of broken shell and oolites
1946	Medium- to light-gray limestone, medium grained, with thin (0.1-in.) beds and irregular partings of gray shale. "Podded" but not deformed or folded. Podding may well be original texture, but uncertain
2076	Dark-gray hard limestone with many small white shell fragments scattered. Called "spotted limestone" in well log. Bedding absent or indistinct
2086	Dark-red, almost massive calcareous shale. Typical of minor disposal unit in Chickamauga
2093	Conspicuously banded thin-bedded alternating red shale and pink to white fine-grained, sandy textured limestone

Table 2.4. (Continued)

Sample Depth (ft)	Analysis
2278	Medium-gray limestone and dark-gray shale in alternating beds ranging from 0.1 to 1.0 in. thick. Somewhat "podded." Fossil brachiopods at this general horizon. Sample is typical of much interbedded limestone and shale. No clear signs of internal deformation; podding may well be original structure
2388	Fine- to medium-grained light-gray sandy textured limestone, locally cherty. Moderately distinct thin beds due to color variations and shale partings
2474	White, pure, very coarse-textured crystalline limestone; almost a marble. Typical only of certain minor beds
2476	Very fine-grained, medium- to light-gray, faintly brownish limestone – "lithographic" – with a few very thin darker streaks or partings. Hard and brittle; not internally deformed or folded
2570	Very dark-gray fine-grained argillaceous limestone. Bedding does not show on surface, but rock breaks cleanly on bedding planes. Rock looks massive
2648	Dark-gray fine-grained argillaceous limestone. Looks massive, but rock breaks cleanly on bedding. Color changes below to pinkish. Top of proposed main disposal unit
2701	Dark-red very fine-grained argillaceous limestone or calcareous shale. Typical of much of main disposal unit. Looks massive but breaks cleanly along bedding planes
2705	Banded pink and white, fine granular textured limestone; looks less argillaceous than 2701, but occurs interbedded with material like that at 2701 in roughly equal amounts. Hard, brittle, breaks cleanly along bedding, which shows as prominent color bands about 0.1 in. thick or so. Very little, if at all, deformed. Typical of much of main disposal unit
2826	Dark-red argillaceous limestone or calcareous shale; very fine grained. Looks massive, but breaks cleanly along bedding planes. Typical of much of rock in main disposal unit
2852	Medium-dark-gray medium-fine-grained limestone; generally massive in appearance but contains a few thin lighter-gray beds, 0.01 in. thick or so. Breaks cleanly along bedding. Lower part of proposed main disposal unit
3035	Two samples. One red and one green, very fine-grained calcareous shale or possibly argillaceous limestone. Shows no bedding, but breaks cleanly along bedding. Not typical of general section here; most is fine to coarse cherty limestone

most abundant in the deepest and in the shallowest zones. Kaolinite and chlorite make up a substantial portion of the minerals in the shallow zone (719 to 924 ft).

Two formations considered unsuitable for fracturing are the Rome sandstone and the Knox dolomite. The Rome sandstone is represented by samples from 1010 through 1360 ft. The very hard sandstone samples (1010 and 1114 ft) differ from the more argillaceous sandstone samples (1244 and 1358 ft) by their higher quartz content. Associated with the higher quartz content is feldspar, present up to 10% in this formation. In the Knox dolomite formation, represented by sample 3139, the calcareous mineral is the only one identified positively.

Data are also reported on the exchange capacities and acid-soluble fractions of the core samples. These values are shown in Table 2.5. Exchange capacities range from 5.4 to 29.4 meq/

Table 2.5. Exchange Capacity and Acid-Soluble Components

Sample Depth (ft)	Exchange Capacity (meq/100 g)	Percentage of Acid-Soluble Components
29	13.1	54.1
95	22.99	27.3
205	7.3	26.4
530	21.05	1.2
719	8.12	5.3
811	9.94	9.6
942	15.44	7.8
1010	5.76	6.4
1114	7.50	4.3
1244	10.35	5.7
1358	29.4	0.01
1381	5.9	44.9
1552	10.80	77.5
1648	7.32	34.6
1784	9.84	78.8
1867	13.17	90.7
2086	11.87	30.7
2286	9.43	70.7
2648	7.17	48.6
2701	16.0	33.0
2705	18.15	64.7
2826	7.48	23.5
2852	15.85	25.4
3035	13.35	28.9
3139	5.44	89.2

100 g. The lowest value represents the core with extremely high calcite and dolomite content (3139 ft); the highest value is from the core at 1358 ft, which is in the thrust-fault zone.

In general, the lower exchange capacities correspond to lower clay mineral content. Of the minerals identified, quartz, calcite, dolomite, and feldspars have little or no exchange capacity; kaolinites have low capacities (1 to 10 meq/100 g); illites and chlorites have moderate capacities (15 to 25 meq/100 g); and montmorillonites have high capacities (100 meq/100 g). Studies of several illites here showed that their exchange capacities can range from 12 to 30 meq/100 g, and, since illite is the dominant clay mineral in the core, it is suspected that the exchange capacity variations observed in samples mineralogically similar may be due to differences in the nature of the illite in the core.

The percentage of acid-soluble components is a measure of the calcite content in geologic formations. These analyses show that samples from the shallow zone (719 to 942 ft) contain very little calcite, whereas considerable calcite is found in the two deeper zones considered favorable for fracturing. Two samples with about 90% acid-soluble components are from a fossiliferous zone (1867 ft) and a dolomite zone (3139 ft). It was somewhat surprising that the dolomite sample should show such high acid-soluble content, since dolomites are known to be less soluble than calcite. Generally, however, the concentrations of acid-soluble components agree well with estimates of the calcite content based on optical and x-ray diffraction techniques.

On the basis of clay mineralogy, both the shallow (719 to 942 ft) and the deepest (2648 to 2852 ft) zones appear to be favorable for fracturing because of their high illite content. Illite is highly selective for cesium sorption and will serve as a barrier to the movement of radiocesium if grout sheets are subject to leaching.

Geothermal Measurements

Detailed temperature surveys of the Joy test well were made by W. H. Diment and E. C. Robertson of the USGS in December 1961 and March 1962.[2] Temperature measurements were also made in the Joy well in October 1962, after it had been cased down to 2900 ft. There were only minor changes in the temperatures in the Joy No. 1 well between these dates. The temperature gradients were compared with the thermal conductivity of rock samples from the core of the test well, and a computation was made of the rate of heat flow from the earth's interior. Diment and Robertson obtained a provisional value of 0.73 ± 0.04 microcalorie cm^{-2} sec^{-1}, a relatively low rate, but this value may be revised as the result of subsequent observations.

Figure 2.3 is a plot of the temperature in the Joy well to a depth of 2900 ft. The measurements are probably correct to within less than 0.1°F, but they may not represent the normal thermal gradient. Subsequent to the last temperature measurements (October 1962), the water level in the casing in the Joy well was found to be dropping slowly, whereas it had been assumed that the

[2]W. H. Diment and E. C. Robertson, "Temperature, Thermal Conductivity and Heat Flow in a Drilled Hole near Oak Ridge, Tennessee," *J. Geophys. Res.* 68, 5035 (1963). (Earlier unpublished report gives specific relation of temperature gradient to depth of groundwater movement.)

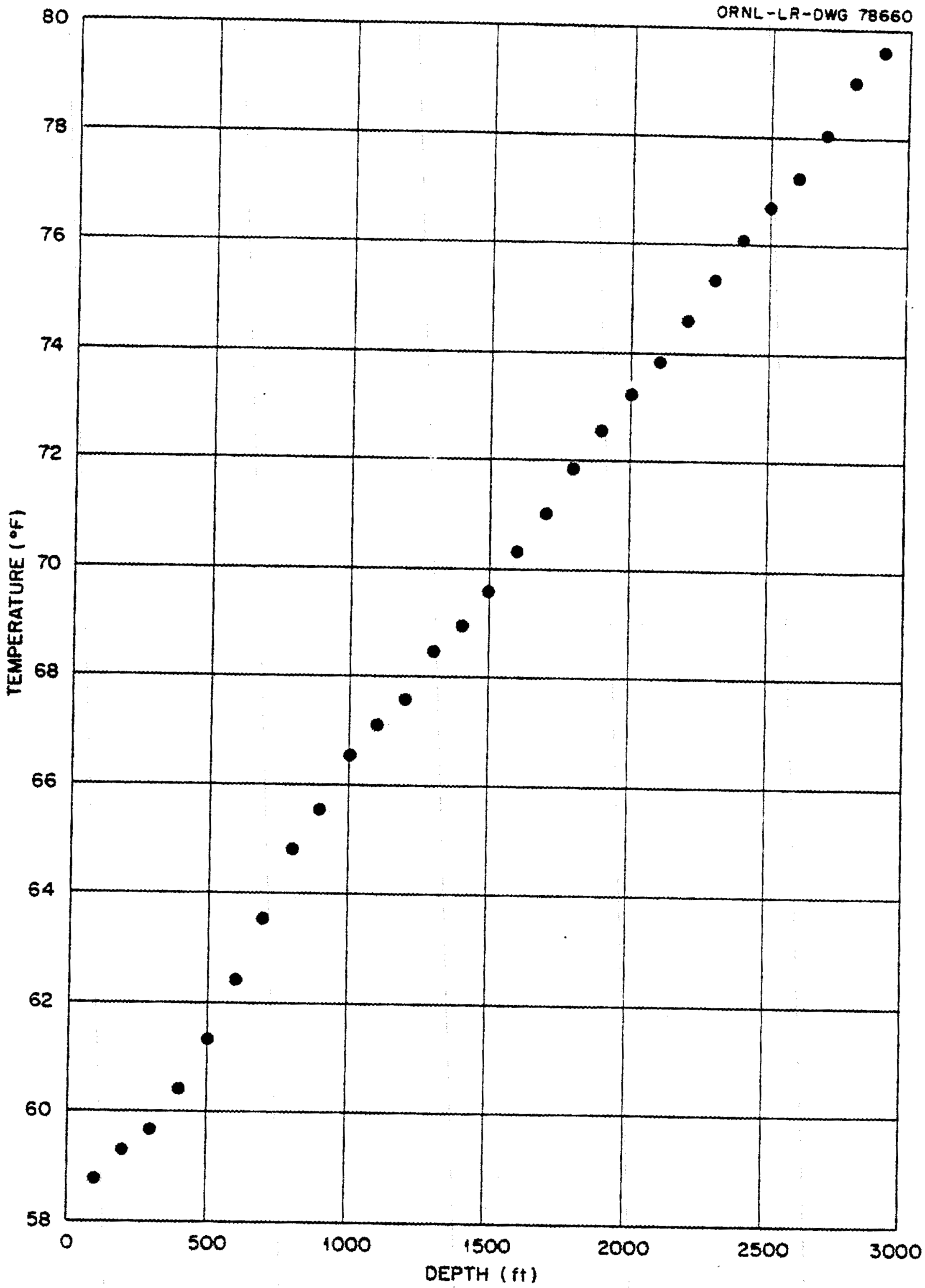

Fig. 2.3. Temperature Measurements in the "Joy" Well (October 1962). Measurements made by USGS.

water was stagnant. This downward flow of cooler surface water into the warmer, deeper horizons has to some unknown degree locally reduced the normal temperature gradient, so that some minor adjustment of the computed rate of heat flow will be required.

The temperature gradient in another well at the site of the second fracturing experiment, from about 400 ft to the bottom of the well at 1025 ft, is very similar to that measured in the same interval in the Joy well, although the temperatures in the other well averaged about 0.3°F higher. This suggests that the departures from the normal thermal gradient in the Joy well are less than 1°F and that the reported temperatures can be used to determine the pumping and setting times of the waste-cement mixes under development.

The marked differences in the thermal gradients in the two wells down to a depth of 200 ft were explained by Diment and Robertson as probably due to the slow circulation of groundwater down to this depth. The disturbances in the gradient caused by this circulation down to 200 ft slowly disappear in the interval between 200 and 400 ft. There is no reason to believe that there is any groundwater movement below 200 ft, although the data do not entirely rule out this possibility.

Abnormally Low Pressures in Depth in the Joy Well

For the first year after the Joy well was drilled, there was no way to determine that water was flowing out the bottom of the well into the deeper formations; the water level in the then uncased well was maintained by its interconnection at the surface with the main water table. However, in June 1962 a $1\frac{1}{4}$-in. casing was cemented into the well down to a depth of 2900 ft, leaving open the interval below 2900 ft and the bottom of the well at 3263 ft. This open-hole section is in the lower part of the Chickamauga limestone and the upper part of the Knox dolomite, all rock that appears to have no significant permeability or porosity. These rocks, however, may contain minute fractures, most of which would be expected to be parallel to the bedding planes.

The temperature measurements made in October 1962 were surprising, because they showed that the water level in the casing was 100 to 150 ft below land surface. Following some preliminary tests, the casing was filled to the surface on October 16. Figure 2.4 shows the subsequent water level in the well. Soon this level was below that of Watts Bar Dam, which determines the lowest possible level of the water table for a wide surrounding area, and it became evident that the water was being taken into the lower Chickamauga and upper Knox as the result of an abnormally low liquid pressure in these formations.

This low pressure might conceivably be attributed to the elastic expansion of these rocks due to removal of overburden during the last few million years. However, this process appears to be far too slow, compared with the possible rate of movement of water down through the overlying cover rocks, impermeable as this cover appears to be. Differences in chemical concentration, in temperature, and in electric potential can cause very slow fluid flow through rocks of low permeability by a process which is, or closely resembles, osmosis. The significance of this abnormally low fluid pressure in these deep horizons is that there can be no possible pathways of appreciable permeability between them and the water table.

000480

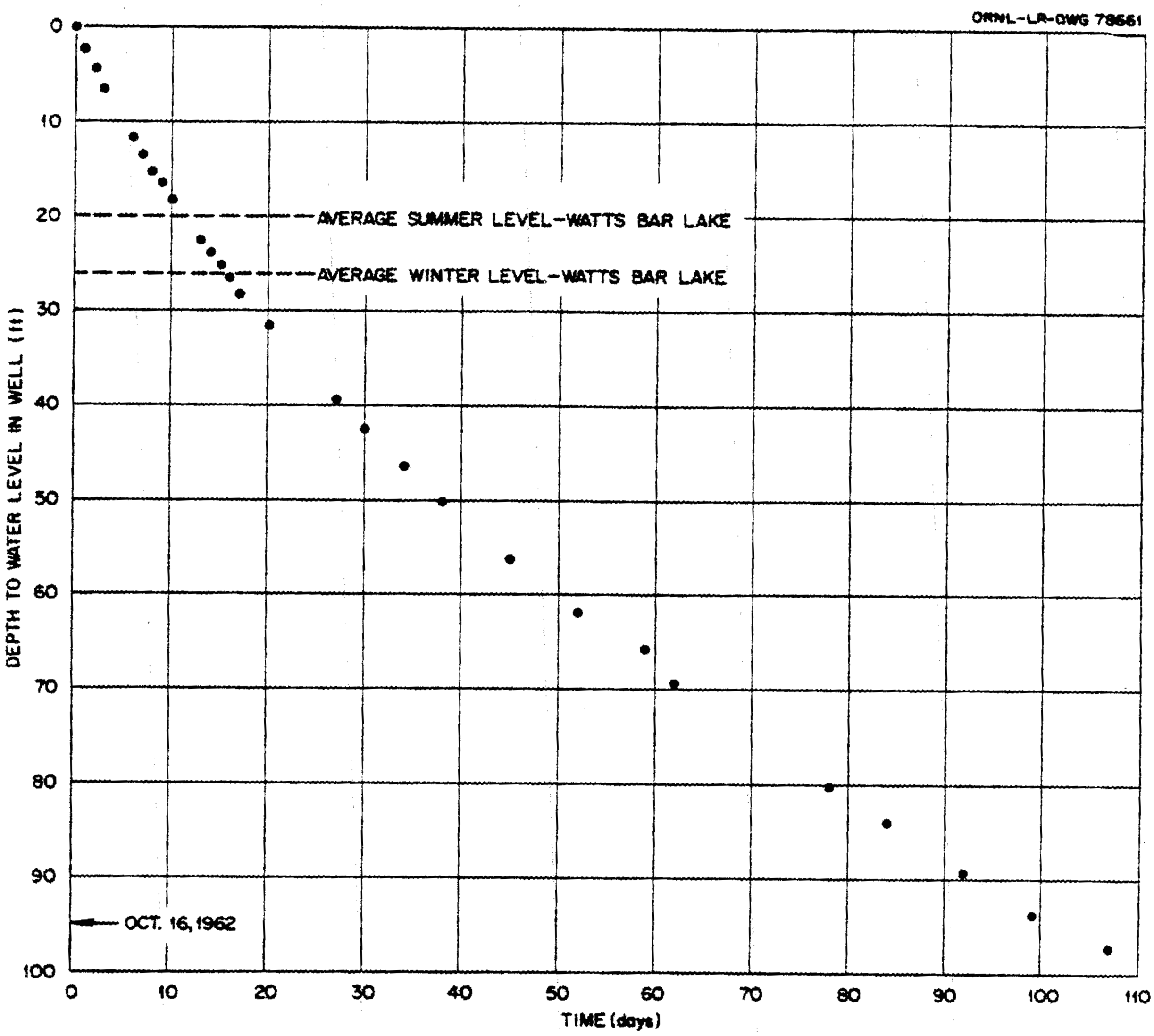

Fig. 2.4. Drop in Water Level in Cased "Joy" Well.

Appendix 2A

RESULTS OF MICROSCOPIC EXAMINATION

By R. E. Grim

89 Mostly extremely fine calcite – less than 10 μ, few particles to 40 μ. Quartz to 40 μ. Clay minerals too small to be seen individually – in aggregate particles with fine calcite.

95 Calcite, extremely fine – mostly less than 10 μ – few particles to 40 μ. Quartz to 40 μ. Clay minerals too small to be seen individually – in aggregates many of which show aggregate orientation and high birefringence of micas. Aggregates have only a little calcite, as if clay minerals and calcite not very intimately mixed.

205 Calcite, mostly 10 to 50 μ. Quartz to 40 μ. Glauconite to 80 μ is common. Clay minerals in random oriented aggregates – particles too small to be seen individually – little mixing with calcite.

530 Calcite to 40 μ. Quartz to 40 μ – mainly very fine – less than 20 μ. Clay mineral flakes to 80 μ – many flakes to 40 μ. Some oriented aggregates. Many green chloritic flakes. Few glauconites to 80 μ. Dirty appearance probably due to organics.

719 Calcite trace to 40 μ. Quartz to 80 μ. Rare grains of glauconite to 80 μ. Clay minerals in flakes to 20 μ – many flakes to 10 μ. Aggregates, often showing aggregate orientation. Green flakes of chlorite are quite abundant. Dirty appearance due to organic material.

811 Calcite trace to 40 μ. Quartz to 100 μ. Glauconite common to 80 μ. Clay minerals to about 20 μ – mostly very fine, in dirty-appearing (due to ferric iron) aggregates.

942 Quartz to 100 μ. Mica to 40 μ – mostly less than 10 μ. Few clay mineral aggregates – mostly dispersed flakes. Few grains of glauconite. Few green flakes of chlorite. Dirty appearance perhaps due to organics.

1010 Quartz to 100 μ unsorted. Trace calcite to 40 μ. Feldspar to 80 μ. Clay minerals in colorless individual flakes to 20 μ.

1114 Quartz to 100 μ – unsorted. Feldspar to 100 μ. Clay mineral, colorless flakes to 30 μ – no aggregates. Rare glauconite to 40 μ.

1244 Calcite, trace to 30 μ. Quartz to 150 μ. Feldspar to 150 μ. Clay minerals, many particles to 20 μ – some larger flakes to 40 μ. Green glauconite-looking particles to 80 μ – some few oriented aggregates with dirty appearance, probably due to organics.

1358 Calcite to 50 μ. Quartz to 50 μ. Clay minerals to 30 μ but mostly too small to be seen individually – in aggregates with little preferred orientation, dirty in appearance, probably due to ferric iron. Clay mineral has fairly high birefringence.

1381 Calcite to 20 μ but mostly very fine, less than a few microns. Quartz exceedingly rare and fine – less than 20 μ. Clay mineral in particles too small to be seen individually and mixed with calcite. No clay mineral aggregates.

1552 Calcite, substantially all less than 10 μ. No other components definitely determinable.

1648 Calcite to 40 μ – mostly less than 10 μ. Quartz less than 20 μ. Clay minerals in individual colorless flakes to 20 μ – mostly less than 10 μ. No glauconite and no clay mineral aggregates.

1784 Calcite to 40 μ – mostly less than 10 μ. No other components definitely visible. Any quartz extremely fine. Any clay minerals in individual flakes less than about 10 μ.

1867 Calcite to 40 μ, but mostly less than 10 μ. No quartz or clay mineral can be identified definitely.

2086 Calcite to 30 μ, but mostly less than 10 μ. Quartz to 30 μ. Clay minerals less than 10 μ, mostly too small to be seen individually. Many dirty-appearing (probably due to ferric oxide) aggregates of calcite and clay minerals without aggregate orientation.

2286 Calcite to 40 μ, mostly less than 10 μ. No other components definitely determinable. Any clay minerals or quartz extremely small (– 20 μ). No clay mineral aggregates.

2648 Calcite to 50 μ, but mostly less than 10 μ. Quartz to 40 μ. Clay minerals in individual flakes to 20 μ, but mostly less than 10 μ in individual flakes and aggregates with calcite. Aggregates have little preferred orientation. Clay mineral has high birefringence.

2701 Calcite to 40 μ. Clay mineral to 30 μ in individual flakes and random aggregates – all red ferric iron stained.

2705 Calcite to 80 μ unsorted. Quartz to 80 μ. Clay mineral, few flakes to 80 μ – some green chlorite. Most of clay minerals is colorless and less than 10 μ in individual flakes and in random aggregates with the calcite.

2826 Calcite to 40 μ unsorted. Quartz to 40 μ unsorted. Clay mineral in flakes to 20 μ, but mostly less than 5 μ – in individual flakes and dirty-appearing aggregates (probably due to ferric iron) with little preferred orientation. Clay mineral has high birefringence.

2852 Calcite to 40 μ – mostly less than 10 μ. Quartz to 40 μ. Clay mineral in individual flakes less than 10 μ and aggregates with the calcite. Clay mineral colorless and highly birefringent.

3035 Calcite to 80 μ, but mostly less than 10 μ (unsorted below 40 μ). Quartz to 80 μ. Clay mineral in flakes to 20 μ but mostly less than 10 μ in individual and dirty-appearing aggregates with calcite. Little preferred orientation and high birefringence.

3139 Carbonate to 100 μ – much very coarse. No other component can be identified definitely.

CLAY ANALYSIS

By R. E. Grim

Sample No.	Calcite	Quartz	Illite	Kaolinite	Chlorite	Miscellaneous
89	60%; mostly +2 μ; 1/3, −2 μ; 1/4, −1 μ	10%; mostly −2 μ; 1/3, −1 μ	15%; highly degraded; all −2 μ; 1/3, −1 μ; mixture di- and trioctahedral	5%; mostly −1 μ	10%; highly degraded; mostly −1 μ	
95	20%; mostly −2 μ; 1/2, 1 μ	15%; mostly −2 μ; 1/3, −1 μ	35%; moderately degraded; mostly −1 μ; dioctahedral	10%; mostly −1 μ	15%; highly degraded; mostly −1 μ	Trace feldspar; trace dolomite
205	35%; mostly −2 μ; 1/3, −1 μ	25%; 1/2, −2 μ; 1/3, −1 μ	20%; slightly degraded; mostly −1 μ; mixture di- and trioctahedral	5%; mostly −1 μ	10%; highly degraded; mostly −1 μ	5% feldspar
530	Trace	25%; mostly +2 μ; 1/3, −2 μ; 1/4, −1 μ	40%; moderately degraded; all −2 μ; mostly −1 μ; dioctahedral	15%; mostly −1 μ	15%; highly degraded; mostly −1 μ	Trace feldspar and montmorillonite
719		25%; mostly +1 μ; 1/3, −2 μ; 1/4, −1 μ	45%; moderately degraded; all −2 μ; mostly −1 μ; dioctahedral	15%; mostly −1 μ	15%; highly degraded; mostly −1 μ	Trace feldspar and montmorillonite
811	Trace	20%; mostly +1 μ; 1/3, −2 μ; 1/4, −1 μ	45%; moderately degraded; all −2 μ; mostly −1 μ; mixture di- and trioctahedral	15%; mostly −1 μ	15%; highly degraded; mostly −1 μ	Trace feldspar and montmorillonite
942		30%; mostly +2 μ; 1/4, −2 μ; trace, −1 μ	40%; slightly degraded; all −2 μ; mostly −1 μ; dioctahedral	10%; mostly −1 μ	20%; moderately degraded; mostly −1 μ	Trace feldspar; montmorillonite
1010	5%; mostly −1 μ	60%; mostly +2 μ; 1/3, −2 μ; 1/4, −1 μ	15%; slightly degraded; all −2 μ; mostly −1 μ	5%; mostly −1 μ	5%; moderately degraded; mostly −1 μ	10% feldspar
1114		60%; mostly +2 μ; 1/3, −2 μ; 1/4, −1 μ	20%; slightly degraded; all −2 μ; 1/2, −1 μ; dioctahedral	5%; mostly −1 μ	5%; moderately degraded; mostly −1 μ	10% feldspar

Sample No.	Calcite	Quartz	Illite	Kaolinite	Chlorite	Miscellaneous
1244	Trace	35%; mostly $+2\ \mu$; $\frac{1}{4}$, $-2\ \mu$	35%; slightly degraded; all $-2\ \mu$; $\frac{1}{2}$, $-1\ \mu$; dioctahedral	10%; mostly $-1\ \mu$	15%; moderately degraded; mostly $-1\ \mu$	
1358	10%; mostly $+2\ \mu$	20%; mostly $+2\ \mu$; $\frac{1}{3}$, $-2\ \mu$; $\frac{1}{4}$, $-1\ \mu$	45%; moderately degraded; all $-2\ \mu$; $\frac{1}{2}$, $-1\ \mu$; dioctahedral	Trace	10%; highly degraded; mostly $-1\ \mu$	5% feldspar; 10% mixed layer
1381	50%; mostly $+2\ \mu$; $\frac{1}{3}$, $-2\ \mu$	10%; mostly $+2\ \mu$; $\frac{1}{3}$, $-2\ \mu$; $\frac{1}{4}$, $-1\ \mu$	25%; moderately degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture di- and trioctahedral	5%; mostly $-1\ \mu$	10%; well degraded; mostly $-1\ \mu$	
1552	80%; mostly $+2\ \mu$; $\frac{1}{4}$, $-2\ \mu$	5%; mostly $+2\ \mu$	10%; highly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture di- and trioctahedral	Trace	5%; well degraded; mostly $-1\ \mu$	Montmorillonite
1648	40%; mostly $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	15%; mostly $-2\ \mu$ $\frac{1}{3}$, $-1\ \mu$	25%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture of di- and trioctahedral	10%; mostly $-1\ \mu$	10%; moderately degraded; mostly $-1\ \mu$	Montmorillonite
1784	85%; mostly $+2\ \mu$	5%; only trace $-2\ \mu$	5%; well degraded; all $-2\ \mu$	Trace; mostly $-1\ \mu$	5%; well degraded; mostly $-1\ \mu$	5% mixed layer
1867	80%; mostly $+2\ \mu$; $\frac{1}{3}$, $-2\ \mu$	5%; only trace $-2\ \mu$	10%; entirely a random mixed-layer assemblage of three-layer clay minerals			10% dolomite
2086	35%; mostly $-2\ \mu$	15%; about $\frac{1}{2}$, $-2\ \mu$; about $\frac{1}{4}$, $-1\ \mu$	30%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; dioctahedral	5%; mostly $-1\ \mu$	10%; slightly degraded; mostly $-1\ \mu$	5% dolomite
2286	70%; mostly $+2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	5%; mostly $+2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	15%; moderately degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture di- and trioctahedral	5%; mostly $-1\ \mu$	5%; well degraded; mostly $-1\ \mu$	Trace dolomite
2648	55%; mostly $-2\ \mu$; $\frac{1}{2}$, $-1\ \mu$	10%; mostly $+2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	20%; moderately degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture of di- and trioctahedral	5%; mostly $-1\ \mu$	10%; well degraded; mostly $-1\ \mu$	10% dolomite

Sample No.	Calcite	Quartz	Illite	Kaolinite	Chlorite	Miscellaneous
2701	20%; mostly $-2\ \mu$; $\frac{1}{2}$, $-1\ \mu$	15%; about $\frac{1}{2}$, $-2\ \mu$; $\frac{1}{4}$, $-1\ \mu$	40%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture di- and trioctahedral	5%; mostly $-1\ \mu$	10%; well degraded; mostly $-1\ \mu$	10% dolomite; montmorillonite
2705	60%; mostly $+2\ \mu$; $\frac{1}{3}$, $1\ \mu$	15%; mostly $+2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	10%; well degraded; all $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$; mixture of di- and trioctahedral	Trace; mostly $-1\ \mu$	5%; well degraded; mostly $-1\ \mu$	10% dolomite
2826	30%; mostly $-2\ \mu$; $\frac{1}{3}$, $1\ \mu$	20%; about $\frac{1}{2}$, $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	25%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture di- and tri-octahedral	5%; mostly $-1\ \mu$	10%; well degraded; mostly $-1\ \mu$	10% dolomite
2852	30%; mostly $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	15%; about $\frac{1}{2}$, $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	30%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mostly dioctahedral, some trioctahedral	5%; mostly $-1\ \mu$	10%; slightly degraded; mostly $-1\ \mu$	10% dolomite
3035	30%; mostly $-2\ \mu$; $\frac{1}{3}$, $-1\ \mu$	15%; mostly $-2\ \mu$; $\frac{1}{2}$, $-1\ \mu$	25%; slightly degraded; all $-2\ \mu$; mostly $-1\ \mu$; mixture of di- and trioctahedral	5%; mostly $-1\ \mu$	10%; slightly degraded; mostly $-1\ \mu$	15% dolomite
3139	80%; mostly $+2\ \mu$	5%; mostly $+2\ \mu$	15%; entirely a random mixed-layer assemblage of three-layer clay minerals			35% dolomite; mostly $+2\ \mu$; $\frac{1}{4}$, $-2\ \mu$

Notes: The quantitative differentiation of kaolinite and chlorite is difficult. In every case the value for kaolinite is perhaps high and for chlorite it may be low.

Particle sizes are those following dispersion in water.

Trace is less than 5%.

Unless so indicated, it is impossible to determine polymorphic form of illite, that is, whether dioctahedral (muscovite) or trioctahedral (biotite), and form of dioctahedral types.

3. Fracturing Experiments 1 and 2

The review of the petroleum industry's original suggestion by a committee of the Earth Science Division of the National Academy of Sciences–National Research Council brought to our attention a long-standing controversy in the petroleum industry as to the orientation and geometry of the fractures formed as the result of various oil-field operations and, particularly, whether it is possible to control, by the use of special methods or equipment, the orientation of the fractures that will be formed at a particular site.[1–5] The aspects of this complex problem that are most pertinent to waste disposal are as follows:

When a fluid which does not penetrate the wall rock is pumped into an uncased well, the pressure expands the diameter and hence the circumference of the well, and a vertical fracture or fractures will form and radiate out from the well bore. However, if the well is cased, as the disposal wells will be, this outward pressure will be contained by the casing, and this cause of vertical fracturing will not apply.

If the fluid escapes from the well bore, or through openings in the casing, into a comparatively permeable formation, the fluid pressure in the pores of a considerable volume of the formation will be increased, and, if increased sufficiently, a fracture or fractures will form normal to the smallest compressive stress in the rock. In areas of recent or current normal faulting (i.e., faulting which accompanies a local lengthening of the crust), this least stress will be horizontal and normal to the faults. This appears to be the case in many oil fields, and, although no comprehensive statistical study has been made, some petroleum geologists believe that more vertical than horizontal fractures have been formed in oil wells. Oil fields, however, do not necessarily represent an average sample of sedimentary rocks. In areas where reverse faults or folds show recent compression of the rocks, the least stress at any point in depth will probably be the pressure due to the weight of the overburden, and the fracture will be horizontal. In areas of relatively

[1]M. K. Hubbert and W. W. Rubey, "Role of Fluid Pressure in Mechanics of Overthrust Faulting," *Geol. Soc. Am. Bull.* 70, 115 (1959).

[2]M. K. Hubbert and D. G. Willis, "Mechanics of Hydraulic Fracturing," *J. Petrol. Technol.* 9, 153 (1957).

[3]J. M. Cleary, "Hydraulic Fracture Theory, Part I. Mechanics of Materials" (Circular 251) and "Part II. Fracture Orientation and Possibility of Fracture Control" (Circular 252), Illinois Geol. Survey, Urbana, Ill., 1958.

[4]R. C. Clark and J. J. Reynolds, "Vertical Hydraulic Fracturing," *Oil Gas J.* 53, 104 (1954).

[5]C. D. Fraser and B. E. Pettitt, "Results of Field Test to Determine the Type and Orientation of a Hydraulically Induced Formation Fracture," *J. Petrol. Technol.* 14, 463 (1962).

undeformed rock, and these will probably include those best suited for waste disposal by hydraulic fracturing, the state of stress of the rock in depth will be uncertain; this is one of the reasons why each proposed disposal area will have to be individually tested. Particularly in the case of a permeable rock, the state of stress in the rock will be of great importance in determining the orientation of any fractures formed in it.

A controversial question in the petroleum industry is whether horizontal fractures can be formed by hydraulic pressure in the fracture less than that due to the weight of the overburden. A horizontal fracture of limited extent may be formed by compression of the overlying and underlying rock, which would seem to require an increase in pressure above that previously present. As the rock at any point must, in general, support the weight of the overlying rock, this would seem to require a fluid pressure in the fracture greater than that due to the weight of the overburden. An extensive horizontal fracture will lift the overlying rock, and for this a pressure at least equal to that due to the weight of the overburden would seem to be required.

Where a fracture is observed to form at a pressure less than the weight of the overburden, one of the principal horizontal stresses in depth can be presumed to be low, as in an area of normal faulting, and a vertical fracture almost certainly has been formed by compressing the rock normal to this stress. However, this straightforward argument is not universally accepted by the petroleum industry because there have been a number of instances, largely undocumented, in which fractures formed at what appeared to be less than overburden pressure intersected several adjacent wells. This could hardly be the result of a vertical fracture, although some geologists have argued that the relief of pressure in the rock near a well, resulting from the drilling of the well, could "guide" a vertical fracture into the well. More reasonable, but still tentative, possible explanations are given below.

Pressure measurements made at the wellhead, as is almost universally the case in the petroleum industry, have been shown to be an unreliable measure of the pressure in the fracture,[6] so that some, but hardly all, of the apparent anomalies may be the result of inaccurate field data.

Differential compaction of the rock may result in an uneven distribution of the load, and the fracture may follow the path of least resistance, parting the rock where the pressure is less than average.

A thin relatively permeable formation, underlain and overlain by a less permeable plastic rock such as shale, may not fracture like a brittle rock, to which the laws of Newtonian mechanics are more rigorously applicable. For example, during well drilling some of the shale may squeeze into the well bore, locally reducing the pressure of the overburden on the permeable formation, which could then be fractured at a lower pressure.[7]

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[6] J. K. Godbey and H. D. Hodges, "Pressure Measurements During Formation Fracturing Operations," paper presented at Annual Meeting AIME, Dallas, Tex., Oct. 6, 1957.

[7] Yu. P. Zheltou and S. A. Khristianouich, "The Hydraulic Fracturing of an Oil-Producing Formation," *Izv. Akad. Nauk SSSR, Otd. Tekhn. Nauk*, No. 5, 3 (1955); Associated Tech. Services, Translation RJ-742.

None of these explanations can yet be accepted, and for our purposes it has been assumed that the formation and propagation of horizontal fractures requires a fluid pressure in the fracture greater than that due to the weight of the overburden. This assumption formed the starting point for the fracturing tests with water, which might be used to screen out areas with geology unsuited for disposal by hydraulic fracturing. These tests, however, included not only relatively reliable measurements of the pressure at the surface during the fracturing but also the pressure as a function of time after the fracture had been completed and the volume of water recovered when the well was later permitted to flow. If the results of a similar test in another area closely resembled those obtained at Oak Ridge, where the fractures are known to follow the gently dipping bedding planes, the presumption would be that the fractures in the other area were also essentially horizontal.

All the fracturing pressures at Oak Ridge have been appreciably greater than that due to the weight of the overburden, and so all the fractures may be presumed to have followed the bedding planes.

FIRST FRACTURING EXPERIMENT (OCTOBER 1959)

Objectives

The disposal of radioactive wastes cannot be based on presumption, and so three experimental injections were made into the shale at Oak Ridge, and the fracture pattern was determined for each. The first experiment was intended to test the testing method, that is, to see if a cement grout tagged with a radioactive tracer could be injected into the shale by hydraulic fracturing and if core drilling and gamma-ray logging could be used to map the fracture formed. The site selected for this first experiment was in the lower Conasauga shale, near the contact between the Pumpkin Valley member and the Rutledge. The injection well, about 300 ft deep, had been drilled in connection with earlier work at the site which had also included some shallower core drilling and a shallow 700-ft-long cut with a bulldozer from which had been constructed a detailed north-south structure section. (Unless otherwise specified, the directions used in the following sections of this report will be the Oak Ridge coordinate system, in which "north" is 34° 13′ west of true north. Although devised for other reasons, the plant coordinates have the advantage that "north" is directly up dip and that "east" and "west" are on the line of strike.) The injection well started in the Rutledge and passed into the Pumpkin Valley at a depth of about 100 ft. At first the change in color from gray to red was used to locate this contact, but later all stratigraphic correlations were referred to the three limestone beds, each roughly 5 ft thick and spanning a vertical interval of about 20 ft, which form a much more reliable guide to this contact, particularly in the gamma-ray well logs.

Test Methods

The first injection was made through a slot cut in the casing at a depth of 290 ft and consisted of 27,000 gal of a mixture of water, cement, and diatomaceous earth, tagged with

35 curies of ^{137}Cs. The cement and diatomaceous earth were brought in dry in transit-mix concrete delivery trucks and were mixed and pumped into the well by the Dowell division of the Dow Chemical Company, one of the major oil-field service companies, using standard truck-mounted oil-well fracturing equipment. The cesium tracer was added at the wellhead by a small high-pressure metering pump (Fig. 3.1).

The day before the injection, the fracture was initiated with water. The pressure was built up slowly to 2300 psi, at which point the shale parted and the pressure fell abruptly to 1000 psi, and in 15 min to 700 psi, while the pumping rate increased from 0 to 300 gpm. A total of 1400 gal was pumped into the well at this time. On shutting down the pumps, the wellhead pressure dropped abruptly to 300 psi, so that the static pressure in the fracture must have been 425 psi [300 psi + (290 ft × 0.433 psi/ft)]. The pressure due to weight of the rock at a depth of 290 ft would be about 300 psi if the rock had a specific gravity of 2.45. The specific gravity of the unweathered shale, below a depth of 100 ft or so, is probably near 2.65; but in any case the fluid pressure which formed the fracture was appreciably greater than the weight of the overburden.

Results

Twenty-two core holes were subsequently drilled in the area, and from the cores, from gamma-ray logs of the core holes, and from surface geologic mapping, the cross sections and

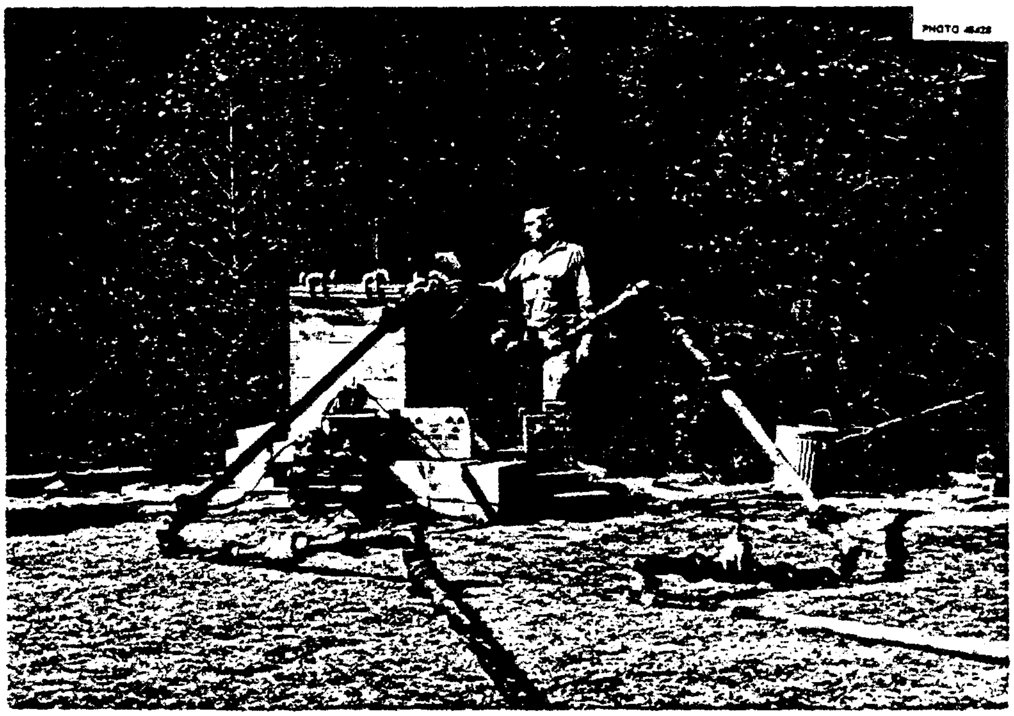

Fig. 3.1. High-Pressure Lines from Pump Trucks, Wellhead, Shielded Tank for Tracer, and Small Tracer Injection Pump. First fracturing experiment.

map shown in Figs. 3.2 to 3.4 were prepared. These show that the grout-filled fracture followed the bedding closely, moving in general north up dip and to the east and northeast. To the west the movement was apparently blocked by sharp folding and a hard sandy lens in the shale. The

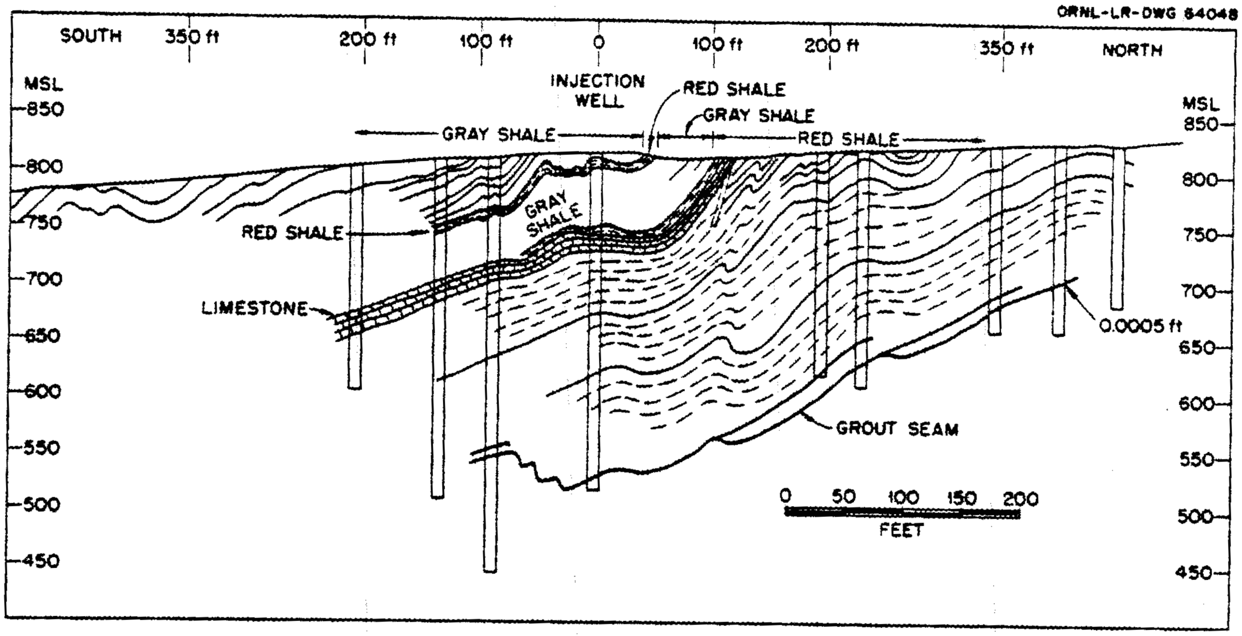

Fig. 3.2. First Hydraulic Fracturing Experiment, 4-acre Site, Oak Ridge.

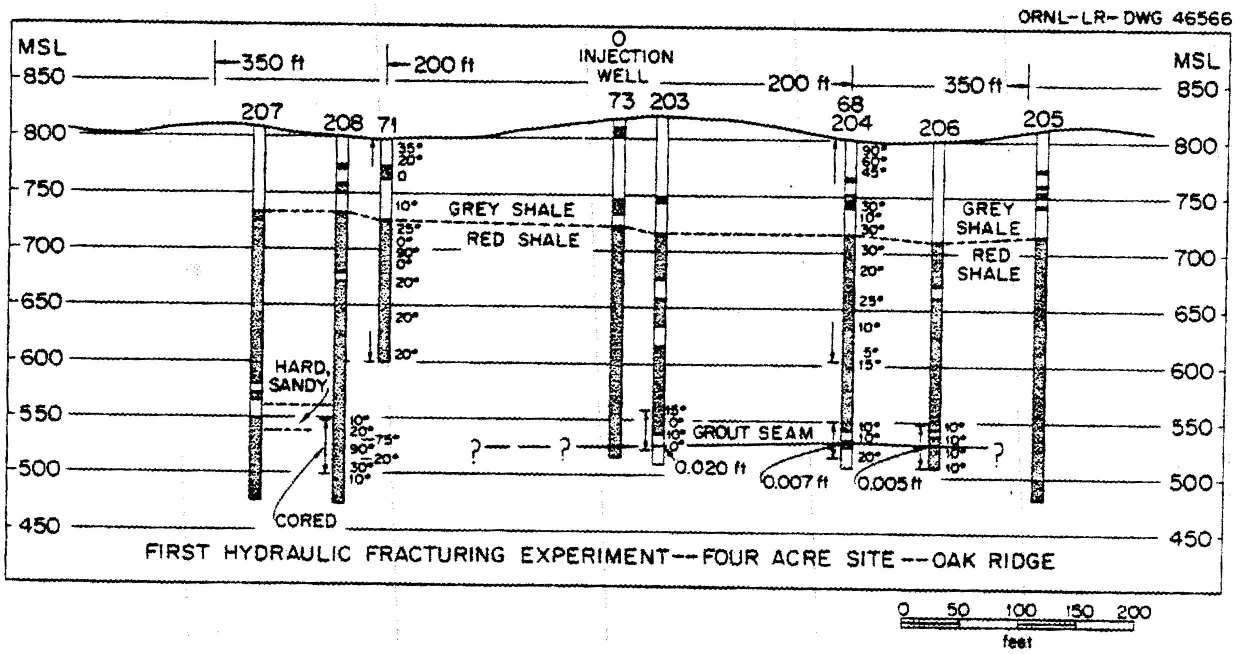

Fig. 3.3. First Hydraulic Fracturing Experiment, 4-acre Site, Oak Ridge.

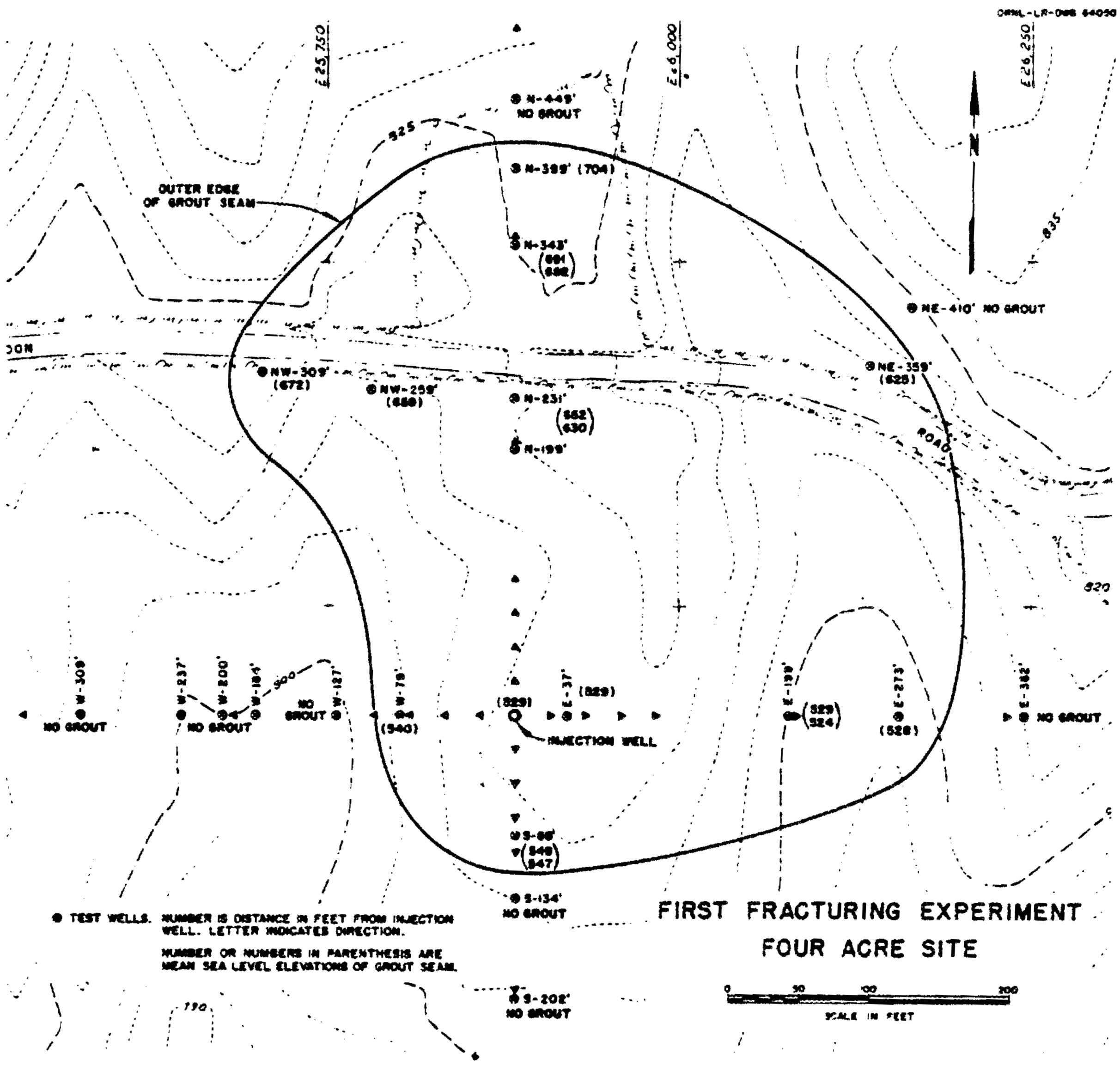

Fig. 3.4. First Fracturing Experiment, 4-acre Site, Oak Ridge.

smaller drag folds and the few minor faults appear to have had but little influence on the fracture, although two larger overturned drag folds appear to have caused the sheet to divide into two. Down dip the sheet appears to have broken upward a short distance across the bedding.

The elevations of a network of bench marks in the area were determined before and after the injection. High-precision equipment was not available, and the results were only sufficient to suggest that the rock over the grout sheet had been uplifted by about the thickness of the grout, which in the recovered cores ranged from about $\frac{1}{4}$ in. (0.02 ft) near the injection well to paper thin about 400 ft to the north.

The most important result of this first experiment was proof that the method could be used to determine the precise underground location of the tagged grout sheets. In work with the cores a G-M survey meter makes it possible quickly to locate thin seams of grout which might otherwise have been overlooked, and gamma-ray logging of the wells, in this and in all subsequent work, has in every case been able to pinpoint the location of the fracture in each test hole or to show that the hole had not intersected it. The formation of a bedding plane fracture at so shallow a depth was not in itself a matter of much importance, although the result was encouraging.

SECOND FRACTURING EXPERIMENT (SEPTEMBER 1960)

The second fracturing experiment was carried out about 6000 ft east of the first. Work began with the drilling of a 3-in. core hole, which encountered the Rutledge–Pumpkin Valley contact at about 650 ft and the top of the Rome formation at about 1000 ft. The injection well was located 30 ft east of the core hole. The first injection was made into a slot at a depth of 934 ft and consisted of 91,500 gal of water, cement, and bentonite clay tagged with 25 curies of ^{137}Cs. Pressure readings were taken at the wellhead of the injection well and also at the top of the core hole, which had been converted into an observation well by casing it down to a depth of 890 ft, below which it was open hole. At a depth of 934 ft the pressure due to a rock overburden with a specific gravity of 2.65 would be 1076 psi; the pressure observed at the surface in a static observation well filled with water would be 673 psi.

Test Method

The fracture was initiated with water. The well broke down at 1500 psi surface pressure, but this pressure fell quickly to 1350 psi at a pumping rate of 140 gpm and then increased to a maximum of 1640 psi as the pumping rate was increased slightly (Fig. 3.5). After 6 min, by which time 850 to 900 gal of water had been pumped, the fracture broke into the nearby core

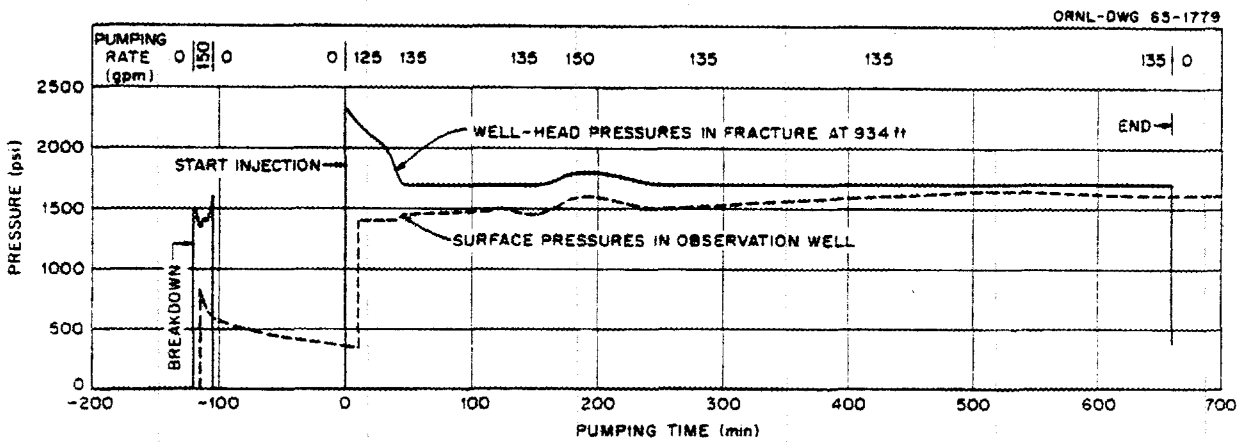

Fig. 3.5. Second Fracturing Experiment, First Injection, Sept. 3, 1960.

hole, where the pressure at the wellhead suddenly went to 800 psi. The 600 psi difference between the pressures in the injection well and the observation well was due to friction loss, largely in the fracture, which presumably was very narrow, as it had just been formed. The distance in depth between the two wells is uncertain but is probably of the order of 20 to 40 ft.

The water was bled back out of the injection well, and the pressure in the observation well fell to 350 psi in about 100 min. The main injection of the water-cement-bentonite mixture, which had a nominal density of about 12.5 lb/gal, was then started. The initial pressure required to inject the grout was about 2300 psi, but this dropped somewhat erratically over a period of about 40 min to a pressure of 1700 to 1750 psi, which was maintained throughout the remainder of the injection, except for a brief period when the injection rate was increased from 135 gpm to 150 gpm and the pressure rose to 1800 or 1850 psi.

The grout broke into the observation well about 9 min after the injection had started, and the pressure gage on this well jumped suddenly to 1400 psi. In general this pressure, which is of course a measure of the true pressure in the fracture, rose slowly but steadily during the injection and reached a value of about 1700 psi at the end. The difference between the wellhead pressures in the two wells was therefore about 900 psi at the start of the injection, about 200 psi after 1 hr, and only 50 to 100 psi after 11 hr. Because the grout had a nominal density of about 12.5 lb/gal, the readings in the injection well should be increased by about 600 psi to give bottom-hole pressure, and the readings in the water-filled observation well should be increased by about 400 psi to give the pressure in the fracture. After these corrections, the friction loss when pumping the grout, which had an apparent viscosity of about 15 poises, varied from about 1100 psi at the start to 400 psi after 1 hr of operation and was about 250 to 300 psi at the end. These are maximum differences, for there is some reason to believe that the density of the grout was a little less than 12.5 lb/gal. These readings are the only ones made in which it is possible to compare the wellhead pressure in the injection well with the actual pressure in the fracture.

Examination of the cores strongly suggests that the shale has negligible tensile strength normal to the bedding, so that the 1500-psi breakdown pressure required to initiate the fracture represents the pressure required to force open the sides of the fracture sufficiently to permit the flow, not the force required to break the rock in the usual sense. This would explain the appreciably higher pressure required to pump in the more viscous grout, even though the pumping rate was the same as with the water, for the fracture would have had to be forced wider open.

The rapid, somewhat irregular drop in the wellhead pressure of the injection well during the first 40 min, accompanied by a slight rise in pressure in the fracture at a distance estimated to be between 20 and 40 ft out from the injection well, shows that this pressure drop is due to friction in the fracture near the injection well and that the decrease in the injection pressure is almost certainly due to an increase in the width of the fracture during this period, not to a drop in pressure in the fracture itself. Pressure measurements made at the wellhead of the injection well during all subsequent injections also showed a decline in pressure as the injection progressed. Presumably, these also were due to a progressive widening of the fracture, although other explanations are possible. Unfortunately, partially cased observation wells to measure the pressure in the fracture are awkward to construct, and no more were used; however, in retrospect the data they provide appear to be particularly enlightening.

At the close of the first injection of the second experiment, the injection well was plugged with neat cement grout back up to a depth of 700 ft below land surface. Six days later a second slot was cut in the injection-well casing at a depth of 694 ft, and the well was broken down with water at a pressure of 1800 psi, which increased to 2500 psi at a pumping rate of 275 gpm. After 20 min of pumping at this rate, the pressure had fallen to 2000 psi; when the pumps were stopped the static pressure noted was 1500 psi. This water, 6300 gal, was not backflowed.

The next day (Fig. 3.6) the well was again broken down with 4000 gal of water at a pumping rate of 250 gpm and a pressure of 1800 to 2000 psi. Twenty minutes later the main grout injection was started at a rate of 230 gpm and a pressure of 2200 psi. Small pieces of hard rock in the cement interfered with the operation of pumps, so that the time-pressure curve is complex. The pressure fell from 2200 to 2000 psi during the first 80 min and then held constant until, after 200 min, the pumps had to be shut down for 20 min. When the injection was resumed, the pressure required was once more about 2200 psi, which after about 100 min dropped again to 2000 psi. After about 460 min the trouble with the pumps, which had caused brief variations in pumping rate and pressure not shown in Fig. 3.6, had been corrected, and the pumping rate was increased to 290 gpm. This resulted in a third rise in pressure, to about 2300 psi, which dropped after 40 min to 2200 psi. This pressure was maintained until the end of the injection.

Results

About 24 core holes were subsequently drilled in the area, and the extent, depth, and thickness of the two grout sheets as well as the locations of the upper and lower contacts of the Pumpkin Valley shale were more or less well defined. Maps and sections, corrected for the deviation of these core holes from the vertical, showed that these fractures also had been closely guided by

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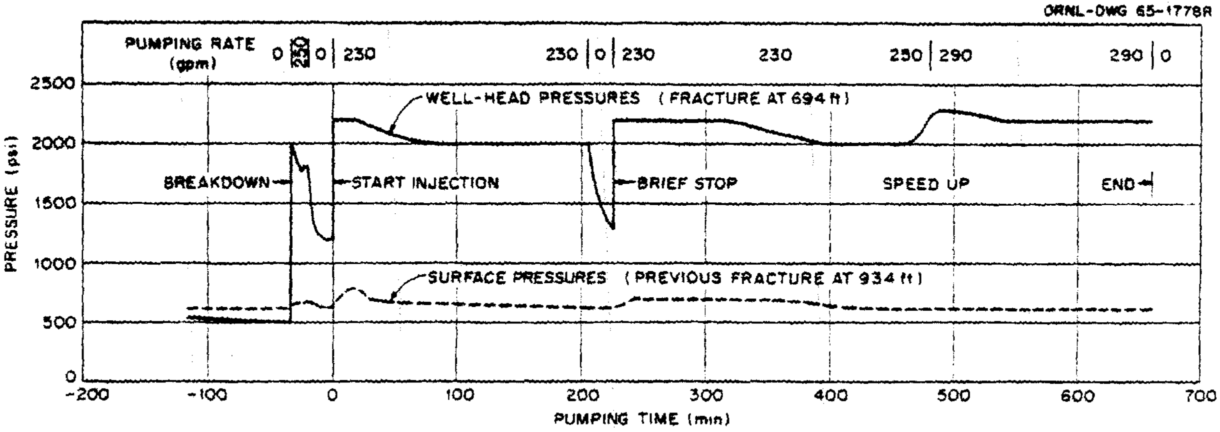

Fig. 3.6. Second Fracturing Experiment, Second Injection, Sept. 10, 1960.

the bedding, although each had tended to work its way upward stratigraphically as it moved out (Figs. 3.7 to 3.10). For example, the upper sheet, which was injected at a point about 50 ft lower stratigraphically than the three limestone beds, was found closer and closer to the beds to the east of the injection well and intersected them about 500 ft to the east. This upward displacement is believed to have taken place where the fractures broke across the crests of small drag folds in the shale, although there is no direct evidence for this.

Surface Uplift

A network of 33 bench marks was installed in the area, radiating out in six lines from the injection well to distances of from 400 to 1200 ft; the longest line was to the north and the

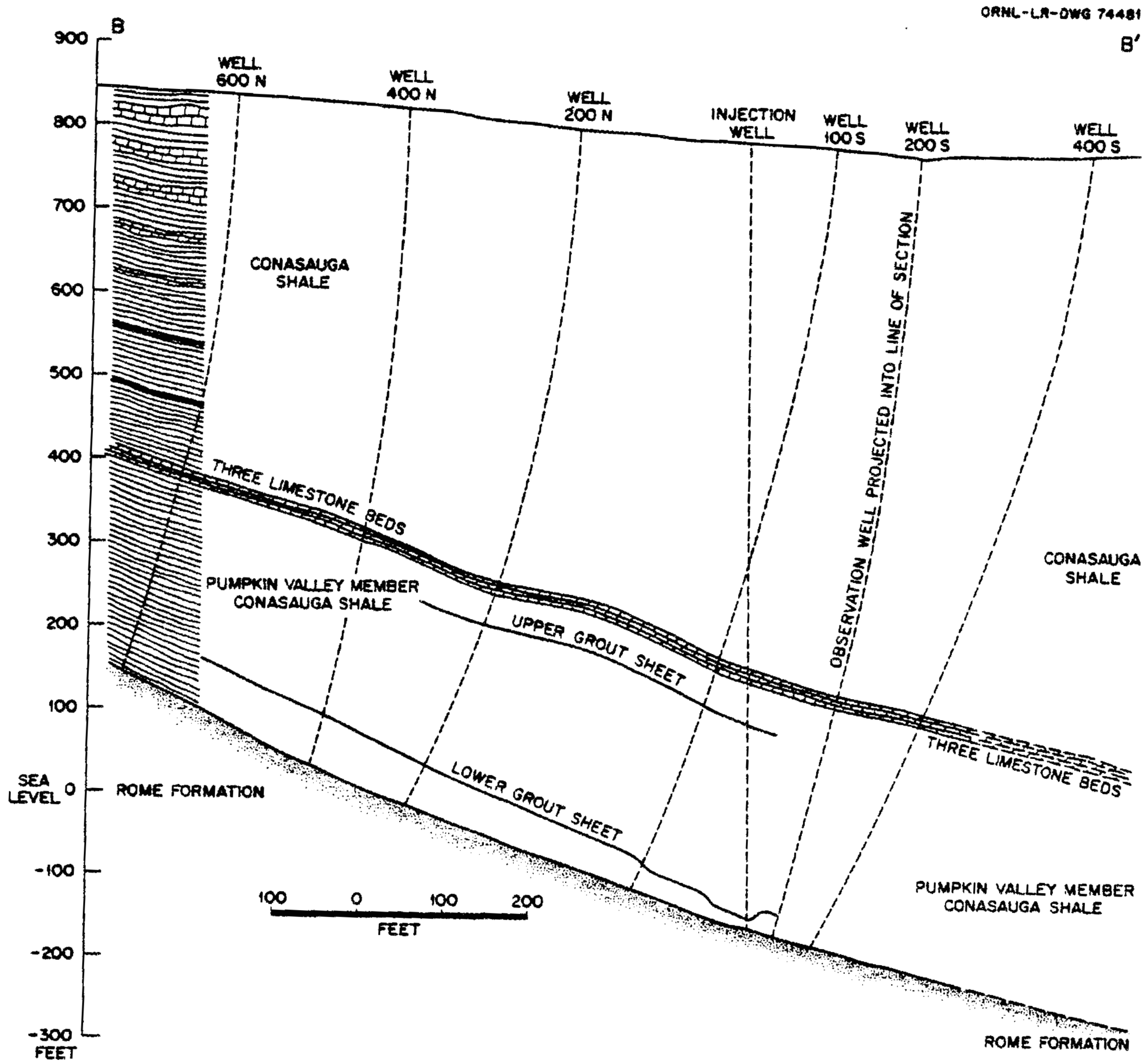

Fig. 3.7. Second Fracturing Experiment.

shortest to the south. Relative elevations were established to within the nearest thousandth of a foot prior to the first injection and subsequent to each of the two injections. These elevations were determined by the U.S. Geological Survey. Figure 3.9 shows the surface uplift resulting from the injection of the lower grout sheet, which had moved up dip from the injection well in a long narrow sheet. Unquestionably, the surface uplift was much more extensive than the grout sheet.

The surface uplift appears to be centered south of the center of the grout sheet. However, the grout sheet slopes to the south, and, as may be seen from Fig. 3.7, a line projected upward from the center of the grout sheet, normal to it, would intersect the land surface at about the center of the area of surface uplift.

Two complete cores and one partial core containing the grout sheet were recovered. Examination of these suggested that the amount of uplift at a point on the surface underlain by the grout sheet was about equal to the thickness of grout directly below it. This relation is believed to be coincidental.

The uplift produced by the second (upper) injection was also much more extensive than the grout sheet (Fig. 3.10) and also centered around the point where a line projected upward normal to the grout sheet at its center would intersect the land surface.

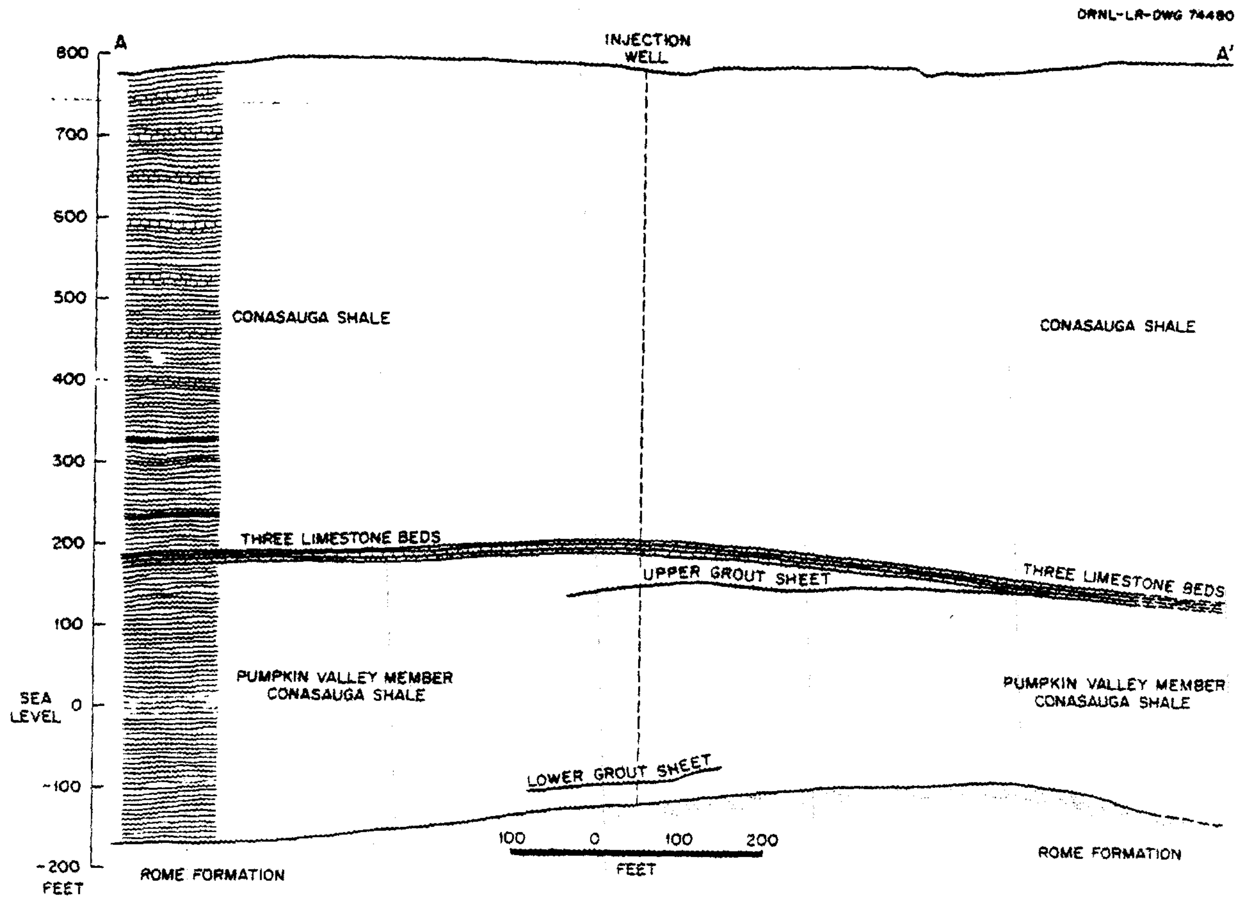

Fig. 3.8. Second Fracturing Experiment.

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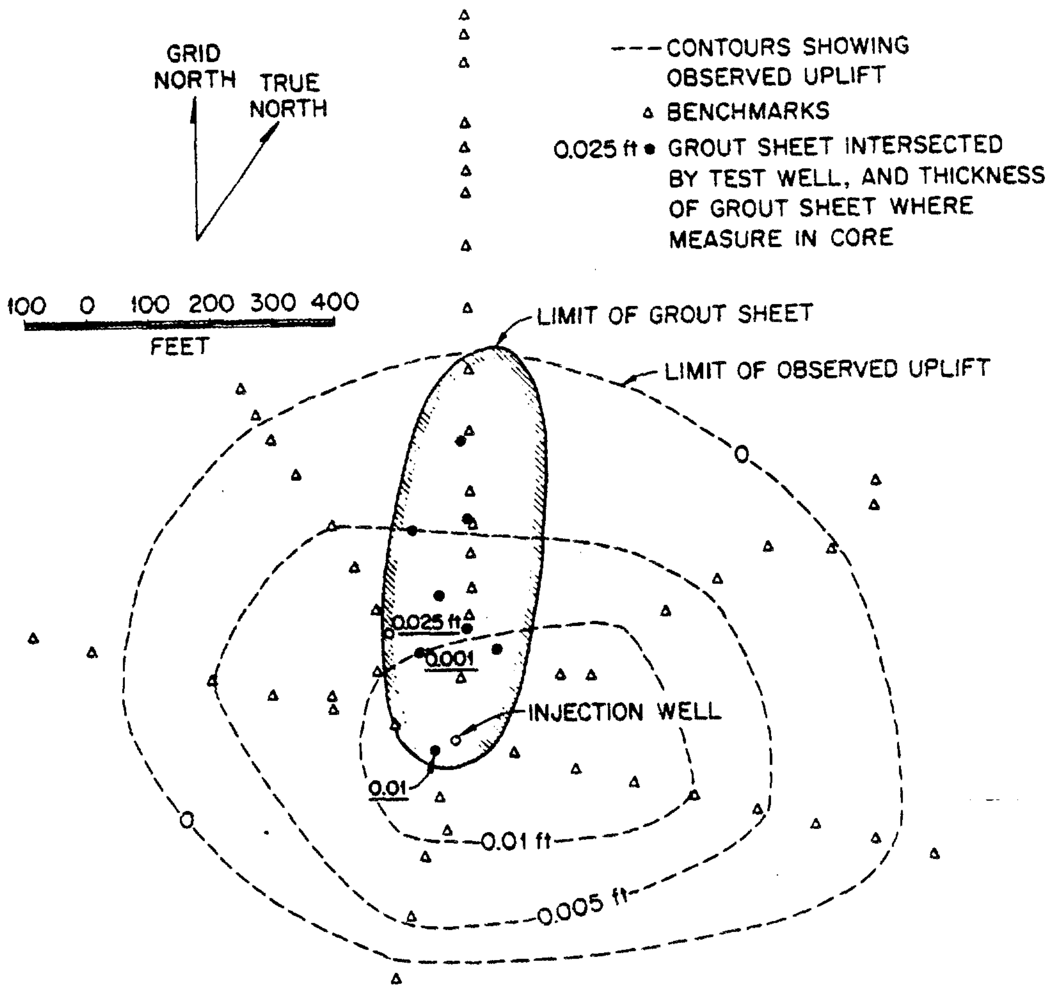

Fig. 3.9. Second Fracturing Experiment. Observed surface uplift due to injection of lower grout sheet compared to extent and thickness of grout sheet.

Six cores of this sheet were recovered in which the thickness of the grout could be measured, and these thicknesses agreed generally with the amount of surface uplift directly above.

The U.S. Geological Survey also made very precise measurements of the tilting of the land surface at two locations during the first injection and at three during the second.[8] The locations of the tiltmeters are shown in Fig. 3.10, and the observed tilting is shown in Figs. 3.12 and 3.13.

Just prior to the first injection, the 200-ft interval spanned by the west tiltmeter slowly tilted away from the injection well, probably as the result of earth tides. This movement was

[8]F. S. Riley, "Tiltmeter Measurements During Hydraulic Fracturing Experiments at Oak Ridge, Tennessee," U.S. Geol. Surv., Profess. Paper 424-B, p. 317, 1961.

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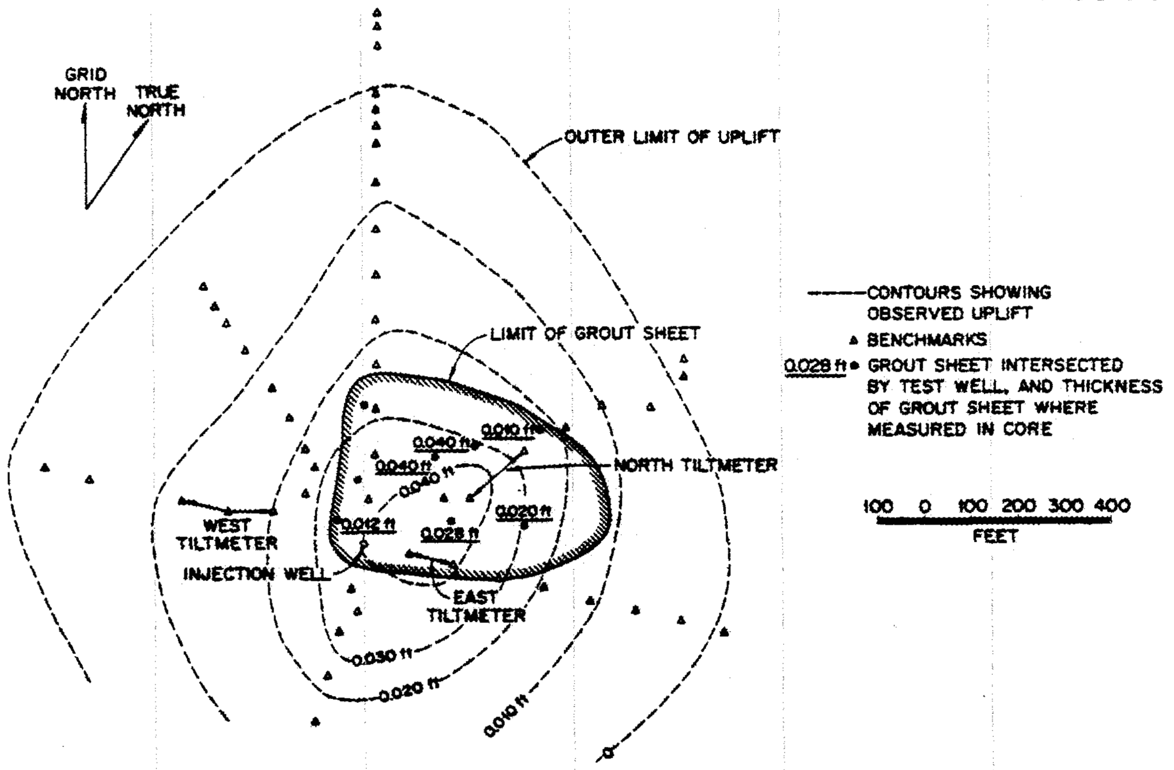

Fig. 3.10. Second Fracturing Experiment. Observed surface uplift due to injection of upper grout sheet compared with extent and thickness of grout sheet.

not affected by the breakdown with water at −100 min and only increased in rate about 100 min after the main grout injection had started.

The 100-ft interval spanned by the east tiltmeter tilted slowly toward the injection well at the start of its period of record. This movement reversed about 40 min after the injection started, but marked tilting away from the well only began about 100 min after.

These data suggest that during the first 100 min of the first injection, the space for the fracture was created by compressing the immediately adjacent rock but that later, after the fracture was more extensive, the space was provided by uplifting the rock cover.

Tiltmeter data for the second (upper) injection show a somewhat different pattern. The intervals spanned by all three tiltmeters began to tilt away from the injection well as soon as the injection started (Fig. 3.13) and, indeed, may have started to tilt away when 4000 gal of water was pumped into the fracture 20 min prior to the start of the grout injection. Conditions on this occasion, however, differed importantly from those of the preceding injection. This time the well had been broken down the day before (September 9) with 16,000 gal of water which had not been bled off. On September 10, prior to any pumping, the wellhead pressure on the injection well was about 500 psi, or almost exactly the pressure due to the weight of the

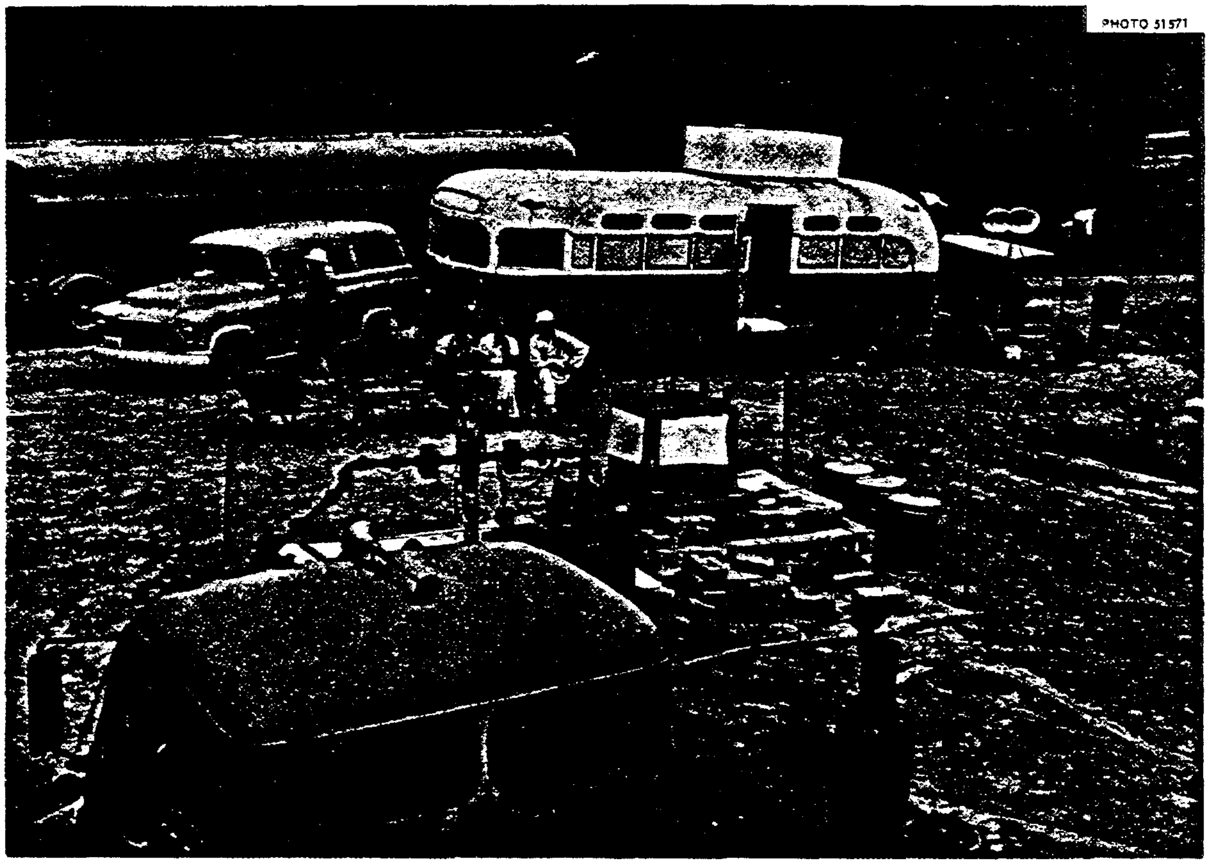

Fig. 3.11. Second Fracturing Experiment. At center, wellhead with two pipelines connected to pump trucks, and shielded container for tracer. In background, 20-ton bulk cement truck.

rock cover. Therefore, when the injection started on September 10, there was already a fracture, probably not very wide but fairly extensive, filled with water at very nearly the overburden pressure. More importantly, when the first (lower) injection was made, the overlying shale was in a "relaxed" condition, and the fracture apparently formed by first compressing and then later by uplifting the overlying rock cover. However, when the second (upper) injection was made a week later, the rock cover was still under stress, that is, still compressed; and rather than compress further, the space for the second fracture was made, even initially, by uplift of the cover rock.

The widespread surface uplift extending well out beyond the outer limits of the grout sheet can be explained, qualitatively at least, on the basis of the shearing strength of the shale. This has not been measured, but the rock is well indurated and has a crushing strength normal to the bedding of 7780 psi, parallel to the bedding of 4870 psi, and at 45° to the bedding of 3810 psi, as measured in the laboratory on small samples. The shale has virtually no tensile strength normal to the bedding.

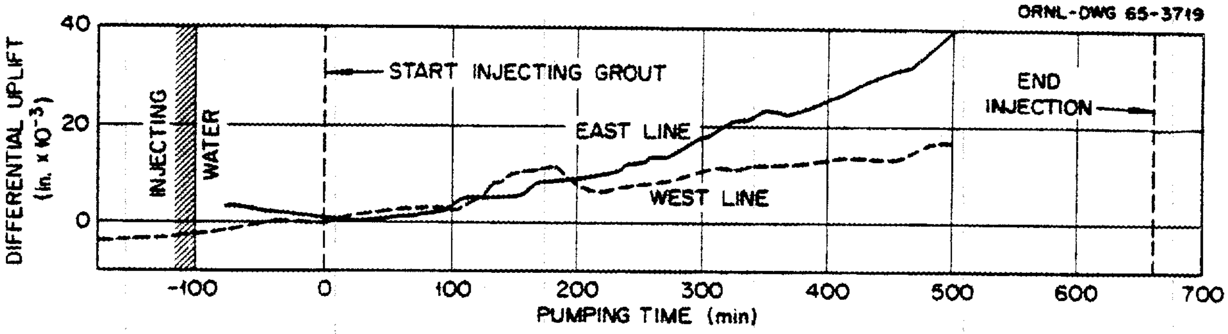

Fig. 3.12. Uplift of Closer Piers Relative to More Distant Piers, Sept. 3, 1960. Tiltmeter measurements, second fracturing experiment, lower injection. Data from USGS.

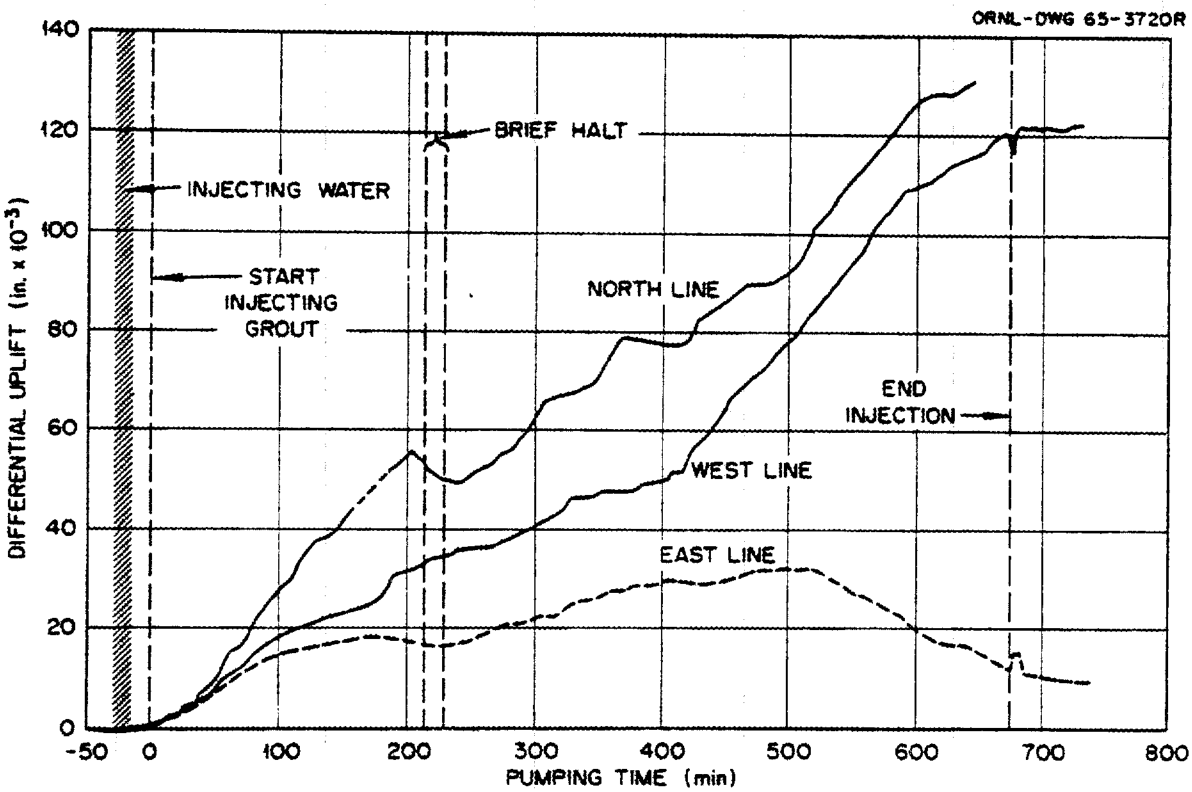

Fig. 3.13. Uplift of Closer Piers Relative to More Distant Piers, Sept. 10, 1960. Tiltmeter measurements, second fracturing experiment, upper injection. Data from USGS.

Measurements made in the observation well during the first (lower) injection of the second experiment showed that the pressure in the fracture was substantially greater than the pre-existing vertical pressure, which may be taken as the weight of the overburden. Because the shale is not rigid, it must have been somewhat compressed by this increase in pressure, and apparently in the initial stages the opening formed by the partings of the shale must have been provided by this compression. The high pressure drop in the vicinity of the injection well, as shown by the big difference between the pressures in the injection and observation wells, shows that in this early stage the fracture was narrow. The pressure difference, however, decreased rapidly at first and then more slowly as the injection pressure dropped, indicating that the fracture got increasingly wider as the injection proceeded. However, in all three injections, the pressure required to propagate the fracture was always substantially higher than the pressure due to the weight of the overburden. Reference to Fig. 3.14 will illustrate qualitatively why this is so. At the stage illustrated the grout-filled fracture has moved out far enough from the injection well so that substantial surface uplift has resulted. The rock mass shown in section may be divided into three zones. The first, directly over the grout sheet, is subjected to a vertical force upward, and the rock is compressed by this force. Around this zone is a ring-shaped zone, triangular in cross section, in which the rock is subjected to a shearing force as the result of the upward movement of the adjacent rock mass, the mass directly over the grout sheet. The shearing force within this rock mass acts, in a sense, like a tensional force,

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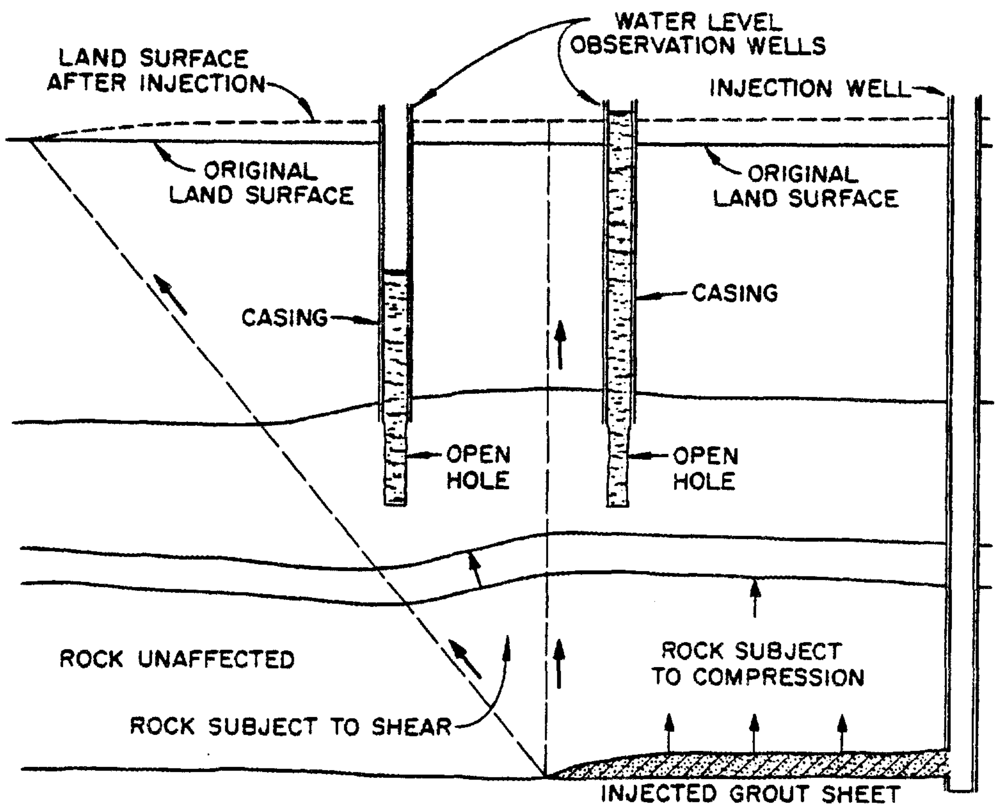

Fig. 3.14. Stresses in Rock Due to Injected Grout.

in that it reduces the compressional force due to the weight of the rock. As a result the rock expands, and the surface uplift in this zone is an expression of the increase in volume. In the third, outer, zone the rock is undisturbed by the injection. The boundaries between the zones are probably not sharp, nor are they necessarily straight lines when seen in section, as shown in Fig. 3.14, but the generalization is useful. For example, the fluid in the fracture has to lift up not only the directly overlying rock, zone 1, but also the rock in the ring-shaped surrounding zone, zone 2, which explains why the pressure in the fracture has to be so much greater than that required to move only the vertically overlying rock. In the injection at 934 ft, the weight of the overburden was about 1000 psi; the pressure in the fracture at the end of the injection was about 2100 psi. This might suggest that, as a first approximation, the volume being uplifted should have been twice the volume of rock directly over the grout sheet. However, the volume was much larger than this. But the uplift was not the result of bodily lifting all the rock against the force of gravity; the uplift in zone 2 was due to a partial relief of load due to the shearing force, so that the rock expanded. This expansion would be determined quantitatively by the modulus of elasticity of the shale and the distribution of forces within it, a very complex problem.

The volume of the surface uplift, which has roughly the shape of a thin slice taken from a very large sphere, must be approximately equal to the volume injected, minus the volume reduction of the rock compressed in zone 1, plus the volume increase of the rock in zone 2. In the first (lower) injection of the second experiment, the compression of the overlying rock must have been considerable if one accepts the evidence of the tiltmeters that no surface uplift was produced during the first 100 min of pumping. Indeed, if the experiment had stopped at this point, all of the volume injected would have been taken up by rock compression. As it was, the total volume injected was 12,300 ft^3, and the volume of the "dimple" formed by the surface uplift was about 5020 ft^3. Apparently the rock compression in zone 1 was greater than the rock expansion in zone 2.

The second (upper) injection of the second experiment was not entirely independent of the first, in that some of the rock was already compressed up to the limit where surface uplift commences, as was shown by the tiltmeters, which indicated further surface uplift starting immediately after the injection started. The volume of the second injection was 17,700 ft^3; the volume of the additional surface uplift caused by this injection was about 22,800 ft^3. Apparently, in this case, the volume increase in zone 2 was greater than the volume reduction in zone 1.

The observation that the thickness of the grout sheet in the cores is in general equal to the overlying surface uplift is incompatible with the preceding discussion. Directly over the grout sheet the rock cover is compressed, and the surface uplift must be less than the thickness of the grout. The mixes used in the two injections of the second experiment were not designed, however, to retain all the water; in fact, later work shows that the solids would settle in such a mix, leaving clear water on top after the cement had hardened. The first core hole, but only the first, drilled into the upper grout sheet six to eight weeks after the injection, flowed slowly for a long time. The density of samples of the grout recovered and the total weight of solids injected suggest that the first injection formed 2700 ft^3 of solid grout, leaving 9600 ft^3 of excess water, and the second injection formed 9000 ft^3 of solid grout, leaving 8700 ft^3 of excess water. Much of this excess water still must have been in the fractures when the leveling was done, but later it must have squeezed out slowly into the wall rock and/or migrated elsewhere. Certainly it was not included in the measured thickness of the solid grout. So the width of the fracture at the time of the leveling was greater than the observed uplift, and the apparent relation noted was fortuitous.

Several factors suggest that following the injections there should have been a slow subsidence of the surface area uplifted. The free water would have slowly migrated into the wall rock, despite its low porosity and permeability, some laterally into zone 3, and some diagonally upward into zone 2. More important, the shale being slightly plastic, the area uplifted by the shearing forces in zone 2 would have settled as these forces were dissipated by flow in the rock; indeed this area might be expected eventually to return to its original position. Because the load bearing down on zone 1 is in part due to the transfer of load from zone 2, the slow dissipation of this stress by plastic flow would permit the rock in zone 1 to expand. This would counter the postulated subsidence of the surface uplift over zone 1, which was based on a speculative conclusion that the excess water was squeezed out of the fractures.

A resurvey of the experimental area in 1964 by members of the Laboratory engineering staff, who by now had acquired high-precision equipment, showed to our surprise that the whole area had returned to essentially its original position (Fig. 3.15). A few of the bench marks did not, but the general pattern is unmistakable. In default of any "reasonable" explanation, the author's present opinion is that this return to the preinjection elevation of the land surface, over both zone 1 and zone 2, results from some fortuitous balancing of factors and is not necessarily the result that should be expected.

The design, location, and use of monitoring and observation wells is to ensure that no underground failure has taken place. An underground failure might mean that the waste injections had formed vertical rather than horizontal fractures, or it might mean a faulting or other failure of the cover rock which would permit the movement of groundwater or waste through rock which had previously been essentially impermeable.

Proof that several bedding-plane fractures were formed is no assurance that they will continue to form with continued injection of batch after batch of waste into closely spaced slots in the injection well. There is some reason to believe that the shale is sufficiently plastic that over a period of several years the bulk of the stresses produced by an injection will have been dissipated, but there is no proof of this. There could conceivably be, with repeated injections, a continuing buildup of vertical stress in the cover rock over the grout sheets, that is, in zone 1. This, if it occurs, would promote the formation of vertical fractures, which become more probable where the vertical stress exceeds the least horizontal stress.

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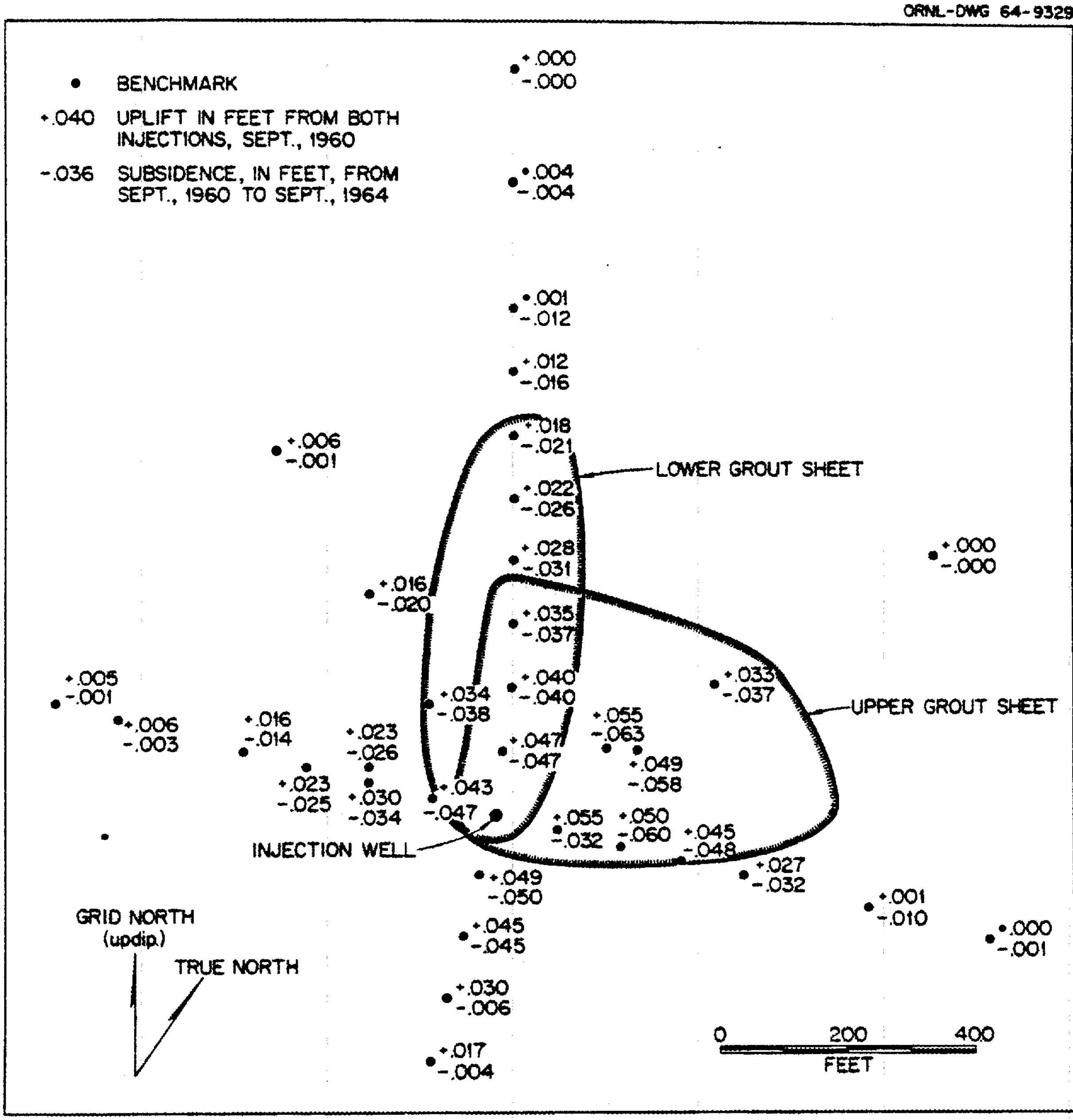

Fig. 3.15. Surface Uplift and Subsidence Second Fracturing Experiment.

On the other hand, in zone 2, any unrelieved shearing stress would tend to reduce the overburden pressure, so that any grout sheet breaking out into an area not underlain by earlier grout sheets would find its further extension along the bedding plane facilitated by a reduction in the vertical stress.

With these ideas in mind, a single prototype well for monitoring by gamma-ray logging (Fig. 3.16) was installed 150 ft north of the injection well at the plant site. The injection well

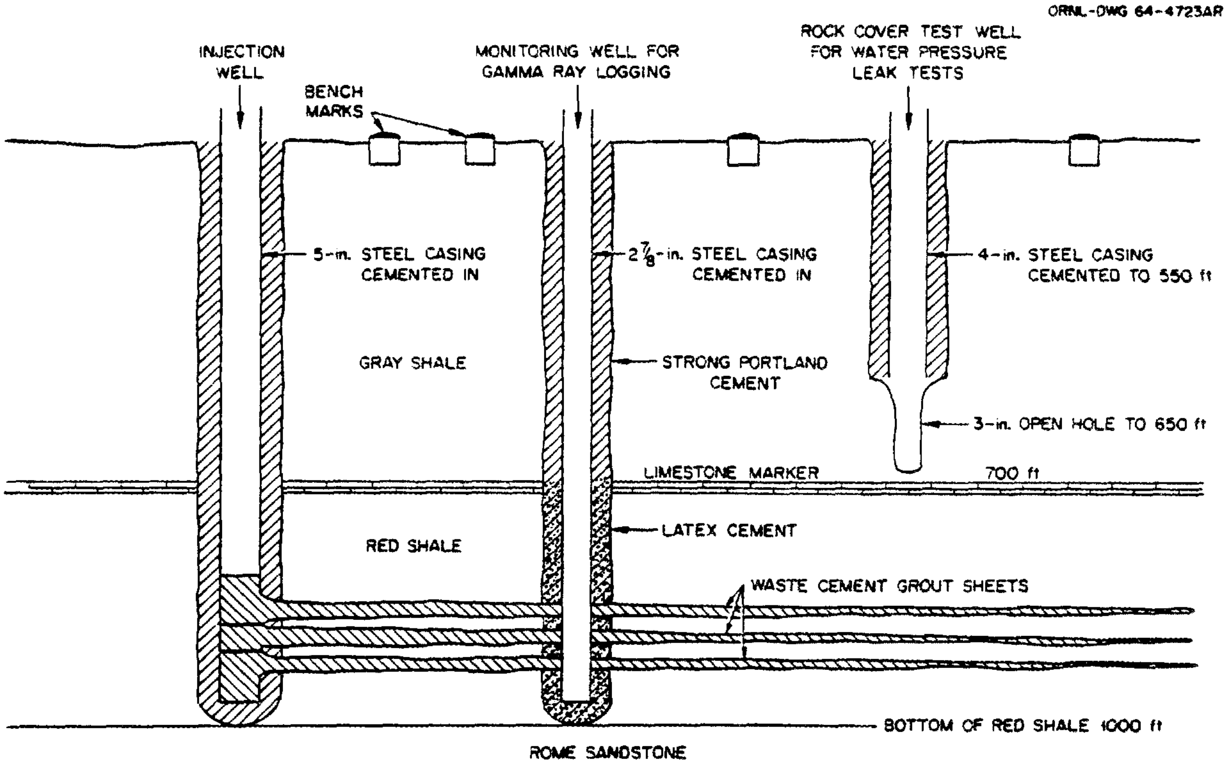

Fig. 3.16. Well Layout.

itself, 1050 ft deep, penetrated the same formations at almost exactly the same depths as the injection well used for the second experiment. The monitoring well was constructed much like the disposal well in that it was cased all the way through the Conasauga to the top of the Rome. The inner diameter of the casing, however, was $2\frac{7}{8}$ in., one of the smaller sizes in which it is possible to get high-strength oil-field tubing. The idea was that following each injection a gamma-ray log would be made by lowering the probe down the well, and a new peak would be recorded where the fracture from the most recent injection intersected the well; or no new peak would be recorded if the fracture had not intersected the well. Use of a net of such monitoring wells around the injection well would permit a rapid determination of where each grout sheet had gone very soon after it had been injected, without the expense of drilling and plugging a number of test holes.

The bottom 300 ft of the prototype monitoring well was cemented in with a plastic latex-base cement because, where each fracture intersects the well, the overlying rock and the casing cemented into it will be raised about $\frac{1}{2}$ in. while the lower section, below the fracture, will remain fixed. The latex cement was intended to provide for some differential movement between the wall rock and the casing, so that the casing would not be ruptured where the grout sheet intersected it. The latex cement proved, however, to be either too weak or not sufficiently plastic, because the three batches of radioactive material that reached the well migrated 50 to 100 ft up along the cement-filled annular space between the casing and the wall rock. Consequently, although the intersections of the grout sheets with the well could be located with reasonable confidence, there is now so much radioactive material behind the casing that the exact location of the next grout sheet may be hard to determine. New wells with a stronger cement are being installed, and it is hoped that these will work better. (Two of these wells have since failed, apparently by being pulled apart where intersected by injection ILW-2 in April 1967. The two wells are still usable, but the water in them is slightly contaminated.) The basic concept appears sound; the problem is to design and construct wells with a cement bond sufficiently plastic so that the casing will not be ruptured even by several feet of surface uplift, but strong enough to prevent any movement of radioactive material between the casing and the wall rock. Such monitoring wells will greatly reduce the need for expensive core drilling, but some core drilling will occasionally be required to determine the exact location and condition of the grout-filled fractures. After completion, these core holes can be converted into cased monitoring wells, to replace older wells or to extend the network.

The safety of the disposal operation depends not only on successive grout sheets moving out horizontally and not breaking up vertically toward the surface, but also on the continued impermeability of the cover rock. The effectiveness of the original rock cover as a seal was shown (1) by examination of the rock cores, which showed no solution cavities, iron stains, or signs of weathering below a depth of about 200 ft; (2) by laboratory tests on samples from the cores, which showed permeabilities parallel to the bedding of the order of 10^{-4} millidarcy; (3) by the very slow drop in pressure in grout- or water-filled fractures after pumping had stopped; (4) by the presence of sodium chloride and gas under low pressure in the Pumpkin Valley shale; and (5) by the geothermal gradient, which, when compared with the thermal conductivity of samples of the shale, strongly suggested that there is no quantitatively significant movement of groundwater deeper than 400 ft below the surface and probably little deeper than 200 ft.

The gas in the Pumpkin Valley shale, which was encountered in small quantities in several of the test wells, was 85 to 95% nitrogen, 1% oxygen, and the rest methane or related hydrocarbons. The nitrogen is presumably air which has lost its oxygen to iron or some other partially oxidized material in the shale, and the methane was formed from plant remains trapped in the shale. They, like the sodium chloride, are presumably connate, to use the term in its broad sense, but whatever their origin their presence shows that the rock cover is virtually impermeable.

When the disposal plant is in operation it is planned to inject about 200,000 gal of grout into a fracture, with the fractures spaced 5 to 10 ft apart over the 300-ft thickness of the Pumpkin Valley shale. A single injection of 200,000 gal forms a grout layer $\frac{1}{2}$ in. thick; three such injections into the same fracture would form a layer near the well about 1.5 in. thick. If as many as 60 such fractures were formed, the increased thickness of the Pumpkin Valley would be 90 in., or about 8 ft. It was thought that the hazard, if any, would come from the stretching of the rock cover as it was pushed from a flat surface into a curved one, but the difference in length of the chord and the arc with such widespread uplift would be so small, roughly one part in a million for the most extreme case, that this does not now seem to be the problem. The danger area would appear to lie either along the contact between zone 1 and zone 2, where the shearing stress would probably be greatest, or along some sloping plane in zone 2 along which the shearing strength of the rock might more easily be exceeded than it would be in a direction normal to the bedding. In any case, the development of a thrust fault within zone 2 would show up as an anomaly in the uplift pattern as determined from the measurement of the bench marks, or it might show up as an increase in the permeability of the cover rock parallel to the bedding. The shale has little shearing strength in this direction, and any readjustment of the rock cover might well result in differential movement between adjacent beds. A single prototype "rock cover test well" was installed 200 ft north of the disposal plant injection well. This well was cased down to a depth of 550 ft and then was open hole to a depth of 650 ft, that is, to a depth roughly 50 ft above the highest level at which any waste injection is to be made. Prior to any of the waste injections, an attempt was made to pump water into this well at a surface pressure of 75 psi, but it would not take enough water to measure.

The attempt was made again shortly after several of the test injections. At first the well took water at a rate of nearly 5 gal/hr, which decreased slowly over a 4-hr period to a little less than 1 gal/hr. Observation in the gamma-ray monitoring well suggests that the fifth test injection did not pass under it or the rock cover observation well, so that following the injection the shale around the wells should have been subject to a shearing stress, and the consequent slight opening of a few bedding planes could easily have accounted for the rate at which the well took water. Presumably this acceptance rate will decrease as the stress is relieved in the slightly plastic shale and the rock cover returns to its original condition.

The value of such wells for their primary intended purpose, to give warning of impending failure of the rock cover, will depend on a much clearer understanding of how and where such a failure might take place. Only in this way can the observation wells be correctly located and the data obtained from them properly interpreted. On the other hand, our understanding of stress distribution in the rock cover and of the response of the cover to this stress is a complex problem about which probably only hints can be obtained by attempted theoretical analyses or model studies. The rock cover observation wells may, therefore, at first be of more value for the information they can provide about the effects of stress on the cover rock than as strictly monitoring devices.

All but the first of the five test injections made with the disposal plant in the spring and summer of 1964 contained some radioactive material. Gamma-ray logging of the cased monitoring well showed that injections 2 and 4 intersected the monitoring well and presumably passed under the rock cover test well just north of it. Injections 3 and 5 did not intersect the monitoring well and presumably did not pass under the test well. Figure 3.17 shows the water level changes in the rock cover test well. In the case of the fractures which passed under the well (2 and 4) the water level started to rise during the injection. In the case of the fourth injection, the well overflowed slowly for several days. If the casing had stood a few feet

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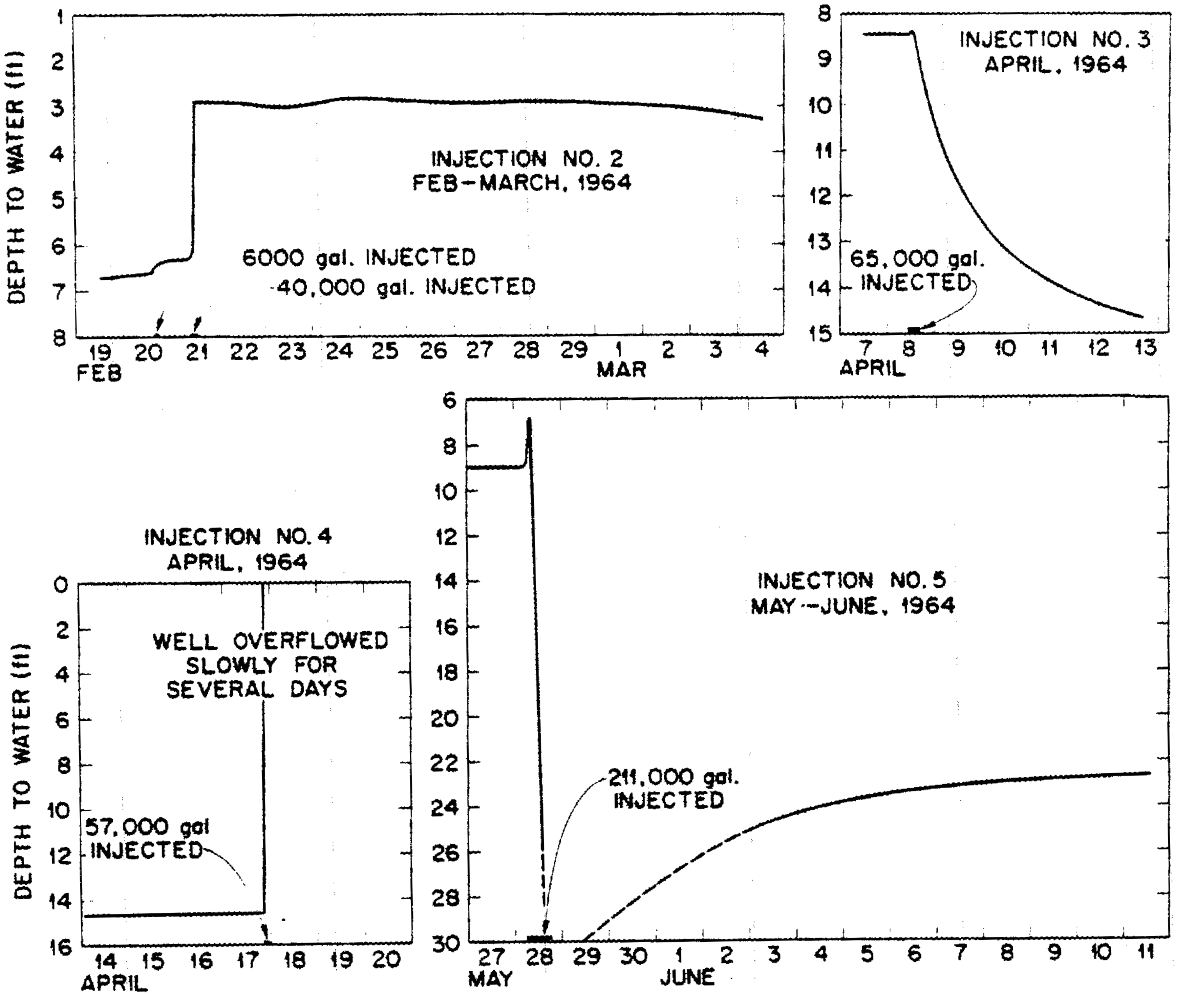

Fig. 3.17. Water Level Variations in Well N200 Resulting from Indicated Waste Injections.

higher, the water level would have maintained, for some time, the level it had reached when the injection ended, as it did in the case of the second test injection. With respect to these injections, the rock cover test well was in zone 1, where the rock over the grout-filled fracture is subjected to compression, and a few gallons of water was squeezed out of the shale into the lower uncased section of the well.

The third and fifth injections apparently did not pass under the rock cover test well. For about the first hour after the third injection had started, the water level in the test well rose slowly and then started to fall. In the case of the fifth injection, the initial rise was more marked, but it only lasted for 20 min before the water level started to fall. The initial rise is interpreted as representing the first phase of fracturing formation, where the space for the fracture is made by compressing the over- and underlying wall rock prior to any uplift of the rock cover. Local compression of the shale around the well would be immediately transmitted as a wave of compression for some distance out from the well, which would squeeze a small volume of water into the test well and raise its water level. However, when the cover rock started to move up, the test well was in zone 2, the zone of shear, and the laterally transmitted upward movement would have tended to reduce the load on the lower part, at least, of the cover rock, and the resulting expansion would have sucked a small volume of water into the shale. Later, the water levels slowly returned to their preinjection levels. The rock cover test wells therefore unexpectedly provided rather clear-cut evidence as to the stress exerted on the shale in their uncased section, and the observed results agree with our earlier expectation as to the nature of these stresses.

Conclusions

Fractures in the well-indurated shale of very low permeability at Oak Ridge appear to form at first by compressing the rock around the well. If so, the shape and depth of the slot cut to initiate the fracture may be material in ensuring that the fracture shall start out parallel to the bedding. Once the fracture has reached some critical size, the rock cover over the fracture is moved bodily upward, dragging with it, by virtue of the shearing strength of the shale, a surrounding ring-shaped volume of shale. Two zones may now be distinguished: that over the fracture, in which the rock is under compression, and an adjacent zone in which the rock is under shear.

With repeated injections and a surface uplift around the disposal well of several feet, the possibility that the cover rock may be faulted and consequently its value as a seal impaired can hardly be ignored. Also, with repeated injections, the state of stress in the shale around the disposal well may be so changed that vertical fractures will form. This appears unlikely, but two types of monitoring wells have been tested in prototype: one in which the location of the individual grout sheets can be plotted by gamma-ray logging and one which can be used to make regular checks on the permeability of the rock cover. Periodic measurements in these wells, exact determinations of surface uplift, and a close watch over the breakdown and injection pressures inquired should give adequate warning of any change in conditions which might adversely affect the continued safety of the operation. However, the more we learn about the complex rock mechanics of the operation, the more efficiently we can locate our monitoring and observation wells and make use of the data from them and other measurements of the movement of the rock cover.

4. Water Injection Tests

Water injection tests were first discussed at a meeting of the Advisory Committee on Waste Disposal on Land of the Earth Sciences Division of the NAS-NRC, held at Savannah River, Georgia, on December 7 and 8, 1961. The first report on the second fracturing experiment, presented to the committee at that time, showed that the fractures were conformable, and the discussion that followed centered around the committee's admonition that the ability to create conformable fractures should not be taken for granted in other areas. Indeed, it was the consensus that the subsurface formations at each site considered for disposal by hydraulic fracturing would have to be tested. This raised the question as to whether relatively inexpensive fracturing tests with water could be used, if not for final evaluation, at least to eliminate sites that would be definitely unsuitable. The conclusion was that if fracturing tests with water required pressures somewhat greater than the overburden pressure, horizontal fracturing could be presumed, though not proved; but, if fracturing pressures were less than the weight of the overburden, the fractures could not possibly be horizontal. Admittedly, there might be tests in which the pressure would be roughly equal to the weight of the overburden, in which case no conclusions would be possible. Our present opinion is but little changed, although as explained later, we now feel that the static shut-in pressure should be used rather than the dynamic pressure observed while pumping is in progress.

An additional incentive for making water injection tests at Oak Ridge resulted from development work on the waste-cement mixes suitable for use in the forthcoming injections of ORNL's intermediate level waste. The immediate point of interest was that fluid-loss additives were responsible for about half the cost of the ingredients in a mix which at that time appeared to come closest to meeting our requirements. However, there was no assurance that for our purposes low fluid loss was necessary or even desirable. The fluid-loss additives used in the petroleum industry and the laboratory methods employed to test the fluid loss of mixes are both designed for use in the fracturing of rocks, such as sandstones, which have permeabilities four or five orders of magnitude higher than the permeability of the Conasauga shale. These considerations raised the following questions: (1) Is there fluid loss when water is injected into the lower Conasauga shale by fracturing? (2) If so, where does the fluid go? (3) Can the fluid loss be reduced by the use of conventional fluid-loss additives? The purpose in making the water injection tests was to find answers to these questions and to record the results of a series of water injection tests in an environment that earlier work had shown would probably produce bedding-plane fractures.

WATER TEST PROCEDURES

Four water injections were made between June 4 and October 17, 1963. The first three, with clear water into a slot at a depth of 988 ft in the injection well at the fracturing plant site, used volumes of 2000, 50,000, and 23,000 gal. The fourth injection, with 50,000 gal of water containing fluid-loss additives, was made into a slot in the same well at a depth of 965 ft. The fluid-loss additives were 600 lb of bentonite, 800 lb of starch, and 250 lb of paraformaldehyde to prevent bacterial decomposition of the starch. The first test, which was terminated after four days, served primarily to establish the procedure used in the later tests. The final phase of the second, third, and fourth injections each extended over about 50 days.

The test procedure consisted of five phases: (1) injecting the water (or water plus fluid-loss additives); (2) shutting the well in for 48 hr and observing the drop in pressure – designated as the "first shut-in" phase; (3) opening the well for 48 hr, but limiting the flow rate to 10 gpm until the natural flow rate fell below this value, and observing the flow rate and volume backflowed as a function of time – designated as the "first backflow" phase; (4) shutting the well in again for 24 hr and observing the pressure rise as a function of time – designated as the "second shut-in" phase; and (5) reopening the well and observing the rate of flow and total cumulative volume recovered – designated as the "second backflow" phase.

WATER TEST RESULTS

First Phase (Injection)

In all four tests the breakdown pressures and the injection pressures required to extend the fracture were substantially above the overburden pressure, which is strong presumptive evidence that bedding-plane fractures had been formed (Fig. 4.1).

Second Phase (First Shut-In)

In all cases, when pumping was stopped and the well was shut in, the pressure fell from some higher value almost asymptotically down to the overburden pressure, although there was a very slow continued drop after this pressure had been reached (Fig. 4.2). Presumably this first shut-in phase represents the extension and squeezing shut of the fracture, which at the close of the injection is held open by a pressure greater than the weight of the overburden. This extension of the fracture continues until the fracture walls are sufficiently in contact so that the water need no longer carry the full load of the overburden. As the fracture is squeezed shut, the water must be forced out, either into the pores or minute fractures in the rock or, more probably, out along a bedding plane by a slow continuation of the fracturing. In a more permeable and more porous formation than the shale the fluid-loss additives would certainly reduce the rate of flow of water out into pores or minute fractures, but they appear to have had no influence on the injection pressures or fluid loss when fluid was injected into Conasauga shale. The similarity of the results in the five phases of the two 50,000-gal injections, with and without the fluid-loss addi-

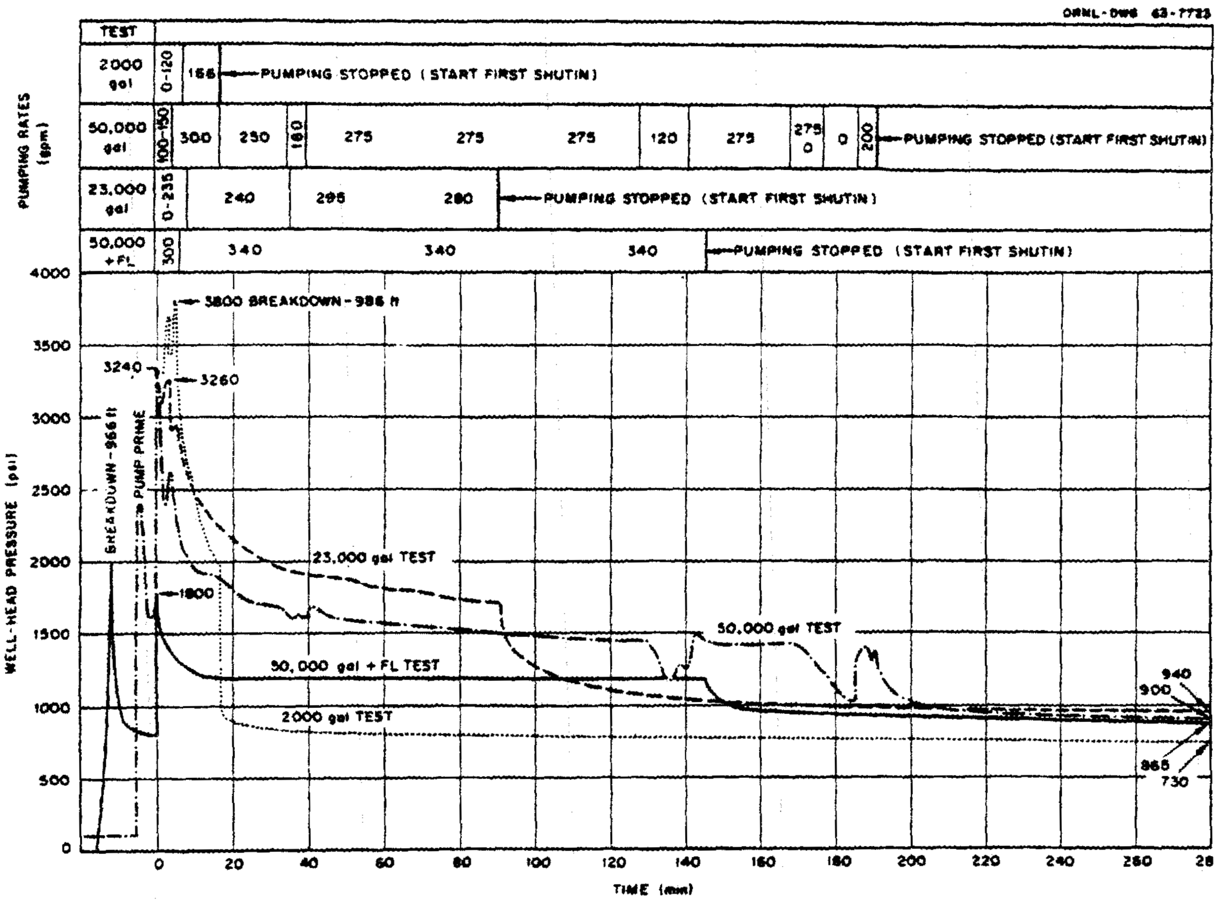

Fig. 4.1. Water Injection Tests – First Phase (Injection).

tives, clearly answers one of the original questions: Whatever the mechanism of fluid loss, the fluid-loss additives have little influence on its rate and are probably not required in the waste-cement mixtures.

Third Phase (First Backflow)

The length of time and the volume backflowed in order that the wellhead valve could be opened fully varied considerably between the three major injections and was one of the principal factors responsible for the differences in the volumes recovered during the first backflow phase of the tests (Fig. 4.3). The volume backflowed until the wellhead valve could be opened completely probably represents the volume that had to be removed in each case before the fracture near the well could close back tightly enough to limit the flow to no more than 10 gpm. This volume might be expected to vary considerably, depending on how smooth or ragged the fracture is near the well. Differences in smoothness may be due in part to the amount of shale eroded from the fracture walls near the injection well when the liquid was injected. The velocity of the

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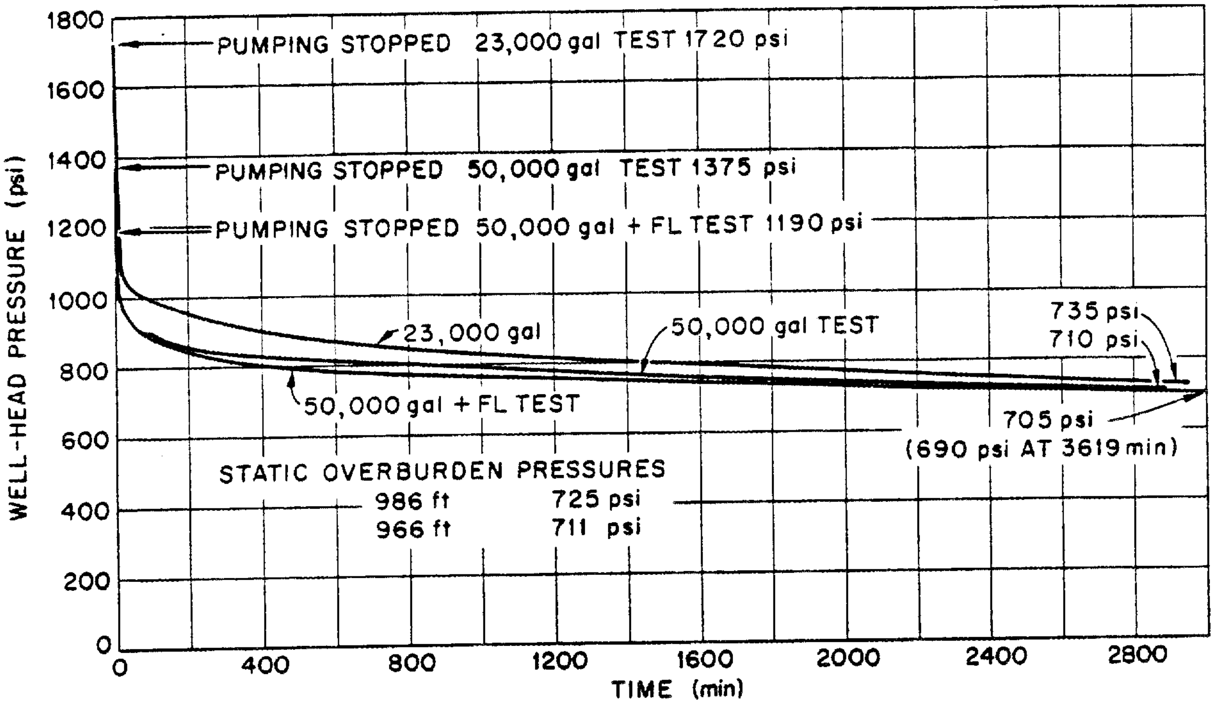

Fig. 4.2. Water Injection Tests – Second Phase (First Shut-In).

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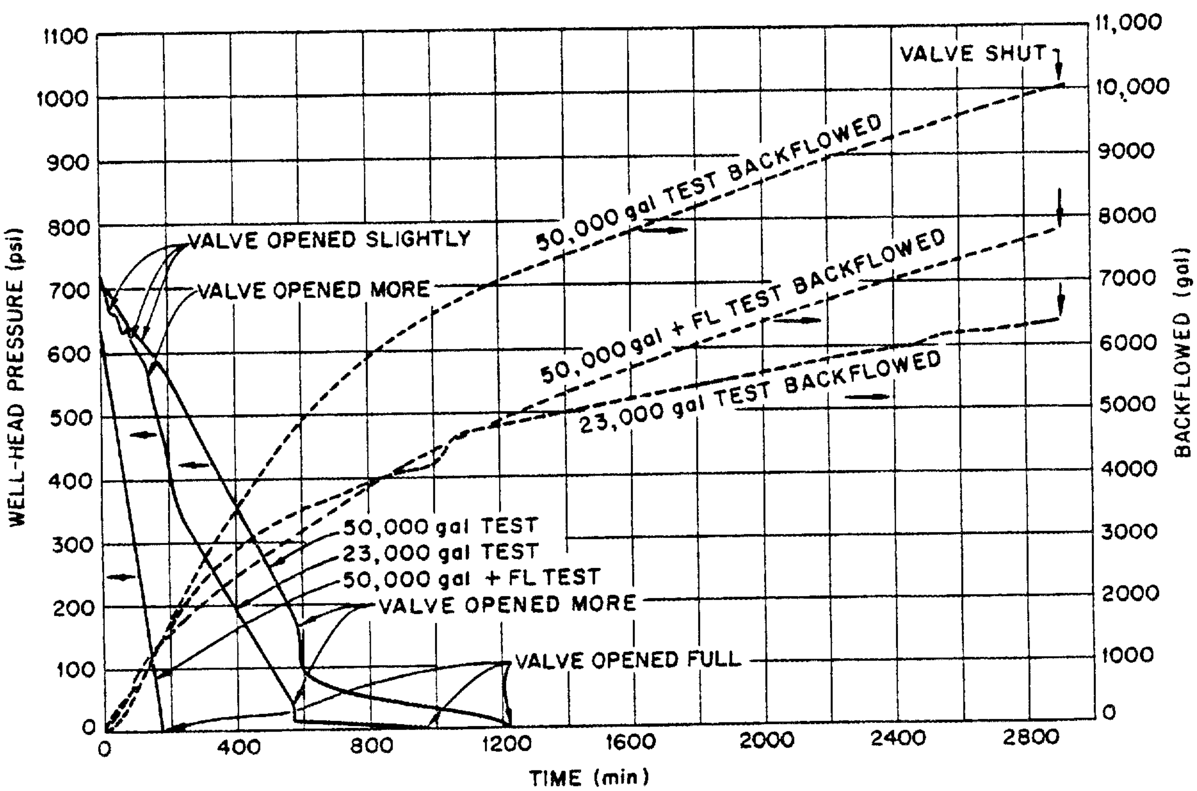

Fig. 4.3. Water Injection Tests – Third Phase (First Backflow).

fluid near the well is high enough to tear out pieces of the shale and carry them back into the fracture. In the first 50,000-gal injection (water only), about 7000 gal was backflowed before the valve on the wellhead could be fully opened. In the injection of 50,000 gal of water containing fluid-loss additives, a backflow of only 1350 gal of water was required. The rest of the curves, when plotted as volume backflowed vs time, have the same slope but are separated by a volume of 5650 gal, which is the difference between 7000 and 1350 gal. The factors controlling the flow during the second and longer part of this first backflow phase were therefore something other than the conditions immediately adjacent to the well and were much the same for the three major injections. Presumably the important factor was the squeezing shut of the outlying portions of the fracture.

Fourth Phase (Second Shut-In)

During the first backflow the pressure of the overlying rock forced the liquid back to and up the well, and there must have been a pressure gradient along the fracture. When the well was shut in, the flow continued until the pressure came to equilibrium at a value where the pressure in the liquid and the pressure of rock against rock just suffice to support the weight of the overburden (Fig. 4.4). The equilibrium pressure is therefore an indication of the proportion of the fracture still held open by the contained water. The time required to reach equilibrium is an indication of two things: the distances through which various volumes of water must move to establish this equilibrium and the transmissivity of the fracture. In the two 50,000-gal injections the equilibrium pressures had been reached after 24 hr and were almost identical for the two tests – 443 psi for the first and 450 psi for the second. However, the pressure increased toward the equilibrium value more rapidly in the test with fluid-loss additives. Other evidence, including the rates of flow and volumes recovered during the two backflow phases, suggest that the fracture at 965 ft was not more permeable than the other, but rather that the movement of a smaller volume of water was sufficient to establish equilibrium. The near identity of the equilibrium pressures is one of the reasons for believing that the fluid-loss additives had little effect on either the fracturing or the fluid loss under the conditions of these tests.

A total of 23,000 gal was recovered during the two backflow phases of the first 50,000-gal injection. If there had been no other fluid loss from the fracture and if the extent of the fracture had remained unchanged, the reintroduction of 23,000 gal into the fracture should have reestablished essentially the same conditions present at the close of the original injection; this is the reason why the third test consisted of pumping 23,000 gal back into this fracture. So many factors affect the injection pressure curve that the higher injection pressures required to put back the 23,000 gal cannot be explained. Local conditions near the well, quite possibly changed by the additional fracturing or the movement of rock chips during the second injection, could have affected the first part of the first backflow phase of the test and might even have reduced the total volume recovered during this relatively brief period. The time-pressure curve for the second shut-in phase of the 23,000-gal test rises much less rapidly than the curve for the two 50,000-gal

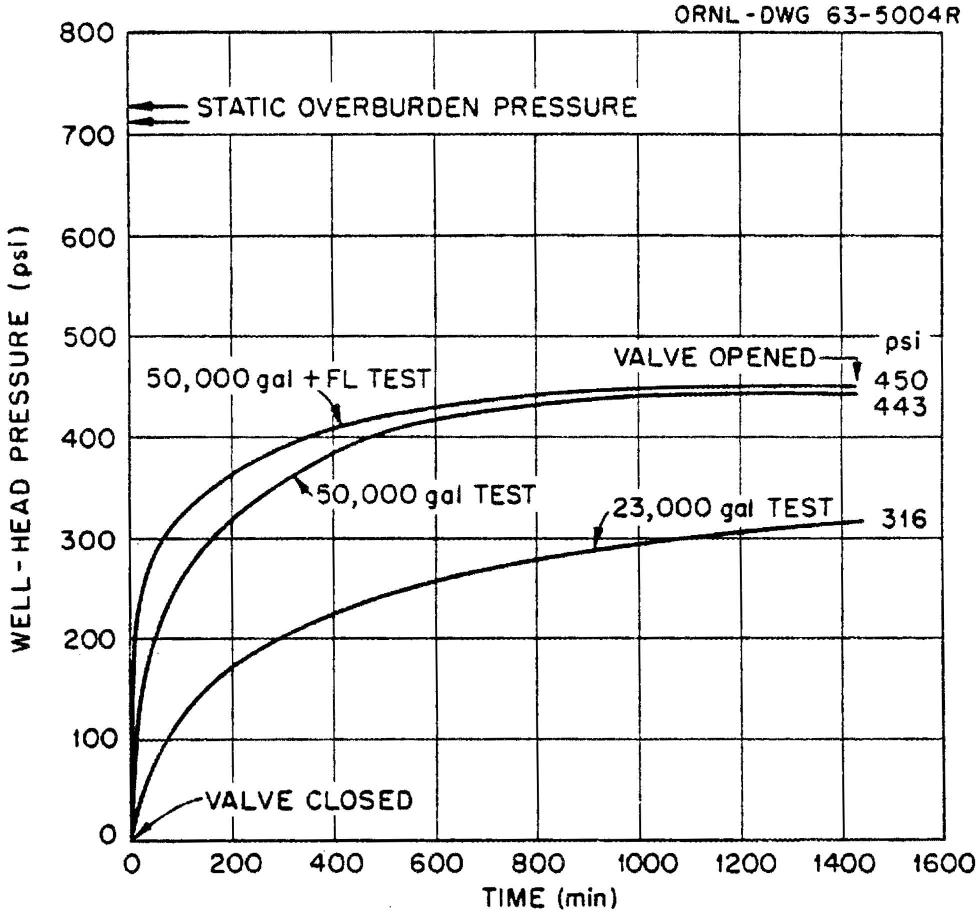

Fig. 4.4. Water Injection Tests – Fourth Phase (Second Shut-In).

tests, and equilibrium in the 23,000-gal test had not been reached at the end of 24 hr. The pressure after 24 hr shut-in was only 316 psi, and the slope of the curve suggests that the equilibrium pressure would be between 350 and 450 psi. The difference in slope could be explained by several factors, for example, a lower transmissivity of the fracture, as suggested also by the higher pumping pressures, or a further extension of the fracture during the second injection. The lower equilibrium pressure suggests that more of the overburden load was being carried by the rock, so more of the fracture must have squeezed back together. This in turn shows that the original conditions had not been reestablished by the reintroduction of the 23,000 gal and suggests additional fluid loss, but it does little to tell where the fluid went. Perhaps the missing fluid was trapped in outlying portions of the fracture formed during the first shut-in phase after pumping had stopped.

Fifth Phase (Final Backflow)

In the last three tests the wellhead pressure dropped to zero almost immediately, and it was possible to open the valve completely after only a few gallons had been recovered. The data recorded were the rate of flow and the volume recovered. The time-vs-rate curves for the two 50,000-gal injections were almost identical over the 50-day period required for this part of the test (Fig. 4.5). The flow rate from the 23,000-gal test fell much more rapidly with time for the first 100 hr after the final flowback was started, but then the curve flattened and after 900 hr joined and followed the time-rate curves of the earlier tests.

A plot of the volume of water remaining in the fracture, either as a function of time or as function of the rate of flow, makes it clear that even if these curves were extrapolated to infinity, a large portion, somewhere between a half and a third of the volume injected, would remain underground. In the first 50,000-gal test, 10,000 gal was recovered in the 48-hr first backflow and an additional 13,000 gal in the approximately 50 days of the second backflow, at which time the rate of flow was less than 2 gph and still declining. A total of 13,500 gal was recovered from the 23,000-gal test – 6400 gal in the first backflow. The recovery from the 50,000 gal of water containing fluid-loss additives after 50 days was slightly less than 23,000 gal. This final phase of the tests shows, as did the second shut-in, such a striking similarity between the injections with and without fluid-loss additives that whatever the mechanism of the fluid loss, it is not affected by the additives; consequently, there appears to be little incentive to use them.

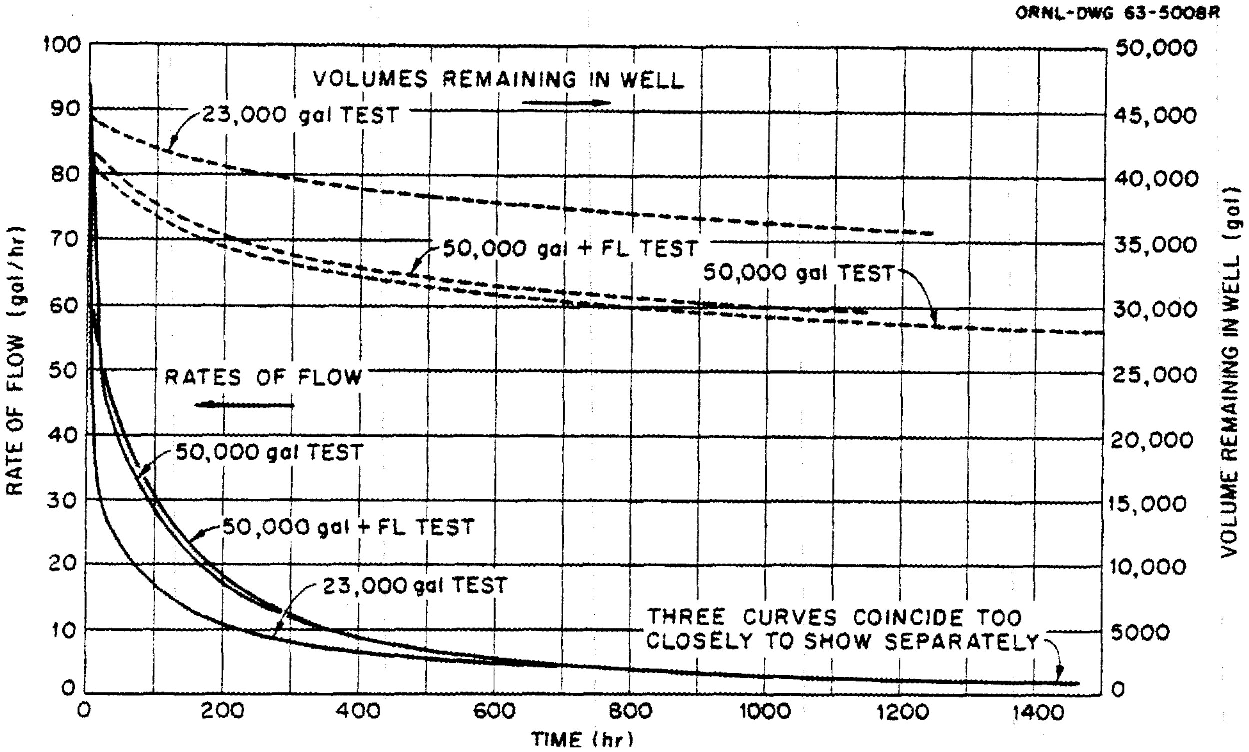

Fig. 4.5. Water Injection Tests – Fifth Phase (Final Backflow).

RECOMMENDATIONS FOR FUTURE TEST PROCEDURES

The planning of water injection tests for the preliminary evaluation of the fracture pattern created by hydraulic fracturing will depend on the stratigraphy and structure of the site in question. Therefore, the first requirement will be to obtain or prepare a map of the surface geology and from this to construct a provisional geologic cross section. The cross section will serve as a guide in selecting the most suitable depth intervals for fracturing, and these should then be explored by core drilling. Probably the greatest interest will be in comparatively impermeable shales, but the possibility of injecting liquid waste by fracturing directly into porous formations of low permeability should not be ignored.

Consideration of the results of the water injection tests at Oak Ridge suggests that too much emphasis was placed on injection pressures, that is, on the surface pressures required to initiate and extend a fracture. The pressures observed under dynamic conditions reflect not only the pressures required to overcome fluid friction in the well and in passing out of the slot in the bottom of the well casing, but also the pressures built up by fluid friction inside the fracture itself. There is therefore some doubt as to the validity of the concept of a single specific injection pressure, at least as the term was used in discussions with the Earth Sciences Committee in 1961. Clearly the breakdown pressures, which ranged from 2000 psi to 3800 psi in the four water injection tests of 1963, are not what was meant, for these depend on the strength of the rock immediately adjacent to the slot in the well casing prior to fracturing and not on the stress in the rock normal to the fracture. After breakdown, the pumping pressure falls more or less rapidly to some fairly constant value which appears to be, in part, a function of the rate of pumping. During the 50,000 gal of water plus fluid-loss additives test, this constant value was reached after about 15 min of pumping and, at an injection rate of 340 gpm, was some 1200 psi as measured at the surface. In the case of the 23,000-gal injection, there were two pressure peaks of 3240 and 3260 psi at the start of the injection, but after 90 min of pumping, at which time the injection was halted, the surface pressure was about 1700 psi and still falling slowly. The surface injection pressure, at a pumping rate of 280 gpm, appeared to be approaching a constant value of about 1600 psi. These unexplained variations support the belief that the dynamic conditions which exist while the injection is going on and the fracture is being actively extended are complex, and an explanation of the variations requires a consideration of many factors, some of which are poorly understood. Tests in which it is possible to measure pressures in the fracture, both while the pumping is in progress and also after the well is shut in, are most desirable.

In retrospect, the first shut-in phase of the test appears to be potentially the most informative. The concept of an instantaneous shut-in pressure, widely held in the petroleum industry, is easy to define but hard to apply. In theory, it is the pressure immediately after pumping has stopped and presumably represents a static condition in which the fluid, both in the well and in the fracture, is at rest, so that the surface pressure is a true indication of the pressure in the fracture without any pressure drop due to friction. In practice, a brief but yet finite time is required to stop the pumps. More importantly, after the pumps have stopped, the observed surface pressure drops rapidly at first, roughly 100 psi in the first minute and another 100 psi or more in the next 10 min. Initially, we attributed this drop to fluid loss, without considering too closely where the fluid might be going. Presently we are inclined to believe that the pressure drop, at least for the first few hours after the pumping has stopped, is due to continued extension of the fracture. In this, we have been influenced by the paper of Perkins and Kern on the widths of hydraulic fractures.[1]

To understand how the fracture can continue to extend after pumping has stopped, let us consider the pressure distribution in the fracture during the latter part of the period of pumping. At or near the tip of the fracture the fluid pressure must be sufficient to accomplish two tasks. First, the pressure must part the rock along one of the bedding planes. As the rock has little tensile strength normal to the bedding, this requirement is not very large. Second, the fluid must push up the rock cover against the force of gravity, for which a pressure just equal to the weight of the rock cover is required. In addition, the fluid pressure in the fracture adjacent to the well must be sufficiently higher than the fluid pressure near the tip of the fracture to force the fluid to flow out along the fracture against the resistance offered by fluid friction. The fluid pressure in the fracture, except near the tip, must therefore be greater than the weight of the overburden, and in order to retain this pressure, the rock cover and also the rock below the fracture must be deformed. This deformation will be elastic even though there is reason to believe that Young's modulus in most rocks is not constant but is a function of pressure. If the rock walls are deformed elastically, work is stored in them. When pumping stops, the rate of flow of the fluid in the fracture decreases and the fluid pressure tends to equalize. In consequence, the pressure near the tip of the fracture increases, or rather tends to increase, because as the pressure at the tip starts to rise the fracture is extended. Back nearer the injection well the pressure tends to drop, but as it does the elastically deformed rock walls close back together. In this way the work stored in the deformed rock is used to extend the fracture, as stated by Perkins and Kern. This continued extension of the fracture after the well is shut in proceeds at a decreasing rate and is the principal reason for the continued drop in pressure after pumping stops. If it were the only reason, the pressure in the fracture would approach the overburden pressure asymptotically. In the three main water injection tests, the pressure did indeed tend to do this during the first shut-in phase but afterward continued to drop very slowly.

We have no record of the pressures during and after the formation of a vertical fracture because, as far as we know, none have been formed by any of our injections. However, many of the same factors would be involved. The injection pressure observed while the pumps are operating would be the pressure required to hold open and extend the fracture plus the pressure gradient in the fracture required to overcome internal fluid friction. The pressure at or near the tip of the

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[1]T. K. Perkins and L. R. Kern, "Widths of Hydraulic Fractures," *J. Petrol. Technol.* 13, 937—49 (September 1961).

advancing fracture would be equal to the pressure normal to the fracture plus the pressure required to rupture the rock. If we restrict our consideration to well-bedded rock such as shale, with the beds horizontal, a vertical fracture will differ from a horizontal fracture in that the pressure required to rupture the rock may not be negligible.

As we have seen, the pressure in the injection well while injection of fluid is under way is the sum of several factors. In addition to the pressure required at the tip of the fracture, the injection pressure must provide for the pressure gradient needed to overcome friction losses in the fracture. The fluid friction in the fracture will depend, in part, on the smoothness of the walls of the fracture and on the fracture width. A fracture formed by shearing normal to the bedding, to judge from the small faults observed in the shale, may well be as smooth as a fracture formed by pressure parting of the beds. We have no information as to the probable smoothness of a fracture normal to bedding formed by tension, as the hydraulically formed fractures are, but they might well be ragged. Other things being equal, the permeability of a fracture is proportional to the third power of the width of the fracture, and consequently, for a given rate of pumping, the fracture width will be much the same whether the fracture is vertical or horizontal. This presumes, of course, that the well is cased and that the fracturing results from pumping fluid out through a horizontal slot in the casing. In the case of a horizontal fracture, the necessary fracture width is produced by lifting the overburden and by deforming the cover rock. In the case of a vertical fracture, the width of the fracture is provided by overcoming the horizontal stress in the rock, which for a vertical fracture is assumed to be less than the weight of the overburden, and also by compressing the rock horizontally. The pressure required to compress the rock sufficiently to form the required fracture width will depend rather closely on Young's modulus for the rock, about which, for shale, we have little information, particularly parallel to the bedding. There will be some uplift of the overburden, depending on Poisson's ratio for the rock, another property on which we have few data, but this part of the problem is relatively unimportant. However, because of the potentially higher pressures required to overcome fluid friction and to hold the fracture open, the observed wellhead pressures during the formation of a vertical fracture may well be as high as those experienced when a horizontal fracture is being formed, at least down to depths of 2000 or 3000 ft. Much the same line of reasoning led Perkins and Kern to the same conclusion. Therefore, under dynamic conditions, the observed wellhead or bottom-hole pressures must be interpreted with caution.

However, when pumping is stopped and the well is shut in, the pressure in the well and in the fracture adjacent to the well, as a first approximation, should drop asymptotically toward a value equal to the stress in the rock normal to the fracture, the stress required to rupture the rock. For a vertical fracture, this pressure should be less than the weight of the overburden. However, the true fluid loss from a vertical fracture in shale may be higher than that for a horizontal fracture because a vertical fracture will intercept many more bedding planes, and it also has a better chance of cutting a relatively permeable bed. The time-pressure curves for the first shut-in phase, when a vertical fracture has been formed, may not asymptotically approach the value of the stress in the rock normal to the fracture, and if fluid loss should be relatively rapid the curve may not appear to approach any value asymptotically. Following the formation of a vertical fracture, only if the tensile strength of the rock and the permeability of the rock are both low when measured parallel to the bedding will the time-pressure curve for the first shut-in phase approach the value of the stress normal to the fracture unambiguously.

It may be of interest at this point to examine the data from a fracturing test with water made in a well in west central Indiana.[2] The well in question was a gas or oil "wildcat" drilled in 1959 to a depth of 1982 ft and then plugged back and abandoned. The log showed that the well had penetrated several hundred feet of shale which extended approximately from about 800 or 900 ft to over 1500 ft below the surface. Early in 1962 the well was cleaned out to depth of 1282 ft, and a 5½-in. 14-lb J-55 casing was cemented in to that depth. The plug on top of the cement in the casing was set at 1179 ft. Cement returns were not obtained at the surface, presumably because of a washout or loss of the cement grout to a permeable zone or to a fracture. Despite this possible weakness in the cement job, after the cement had ample time to set, the casing was slotted at 1175 ft with a sand-water jet. Attempts were then made to initiate a fracture at 2100 and at 2500 psi and finally were successful at a surface pressure of 3000 psi (Fig. 4.6). After the initial breakdown, the pressure was relieved for about 5 min while the wellhead connections were tightened. Injection was then resumed at 1500 psi, followed by a brief

[2] No report on this test has been published. The data quoted are from a personal letter written by one of the engineers concerned.

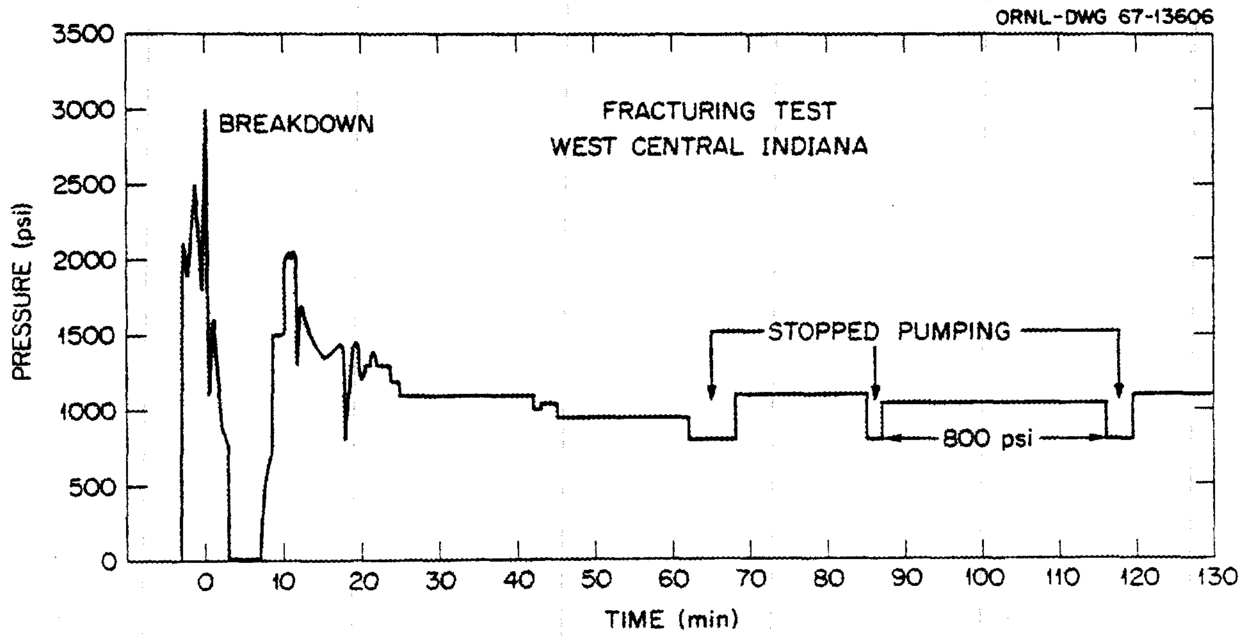

Fig. 4.6. Fracturing Test – West Central Indiana.

increase in pressure to 2000 psi. During the next 15 min, at pumping rates of from 400 to 600 gpm, the wellhead pressure dropped slowly to 1200 psi, but there were a few momentary drops in pressure to 800 or 1000 psi which could not be explained. After about 15 min of pumping, the pressure remained nearly stable, but dropped slowly from 1200 to 1100 psi over a period of about 20 min. At this time pumping was stopped briefly in order to connect the pump to a new tank truck; the water being pumped into the well had to be trucked in. During the brief shut-in the wellhead pressure dropped almost immediately to 800 psi, but it returned to 1100 psi when pumping was resumed at a rate of 575 gpm. Pumping was stopped periodically while 17 truckloads of 6500 gal each were pumped in, for a total of 110,000 gal in $6\frac{1}{2}$ hr. Each time pumping stopped, the wellhead pressure dropped immediately to 800 psi, at which it rested. After the 12th load of water had been pumped in, the well was backflowed, when the pressure dropped nearly to zero, but it came back up to 800 psi immediately when the well was shut in. A thousand pounds of coarse sand and 200 lb of rounded fragments of walnut shell were injected into the fracture with the last of the water. When pumping was finally stopped, the instantaneous shut-in pressure was reported as 850 psi, but this dropped almost immediately to 800 psi. After several weeks the pressure gradually dropped to 300 or 400 psi, but no details are available as to this part of the test.

The engineers responsible for the test believed it had been a failure and that the water had broken up along the casing and then fractured out into wall rock at relatively shallow depth. Their reason for believing this was based on the several "breaks" in pressure during the first 15 min of pumping and the fact that the static wellhead pressure did not remain at 800 psi indefinitely but fell slowly to 300 or 400 psi over a period of several weeks.

In view of the preceding discussion this explanation appears very unlikely. At a depth of 1175 ft the weight of the overburden would be about 1300 psi, if the specific gravity of the overburden were 2.6, and the static surface pressure of a well filled with water would be 815 psi. The shut-in pressure of about 800 psi strongly suggests therefore that a horizontal fracture had been formed. This is also indicated by the relatively high pumping pressure, but not as certainly, for the friction losses are unknown. The quick return to the overburden pressure when pumping stopped cannot be easily explained, but perhaps these shales were less well indurated than the shale at Oak Ridge and therefore stored less elastic energy when the shale was deformed to provide for the width of the fracture.

Such a test in an area that was under consideration for waste disposal by hydraulic fracturing would be regarded as highly favorable. However, before constructing the disposal plant it would be desirable to confirm the results of the water injection by making a similar test with tagged grout and then drilling test wells to find out where the grout had gone. Since much of the expense of these tests is in the test wells, it would probably be advisable to make several injections of tagged grout at different depths, as this would provide positive evidence of the fracture pattern with only a small additional expense.

5. Mix Development

The fracturing tests at Oak Ridge made the need for the chemical development of injection mixes abundantly clear. Following the second experiment, for example, the repeatedly reopened injection well leaked fluid long after the slurry had set up, indicating that some of the water had not been incorporated in the set grout.[1] In several of the cores recovered subsequently, multiple grout sheets from a single injection were found, suggesting that the leading edge of the cement-water slurry may have been dehydrated as it extended out into the fracture and as a result may have induced the formation of new fractures, which started back at the well bore and extended out from it as the injection continued. These observations of the injections made with water-cement mixtures and others discussed elsewhere in this report suggested the need for careful development of waste-cement mixes which could be injected satisfactorily into the local formation.

In developing waste-cement mixes, attention was first given to *safety*. Rigid requirements were established for what we hoped would be an acceptable mix, but our decisions were based on inadequate information concerning the porosity and permeability of the host rock. When more adequate information was obtained, some of the requirements were relaxed or eliminated; and as laboratory data were obtained, we gained confidence in our ability to control the behavior of mixes. With time, these developments permitted focusing our attention on the *cost* of mixes; and when the use of hydrofracturing to dispose routinely of ORNL's evaporator concentrates became a possibility, our efforts were concentrated on developing *safe* and *economical* mixes.

During the course of this development program, many materials were tested. Some were eliminated because they were found to be unnecessary; others were eliminated because the ORNL waste solution interacted unfavorably with them. In the latter case, other waste solutions may prove to be compatible with these various materials. Wherever possible, reasons for rejecting materials are given. Both positive and negative results are included so that in other situations and in other applications attention may be given to these materials in formulating suitable mixes.

To aid us in mix development, the cooperation of the petroleum industry was solicited; and contracts were awarded to Westco Research of Dallas, Texas, and later to Halliburton Company of Duncan, Oklahoma, to work with us. Their technical contributions are gratefully acknowledged. Their experience and knowledge during all stages of development helped in reaching the goal set for this program.

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[1]W. de Laguna, "Disposal of Radioactive Waste by Hydraulic Fracturing. Part II. Mechanics of Fracture Formation and Design of Observation and Monitoring Wells," *Nucl. Eng. Design* 3, 432–38 (1966).

PRELIMINARY MIX SPECIFICATIONS

The specifications for waste mixes were first set on the basis of some preliminary laboratory tests with synthetic 1X waste and several trial formulations. These specifications are shown in Table 5.1.

Table 5.1. Preliminary Waste-Mix Specifications

Viscosity (consistency)	<20 poises
Thickening time (pumping time)	8 hr, minimum for 1000-ft "squeeze" schedule
Setting time	7 days, max
Compressive strength (cured at 1 atm)	100 psi
Fluid loss (100-psi test)	<60 cc in 30 min
Phase separation (free liquid)	None

Thickening time, or pumping time, is the interval during which the slurry must remain pumpable, that is, be capable of being pumped down the injection well and out into the fracture. Thickening time was based on a 1000-ft schedule, which calls for 3300 psi pressure and a temperature of 89°F.[2]

The specification on acceptable fluid loss was a stringent one. (This was determined by a standard test used in the petroleum industry to measure the rate at which fluid leaks out of the cement slurries used in oil-well construction. A gelatinous precipitate like ferrous hydroxide would have a low fluid loss; sand and water a high fluid loss.) Since we had no knowledge of the possible rate of escape of fluid from the slurry into the shale formation, we arbitrarily selected a value of less than 60 cc in 30 min at 100 psi, which is about one-tenth of that considered acceptable in conventional cement-water slurries. It was feared that a high loss of fluid to the formation would thicken the slurry and prevent its spread out into the formation. The requirement was relaxed later when field tests showed that the rock was itself sufficiently impervious to prevent fluid from escaping. The requirement that no free liquid remain after setting was imposed after the first field tests had shown some bleedback of water from the fracture due to phase separation. This bleedback showed again the impermeability of the shale and served as additional justification to relax the initial requirement of low fluid loss.

Our problem was to develop pumpable slurries whose viscosity would remain low and whose consistency would remain stable during the several hours required to complete an injection, but

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[2]American Petroleum Institute, *Recommended Practice for Testing Oil-Well Cements and Cement Additives*, API RP 10B (10th ed.), March 1961, API Division of Petroleum, Dallas, Tex.

which would set soon after completion of the injection. In addition, no free liquid phase should separate out, for a free liquid might make its way back up to zones of circulating groundwater or to the surface. Since plans for eventual use of the method included the disposal of large volumes of liquid waste, attention was limited to those materials whose performance had been proven in large-scale usage.

At first, to evaluate our slurries we used the standard testing procedures recommended by the American Petroleum Institute.[2] Later, modifications in testing procedure were made when we realized that mixes for use in hydraulic fracturing must meet requirements very different from those applicable to oil-well cementing. The principal change in test procedure was to ensure that the method of mixing test samples in the laboratory duplicated conditions in the field.

WASTE SOLUTION COMPOSITION

The chemical composition of the simulated waste solution used in most of the laboratory tests was that of ORNL's intermediate-level waste. Actual wastes at ORNL arise as acid solutions from a variety of operations, including chemical research with radioisotopes, metallurgical research with irradiated materials, hot-cell work associated with development of reactor fuel reprocessing methods, and chemical separations for the recovery and sale of radioisotopes. These solutions are collected in steel tanks, neutralized with excess caustic, and pumped to a central tank farm for temporary storage. In the past the supernatant liquid was pumped to a nearby site and discharged into seepage trenches excavated in the Conasauga shale formation. This highly alkaline waste, whose nominal composition is shown in Table 5.2, came to be known as 1X waste.

Table 5.2. Nominal Composition of ORNL 1X Waste

Chemical	Concentration (*M*)	Radionuclide	Concentration (mc/liter)
NaOH	0.22	^{90}Sr	2.8×10^{-3}
$NaNO_3$	0.32	^{137}Cs	6.5×10^{-1}
Na_2SO_4	0.04	^{106}Ru	8.3×10^{-1}
$Al(NO_3)_3$	0.02	^{144}Ce	2.9×10^{-3}
NH_4NO_3	0.2	^{60}Co	5.9×10^{-4}
NaCl	0.006	^{95}Zr-^{95}Nb	3.5×10^{-7}

The aluminum in this waste is present as the aluminate ion. The ^{90}Sr content is low due to the treatment with caustic, which causes strontium to coprecipitate with the calcium carbonate formed and settled in the storage tank. In such an alkaline medium, most of the ^{60}Co, ^{144}Ce, and ^{95}Zr-^{95}Nb are presumably present as hydrous oxides or hydroxides. The ^{106}Ru is present as a nitroso complex, and several cationic and anionic forms appear to exist in 1X waste.[3] Cesium-137 is not only one of the most abundant radionuclides in the waste but has a long half-life, as does ^{90}Sr.

While work on the shale fracturing program was still in an early stage, the Laboratory decided, for reasons quite apart from any of our research, to reduce the volume of 1X waste. In consequence, plans were laid for the installation of a steam-heat single-stage evaporator which was to have a maximum throughput of approximately 650 gal/hr with a volume reduction of about a factor of 10, thus producing a concentrated waste (10X) whose composition would be approximately ten times the concentration of 1X waste shown in Table 5.2. The development of mixes for hydraulic fracturing was directed toward disposal of both the 1X and 10X wastes, since successful disposal would both demonstrate the process and fill a real need at the Laboratory. Hence, the mix development work was extended to mixes which would be compatible with the expected high dissolved-salt content of 10X waste as well as the normal 1X waste, even though it was known that evaporator concentrate would not be available for field testing for some time.

MIX DEVELOPMENT – PHASE I

Preliminary Compatibility Tests

Since waste solutions contain appreciable salts and caustic, it was necessary to establish their compatibility with portland cement. Portland cement was selected as the base ingredient because the petroleum service companies had considerable know-how concerning its procurement and performance.

After mixing in a Waring Blendor (a 1-quart-size propeller-type mixer capable of rotating 4000 rpm at no load on "slow" speed and 10,000 rpm or more at no load on "high" speed) according to the procedure recommended by API, the slurry was visually inspected for evidence of flash setting, initial gel strength, and consistency. Flash setting and high initial gel strength are dependent on the chemical composition both of the cement and of the waste solution, and consistency is affected by the solution-to-cement ratio and the initial hardening process. A solution/cement ratio of 208 cc/lb is recommended by API for slurries prepared from distilled water and type I cement.[2] Slurries had a high initial gel strength when prepared from Volunteer type I cement and 208 cc of waste per pound of cement but not when the proportions of waste were greater (Table 5.3). Note that the source of cement affected the behavior of the slurry; and because different batches showed different properties, it was decided to limit our studies to cement obtained from the Volunteer Cement Company at Knoxville, Tennessee, the source closest to ORNL.

Slurries containing Volunteer cement were tested further to obtain information on fluid loss, thickening time, and compressive strength (setting characteristics). These results are shown in Table 5.4. Waste-cement slurries exhibited relatively short thickening times and high fluid losses,

[3]H. O. Weeren, "Disposal of Radioactive Wastes by Hydraulic Fracturing. Part III. Design of ORNL's Shale-Fracturing Plant," *Nucl. Eng. Design* 4, 108–17 (1966).

Table 5.3. Quality of Waste-Cement Slurries After Blending

Cement Source	Solution Used	Solution/Cement Ratio (cc/g)	Flash Setting	High Initial Gel Strength	Pourability
Trinity Cement Co., Dallas, Tex.	Distilled water	208/454	No	No	Yes
	Distilled water	170/454	No	No	Yes
	Distilled water	163/454	No	No	No
	Waste	208/454	No	No	Yes
Volunteer Cement Co., Knoxville, Tenn.	Distilled water	208/454	No	No	Yes
	Waste	208/454	No	Yes	No
	Waste	220/454	No	No	Yes
	Waste	245/454	No	No	Yes

properties similar to those obtained with water. Additives are available which are commonly used in the petroleum industry to modify cement slurries.[4] Hence, addition of 0.8% calcium lignosulfonate (CLS) increased the thickening time from 2 hr 26 min (2:26) to 10 hr 57 min (10:57). Fluid loss, however, was not reduced substantially until bentonite was added. Addition of 6% bentonite reduced the fluid loss from approximately 400 to 185 cc; with 12% bentonite, the fluid loss was reduced to approximately 100 cc. Note that the thickening time was reduced by the addition of bentonite. Throughout the investigation it was found that addition of one material caused changes in properties other than the one intended, necessitating further changes in the proportioning of other additives.

The addition of bentonite to a cement slurry requires an increased amount of solution because bentonite is a sorbent for water and the loss of interparticle water causes an increase in slurry consistency. This also decreases the cost of the mix, which is desirable. The addition of CLS, primarily to extend the thickening time, reduces slurry consistency, thus counteracting the effect of bentonite.

Additives to Reduce Fluid Loss

Since the reduction of fluid loss by the addition of bentonite did not satisfy the minimum requirements set in the preliminary specifications (Table 5.1), it was decided to investigate other additives which might be more effective. Table 5.5 lists some of the materials tested for this purpose.

[4]American Petroleum Institute, *Oil Well Cementing Practices in the United States*, American Petroleum Institute, 50 West 50th St., New York, 1959.

Table 5.4. Properties of Slurries Prepared from Synthetic Waste Solutions

Slurry No.	CLS[a] (%)	Bulking Material	W/C Ratio[b] (cc/lb)	Fluid Loss (cc/50 min at 100 psi)	Thickening Time to 100 Poises (hr:min)			Compressive Strength (psi after 24 hr)		
					1000-ft Schedule	3000-ft Schedule	5000-ft Schedule	80°F	110°F	140°F
1			208, distilled water	608	2:50		2:05	1000	2003	3750
2			208, IX	538	2:26	2:10	1:18	1560	1830	3220
3	0.3		208, IX		3:46					
4	0.8		208, IX	406	10:57			375[c]		1169[c]
5	0.8	Bentonite, 6%	265, IX	185						
6	0.6	Bentonite, 12%	322, IX	116						
7	0.8	Bentonite, 12%	322, IX	108						
8	1.2	Bentonite, 12%	322, IX	82						
9	0.8	Bentonite, 6%	250, IX	161	4:42		5:30		i.s.[d]	
10	0.6	Bentonite, 6%	265, IX	194	4:19			f.s.[e]		

[a]CLS = calcium lignosulfonate.
[b]Ratio of waste or water to cement.
[c]Compressive strength after 48 hr.
[d]Initial set.
[e]Final set.

Table 5.5. Screening Tests of Fluid Loss Additives

Material	Concentration (%)	W/C Ratio[a] (cc/lb)	Fluid Loss[b] (cc)	Comments
Carboxymethyl cellulose (CMC)	2	245, water		Slurry gels; high fluid loss
Ethylhydroxyethyl cellulose (EHEC)	2	220, water		Dehydrated in 1 min 15 sec
	6	250, water		Dehydrated in 1 min 15 sec
Ben A Gel	0.7	300, water		Dehydrated in 2 min
	2.8	300, water		Dehydrated in 2 min 12 sec
Carboxymethyl hydroxy ethyl cellulose (CMHEC)	1.0	300, water	60	
	1.0	300, waste	14	
Polyvinyl alcohol	0.5	208, water		Dehydrated in 1 min 0 sec
	4.0	208, waste		Dehydrated in 6 min 7 sec
Sodium silicate	6	208, waste		Dehydrated in 1 min 30 sec
Baroco drilling clay	1	208, water		Dehydrated in 1 min 0 sec
Cemad-1	1	208, water	4	
	1	208, waste	21	
ET-181-6	1.5	208, water	14	
	1.5	208, waste	46	

[a]Ratio of waste or water to cement.
[b]Fluid loss measured at 100 psi for 30 min.

Most of them failed to satisfy the requirements. In most instances, the slurry dehydrated before the end of the 30-min test period. This behavior indicated that the fluid escaped rapidly through a 44-μ-diam sieve and, in several minutes, allowed the nitrogen gas used to pressurize the cell to escape through the solid. Only three of the materials appeared promising — CMHEC, Cemad-1, and ET-181-6. These were selected for further study. It should be remembered that these studies did not involve tests of materials over a wide range of waste concentrations; hence, with other wastes and for other applications, other materials may be useful and should be evaluated.

Table 5.6 gives the results of tests with mixes containing the three fluid loss additives selected for detailed study. Thickening times and compressive strength data are included where obtained. The preliminary mix specifications (Table 5.1) were met with each of these fluid loss additives by adjustments in proportioning of the other materials. In addition to bentonite clay, it was found that Grundite, a commercial illite clay, could be used without causing drastic changes in the desired slurry properties.

Tests of mixes made up to the same formula showed unexplained variations in thickening time. Small amounts of calcium chloride (0.5%) were added to several mixes containing Cemad-1 to test its influence on the variability of thickening time. Calcium chloride is frequently used to ensure set of retarded slurries.*

The addition of calcium chloride was discontinued when the tests showed that variability in thickening time existed even with mixes containing calcium (see, e.g., the results with mixes 11 and 12). In the CMHEC mixes, about 2% silica flour was added to several formulations. Again, this was done since variability in thickening time was observed with the same formulations. Additions of silica flour, however, did not remedy the problem (see mix 24).

The variability of thickening time with the same formulation posed a serious problem. Several factors which might have been responsible for the variable results were evaluated:

1. faulty Consistometer,
2. contaminants present in the salts used to prepare simulated waste solution at different times,
3. absorption of carbon dioxide from the atmosphere by the waste solution,
4. insufficient quantities of silica flour,
5. change in the quality of cement from the supplier.

All the factors were checked, and each was eliminated as a causative factor except item 5. Since cement is known to change with age, it is customary to request fresh samples periodically. Test showed that the age of the waste solution was not a factor, but the age of the cement did affect the thickening time. Hence, the cement was judged to be responsible for the variations. Discussions with the supplier revealed that he had substituted anhydrite for gypsum in manufacturing the cement. Anhydrite reduces the setting time for cement, and for most applications this is desirable. As a consequence, later requests for a cement sample always specified that gypsum-retarded cement was wanted.

The three mixes which appeared most promising for use with 1X ORNL waste were mixes 8, 11, and 22 in Table 5.6. After testing several replications of these mixes, we were able to settle on the average values for fluid loss, thickening time, and compressive strength shown in Table 5.7.

Radionuclide Retention in High-Cement Mixes

The ultimate objective of the hydraulic fracturing project was to develop a safe and economical method of radioactive waste disposal. What happens to the radionuclides is of prime importance; we want to retain the radionuclides in the set grout once it has been pumped into the ground and

Table 5.6. Thickening Time, Fluid Loss, and Compressive Strength of Mixes Prepared with Three Different Fluid Loss Additives

Mix No.	FLA[a] (%)	CLS (%)	Bulking Material	W/C Ratio (cc/lb)	Fluid Loss (cc/30 min)	Thickening Time (hr:min for 1000-ft schedule)	Compressive Strength (psi after 24 hr and 80°F curing)	Other Additives
						ET-181-6		
1	1.0	0	None	208	91			
2	1.3	0	None	208	51			
3	1.5	0	None	208	46			
4	1.3	0.7	None	332	45			
5	1.3	0.7	Bentonite, 6%	332	31			
6	1.3	0.7	Bentonite, 6%	250	17	5:00	57	
7	1.3	0.8	Bentonite, 6%	250	10	10:40	2000[b]	
8	1.3	1.0	Bentonite, 6%	250	12	21:05	2800[b]	
						Cemad-1		
9	1.0	0.7	Bentonite, 6%	332	59			$CaCl_2$, 0.5%
10	1.5	0.7	Bentonite, 6%	332	34			$CaCl_2$, 0.5%
11	2.0	0.7	Bentonite, 6%	332	13	10:25 and 13:15	75	$CaCl_2$, 0.5%
12		0.7	Bentonite, 6%	332	38	15:25 and 8:35		
13	2.0	1.0	Bentonite, 6%	332	22	15:00[c]	575[b]	$CaCl_2$, 0.5%
14	2.0	1.0	Bentonite, 6%	332	43			
15	2.0	0.7	Grundite, 6%	332	17			$CaCl_2$, 0.5%
16	2.0	0	Grundite, 3% Bentonite, 3%	332	18	2:30		
17	2.0	0.5	Grundite, 3% Bentonite, 3%		10	7:54	2.0	
18	2.0	0.7	Grundite, 3%	344	32	12:00	770[b]	
						CMHEC		
19	0.3	0.6	Bentonite, 6%	265	171	16:45		
20	0.5	0.6	Bentonite, 6%	265	102			
21	1.0	0.6	Bentonite, 6%	265	28			
22	0.8	0.8	Bentonite, 6%	265	16	49:45	1050[d]	Silica flour, 2%
23	0.8	0.5	Bentonite, 6%	265	16	29:37	1080[d]	Silica flour, 2%
24	0.5	0.8	Bentonite, 6%	265	60	51:30		Silica flour, 2%
						52:20		
						21:15		
						18:19	2450[d]	Silica flour, 2%

[a]Fluid loss additive.
[b]After three days curing.
[c]For 3000-ft schedule.
[d]After seven days curing.

Table 5.7. Thickening Time, Fluid Loss, and Compressive Strength of Three Acceptable Mixes

Mix No.	W/C Ratio[a]	Bentonite (%)	CLS[b] (%)	Fluid Loss Additive	Thickening Time for 1000-ft Squeeze Schedule (hr:min)	Fluid Loss (cc/30 min)	Compressive Strength		
							Curing Temp. (°F)	Curing Time (days)	Strength (psi)
1	250	6	1.0	ET 181-6, 1.3%	24:30	19.5	80	1	i. s.[c]
							80	5	2590
2	322	6	0.7	Cemad, 2.2%	10:25	13	80	1	75
							110	5	50
							110	7	470
3	265	6	0.8	CMHEC, 0.8%	49:45	16	80	4	n. s.[c]
							80	5	120
							80	7	1050

[a] Waste/cement ratio.
[b] Calcium lignosulfonate.
[c] i. s. = initial set; n. s. = no set.

incorporated into the disposal formation. If fluid loss were to occur during the injection or if phase separation should develop during setting, the failure to retain the radionuclides in the solid phase of the slurry or grout would increase the potential hazard of the method. The best mixes were therefore tested to determine the radionuclides lost through fluid loss and the radionuclides lost when a mix which had set and had cured for seven days was subjected to leaching.

Measurements were made of the amount of radiocesium and radiostrontium which might escape by fluid loss into the formation. Results showed that both radiocesium and radiostrontium reacted rapidly with the solids in the mix and were removed from the liquid phase (Tables 5.8 and 5.9). Radiocesium activity was reduced in the liquid phase by about 70%, and inspection of the data revealed that bentonite was the additive responsible for cesium retention in the slurry. Bentonite, then, provided an additional benefit, namely that of sorbing the radiocesium, in addition to reducing fluid loss and cost.

Very little ^{90}Sr was found in the fluid phase after contact with solids (Table 5.9). Variations in the composition of the mix had no appreciable effect on ^{90}Sr retention. The important factor in

Table 5.8. Cesium Activity in Filtrate from Fluid Loss Tests

Mix No.	Fluid Loss Additive	Fluid Loss (cc/30 min)	Activity (counts min^{-1} ml^{-1})		Reduction (%)	Percent of Total Activity Lost in Filtrate
			Waste	Filtrate		
1	CMHEC, 1.0%	9.3	27,400	7,625	72	0.98
2	CMHEC, 1.0%	7.8	27,200	7,270	73	0.79
3	CMHEC, 1.0%	8.6	27,400	7,100	74	0.84
4	CMHEC, 0.5%	29.6	27,190	8,460	69	3.48
5	CMHEC, 0.5%	27.5	27,000	7,945	70	3.05
6	CMHEC, 0.5%	43[a]	26,990	9,175	66	5.52
7	CMHEC, 0.5%	44[a]	26,890	8,417	65	5.82
8	Cemad, 1.0%	23.8	27,300	8,615	68	2.83
9	Cemad, 1.0%	23.6	27,000	8,680	68	2.85
10	ET-181-6, 1%	107[b]	27,130	8,575	68	
11	ET-181-6, 1%	85[b]	27,220	8,810	68	
12	None	73	27,280	8,805	68	8.89
13	None	72	26,780	8,280	69	8.41
14	None	53[c]	27,130	24,240	11	
15	None	68[c]	27,110	25,050	8	

[a]No calcium lignosulfonate in these mixes.

[b]These mixes flash set; pressurizing gas leaked through slurry before test was completed.

[c]No fluid loss additive, calcium lignosulfonate, or bentonite. Pressurizing gas leaked through slurry before test was completed.

Table 5.9. Strontium Activity in Filtrate from Fluid Loss Tests

Mix No.	Fluid Loss Additive	Fluid Loss (cc/30 min)	Activity (counts min^{-1} ml^{-1}) Waste	Activity (counts min^{-1} ml^{-1}) Filtrate	Activity Reduction (%)	Percent of Total Activity Lost in Filtrate
16	CMHEC, 1.0%	10.5	26,370	1,625	93.8	0.24
17	CMHEC, 1.0%	8.0	25,350	770	98.0	0.09
18	CMHEC, 0.5%	22.0	25,070	285	98.9	0.09
19	CMHEC, 0.5%	25.8	23,500	200	99.1	0.08
20	CMHEC, 0.5%	29.8[a]	23,260	145	99.9	0.07
21	Cemad, 1.0%	22.4	25,150	2,890	88.5	0.97
22	Cemad, 1.0%	25.0	2,570	1,476	94.0	1.10
23	ET-181-6, 1.0%	51.5	25,450	535	97.9	0.41
24	ET-181-6, 1.0%	51.5	23,500	200	99.1	0.08
25	None	83.0[b]	26,510	1,155	95.6	1.36
26	None	78.0[b]	24,720	740	97.0	0.88
27	None	74[c]	23,260	165	99.3	

[a]No calcium lignosulfonate in this mix.

[b]These mixes contained no fluid loss additives.

[c]No fluid loss additive, calcium lignosulfonate, or bentonite; pressurizing gas leaked out of slurry before test was completed.

determining the amount of ^{90}Sr in the filtrate appeared to be the presence, or absence, of small solid particles which passed through the 325-mesh U. S. Standard Sieve Series screen (44-μ size) during the first few seconds of the test. The rapid reaction of ^{90}Sr with the small solid particles might be explained on the basis of the composition of portland cement. Portland cement is composed mainly of calcium silicates, which react with water to form hydrated calcium silicates. Since strontium and calcium have similar chemical behavior, ^{90}Sr rapidly entered into these reactions in common with calcium.

A few tests were made with actual ORNL waste. Table 5.10 gives the results of fluid loss tests with a mix identical to mix 23 of Table 5.6 except that it contained 0.5% CMHEC as the fluid loss additive. The results show that slightly more ^{137}Cs was removed from the actual waste than from the synthetic waste. The reason is believed to be the lower sodium content of the actual waste, because sodium competes for the exchange positions on the bentonite. The removal of ^{90}Sr is nearly the same (93%) as that measured in tests with synthetic waste. The overall reduction in gross gamma activity with the actual waste was 88.6%; most of the gamma activity in the filtrate was identified as ^{106}Ru. The relatively short half-life (1.0 year) of ^{106}Ru reduces the long-term hazard of this radionuclide. The very low content of ^{90}Sr in the actual waste results from neutralization of the waste with excess caustic, as noted earlier.

Table 5.10. Composition of ORNL Waste and of the Filtrate from Fluid Loss Test

Fluid loss was 30 cc

Radiochemical Analysis				Stable Chemical Analysis of Waste			
Radionuclide	Concentration in Waste (dis min^{-1} ml^{-1})	Analysis of Fluid Lost from Slurry (dis min^{-1} ml^{-1})	Activity Reduction (%)	Ion	Concentration (*N*)	Ion	Concentration (ppm)
^{90}Sr	6.34×10^{3}	440	93.1	Na^{+}	0.10	Fe	<1.0
^{137}Cs	1.44×10^{6}	5.55×10^{4}	96.2	OH^{-}	0.04	Cu	<1
^{106}Ru	1.84×10^{6}	4.04×10^{5}	78.0	NO_3^{-}	0.029	Mg	<10
^{144}Ce	6.54×10^{3}	180	97.2	CO_3^{2-}	<0.001	Ca	<1
^{60}Co	1.3×10^{3}	1.0×10^{3}	23.1	SO_4^{2-}	0.001	K	<15
^{95}Zr-Nb	780	206	73.6	SO_3^{2-}	0.0005		
Gross β^{a}	3.0×10^{3}	2.06×10^{4}	93.1	Cl^{-}	<0.001		
Gross γ^{a}	4.4×10^{5}	5.01×10^{5}	88.6	Al^{3+}	0.003		

[a]Counts min^{-1} ml^{-1}.

The slurry made with actual ORNL waste was allowed to set in 2-in. cube molds. After 7 days and 28 days of curing at 80°F, the 2-in. cubes were leached with tap water under constant stirring. The leaching results are plotted in Fig. 5.1. After 20 days of leaching, 5.7% of the activity was leached from the 7-day-cured grout, and gamma spectrum analysis revealed that ^{137}Cs was the predominant radionuclide in the leachate. Leaching tests of cube molds made with synthetic waste spiked with ^{137}Cs or ^{85}Sr and cured for 7 days and 28 days are also shown in Fig. 5.1. The grout made with synthetic waste leached slightly less ^{137}Cs than that made with actual ORNL waste. Lengthening the curing time of the grout improved retention of the radionuclides, as shown in Fig. 5.1; lengthening the curing time also increased the strength of the grout (Table 5.7). The higher ^{137}Cs leach from the seven-day-cured grout was probably due to the inability of the weaker grout to fix bentonite in the matrix.

The results obtained in phase I of this study were most encouraging. Mixes could be formulated with actual ORNL waste which would remain pumpable over 8 hr, set without phase separation, have low fluid loss properties, and retain most of the hazardous radionuclides in the solid phase.

MIX DEVELOPMENT – PHASE II

Several developments occurred during the early stages of mix development which suggested changes in emphasis and reevaluation of the program. First, as mentioned earlier, the incorporation of an evaporator in the Laboratory's waste management scheme meant that the concentration of the waste we hoped to dispose of would increase from 1X to 10X (Table 5.2). The molarity of the dissolved ions would be increased, and thus 1X waste mixes would have to be reevaluated in terms of their applicability to 10X waste. Second, reevaluation of early fracturing tests in the

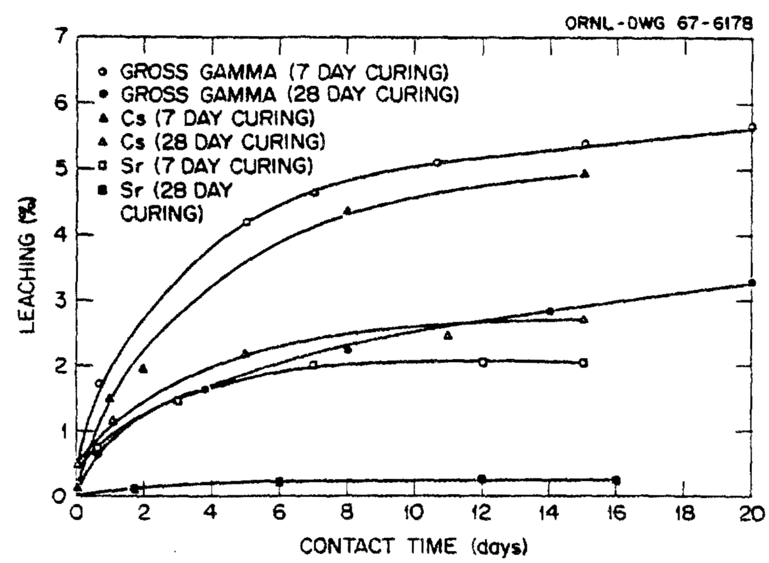

Fig. 5.1. Leaching of Radioactivity from Grouts Cured for 7 and 28 Days.

disposal formation indicated strongly that only minor fluid losses would occur during the time required for injection. It might be possible, therefore, to eliminate fluid loss additives from the mix. Since elimination of one material caused changes in slurry properties other than the one intended, this meant reevaluation of the mixes. Finally, preliminary estimates of the cost of disposal by hydraulic fracturing showed that the cost of mix ingredients would constitute a substantial part of the total cost.[3] Hence, reducing the cost of additives in mix formulations was imperative. The cost of the ingredients in mix 3 (Table 5.7), for example, is approximately 35 ¢/gal.

We expected that the molarity of all ions in 1X waste, including the sulfate ion, would increase when 1X waste was concentrated in the new evaporator. Because of the deleterious effects of sulfates on portland cement, we decided to specify the use of sulfate-resistant type II cement for mixes with 10X waste. Also, during the initial tests of various mixes, we found that the properties of the mixes varied from batch to batch of the cement obtained from the local supplier. The supplier explained that recent developments in the production of cement were in the direction of shorter setting times (i. e., producing cement which contained anhydrite instead of gypsum). For our work, however, longer setting times were desired, and type II cement with gypsum retarder, or the equivalent, was therefore specified so as to reduce the need for higher concentrations of an extender such as calcium lignosulfonate (CLS) or delta gluconolactone (DGL).

Testing of the three mixes shown in Table 5.7 with 10X waste solutions showed that the pumping times of mixes 1 and 2 were reduced to less than 2 hr. Mix 3, which contained carboxymethyl hydroxyethyl cellulose (CMHEC), showed more promise; when the fluid loss additive was omitted, the pumping time was approximately 4 hr and the consistency was about 20 poises. Deletion of the fluid loss additive lowered the cost of the ingredients approximately 40% (i. e., to about 15 to 20 ¢/gal), thus making cement the principal item of cost.

The compressive strength of seven-day-cured grout as a function of cement content is shown in Fig. 5.2. Also shown is the cement cost (1¢/lb) per gallon of waste for different cement concentrations. Obviously, if high-strength grout is desired, up to 15 lb of cement must be used per gallon of waste, and the mix will be expensive. If a grout strength of about 100 psi could be tolerated, a mix with 4 to 5 lb of cement per gallon could be used, and the mix cost would be lowered significantly.

Suspending Agents

When a slurry containing only 4 to 5 lb of cement per gallon of waste is allowed to stand without stirring, the cement powder settles toward the bottom, leaving clear liquid on the top (phase separation). To take up the excess liquid and to keep the solid phase in suspension, bentonite is generally added to such lean cement mixes. In the waste solutions to be injected, however, the concentration of dissolved ions is extremely high — in excess of 5 *M*. Under these conditions the bentonite flocculates and is ineffective as a suspending agent. Since attapulgite is known to be a more effective suspending agent in high-molarity salt solutions,[5] it was tried and found to be ef-

[5] R. E. Grim, *Applied Clay Mineralogy*, p. 287, McGraw-Hill, New York, 1962.

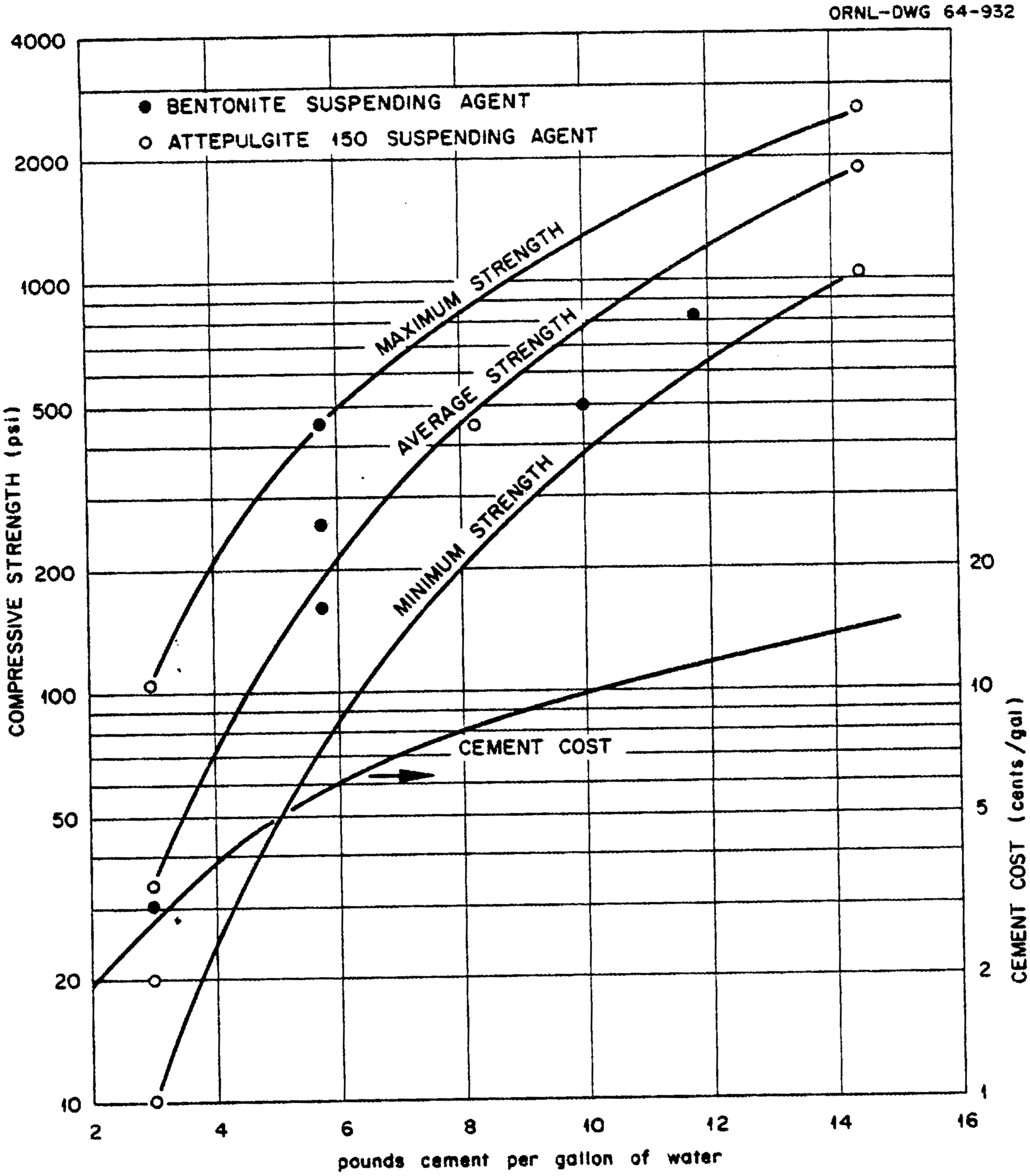

Fig. 5.2. Compressive Strength and Cement Cost vs Cement Concentration in Slurry.

fective and a good sorbent for the excess liquid. Several forms of attapulgite were tried. Only attapulgite 150 (Attagel 150) was effective; attapulgite RVM and attapulgite LVM were no more effective than bentonite.

The relative effectiveness of attapulgite 150 and bentonite in preventing phase separation can be seen in Fig. 5.3. The basic slurry contained 5 lb of cement per gallon of 10X waste; 10% of attapulgite and 10% bentonite (montmorillonite) by weight of cement were added to this basic slurry (Fig. 5.3*a* and *b*). Approximately 20% phase separation is seen in the bentonite-bearing slurry. Increasing the addition of bentonite to 15 and 20% by weight of cement did not reduce the phase separation.

Hence, in anticipation of having to deal with ORNL's evaporator concentrate containing dissolved salts and caustic exceeding 5 *M*, we selected attapulgite 150 for use as the suspender in subsequent mix formulations.

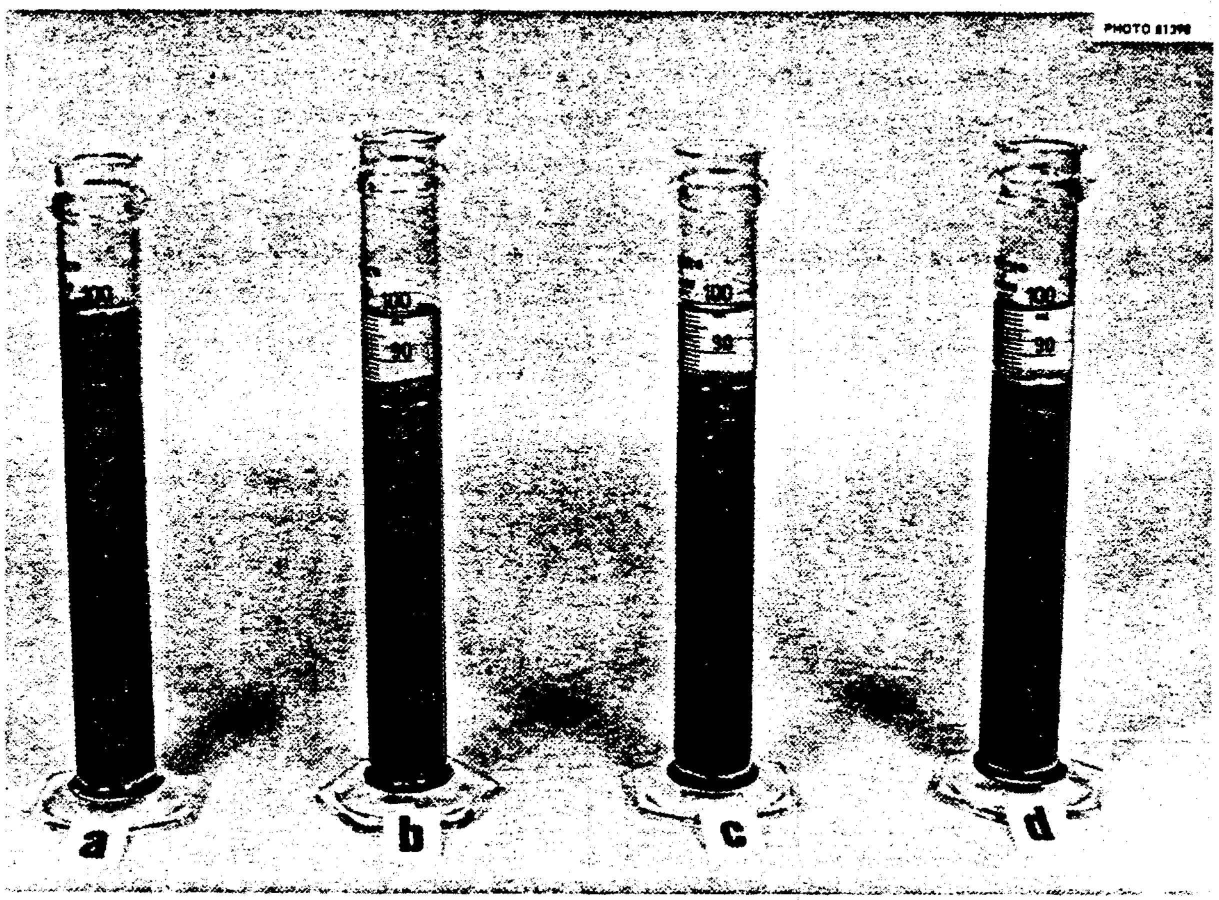

Fig. 5.3. Comparative Behavior of Mixes Containing Attapulgite (*a*) and Montmorillonite (*b*) as Suspenders. Increasing montmorillonite by 50% (*c*) and 100% (*d*) did not improve phase separation.

Low-Cement Mixes

To obtain compressive strengths of approximately 100 psi after seven days of curing at 80°F required about 4 to 5 lb of cement per gallon of waste, as shown in Fig. 5.2. Earlier tests had shown that varying the salt and caustic concentrations did not significantly change the compressive strength of grout cured at 80°F (Fig. 5.4). The cement content, therefore, was tentatively fixed at 4 to 5 lb per gallon of waste. As noted in the previous section, the suspender selected for our applications was attapulgite 150. Table 5.11 shows the properties of slurries and grout prepared with either 4 or 5 lb of type I or type II cement, with varying amounts of attapulgite 150 and with two different retarders. The results of these tests led to several conclusions regarding the selection of mix materials. When type I cement was used with 10X waste, the compressive strength decreased after 14 days; when type II cement was used, the strength developed gradually and decreased only slightly after 28 days. Since further wastes would contain the high salt contents, particularly sodium sulfate, type II cement was chosen because it is normally more resistant to sulfate deterioration.

None of the mixes in Table 5.11 satisfied the fluid loss requirements set initially. Mix 1 (Table 5.11) had a fluid loss of 138 cc; when bentonite was substituted for attapulgite, the fluid loss was 239 cc. When 0.8% CMHEC was used in place of 1.5% CLS, the attapulgite-containing slurry showed a loss of 82 cc and the bentonite-containing slurry had a loss of 47 cc. These results raised an interesting question: If CMHEC works well with bentonite, which is known to flocculate in the 10X waste, would attapulgite work equally well if it were in a flocculated state? To obtain an answer to this question, attapulgite LVM, which flocculates in 10X waste, was substituted for attapulgite 150. With 0.8% CMHEC as the fluid loss additive, fluid loss was 28 cc, which was lower than that observed with bentonite. These results suggested that CMHEC would be effective in flocculated clay systems. The requirement of no phase separation further suggested

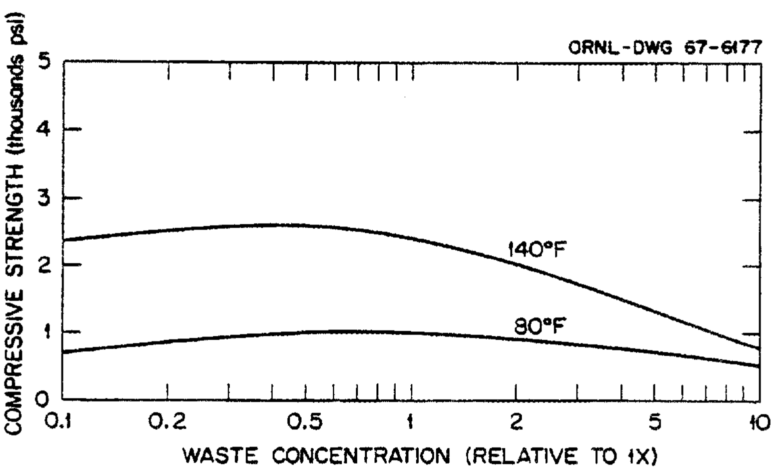

Fig. 5.4. Influence of Waste Concentration on the Compressive Strength of Grouts Cured at 80 and 140°F for 24 hr.

Table 5.11. Slurry Evaluation of Low-Cement Mixes with 10X Synthetic Waste

Values in parentheses represent data obtained on rechecking of certain slurries

N. D. = not determined

Slurry No.	Attapulgite 150 (lb/gal)	Retarder[a]	Viscosity (poises) at 20 min	Water Separation (cc/250 cc)	Fluid Loss (cc/30 min)	Thickening Time to 30 Poises,[b] 1000 ft, 89°F (hr:min)
			4 lb Type I Cement per Gallon of 10X Waste			
1	0.278	CLS, 1.5%	2	0.8	138	6:26
2	0.500	DGL, 0.3%	5	1.0	163	N. D.
3	0.600	DGL, 0.3%	8	0.8	145	N. D.
4	0.700	DGL, 0.3%	9	0.1	131	8:22
5	0.700	DGL, 0.4%	N. D.	N. D.	N. D.	11:17
6	0.700	CLS, 2.0%	N. D.	N. D.	N. D.	5.07
7	0.700	CLS, 2.5%	N. D.	N. D.	N. D.	6.08
			5 lb Type I Cement per Gallon of 10X Waste			
8	0.278	CLS, 1.5%	3	0	172	N. D.
9	0.347	CLS, 1.5%	4	0	134	4:01 (3:49)
10	0.347	CLS, 1.5%	1	0.4	164	4:09
11	0.347	CLS, 2.0%	N. D.	N. D.	N. D.	4:49
12	0.347	CLS, 2.5%	N. D.	N. D.	N. D.	5:48
13	0.347	DGL, 0.2%	1	3.4	208	5:57
14	0.347	DGL, 0.2%	N. D.	1.5	N. D.	6:11
15	0.347	DGL, 0.3%	2	2.9 (3.0)	211	9:36 (10:14)
16	0.500	DGL, 0.3%	5(5)	1.1 (1.0)	157 (160)	9:46 (9:30)
17	0.600	DGL, 0.3%	9	0.7	139	N. D.
18	0.700	DGL, 0.3%	12	0.2	124	N. D.
			5 lb Type II Cement per Gallon of 10X Waste			
19	0.500	DGL, 0.2%	8	0	146	7:18
20	0.500	DGL, 0.3%	3	0.8	158	11:20

Compressive Strength (psi) at 65°F and Indicated Curing Time

Slurry No.	2 days	3 days	4 days	7 days	10 days	14 days	28 days
2	90	135		260		345	175
9	45	85		125			70
14	130	200		360		365	190
15	95	180		320		355	210
16	130	220		360		370	325
19	85		175		275		255
20	35		170		250		235

[a]CLS = calcium lignosulfonate; DGL = delta gluconolactone.

[b]Thickening times are reported to 30 poises viscosity because low quantities of cement do not permit attainment of 70 poises.

the desirability of a highly dispersed system. For extremely low fluid loss, attapulgite LVM or bentonite with CMHEC, in addition to the attapulgite 150 (needed to suspend the cement), appeared to be the answer.

Several of the mixes shown in Table 5.11 met the requirement of 8 hr thickening time, particularly the mixes containing DGL (delta gluconolactone). Since these formulations were tested at ORNL before we had procured the Consistometer (an instrument used to measure apparent viscosity of slurries under controlled temperatures and pressures), Vicat tests were used to determine the thickening time. The time required to reach initial set, as indicated by penetration of the slurry by the Vicat needle, is a measurement of the thickening time. These data indicated that longer thickening times could be obtained with CLS and CMHEC if bentonite was used as the suspender; however, as mentioned earlier, the bentonite flocculated and the slurries set with about 20% phase separation. Sodium lignosulfonate (SLS) was not effective as a retarder, and the bulk density was high. These tests were important in bringing to light the problem of solid/liquid proportioning caused by air entrainment (low bulk density).

Defoaming Waste Solutions and Deaerating Slurries

In many of the tests conducted during development of mixes, it was noticed that the bulk density of the slurry was extremely low (Table 5.12). Also it was noted that foam collected on the slurry in the Waring Blendor. The cause of the low bulk density was obvious; numerous air bubbles could be seen in the slurry. Since the basis of control of solids to liquid proportioning in the plant is the relationship between the amount of solids in the mix to the slurry density, air entrainment in the slurry had to be prevented or at least minimized. Furthermore, air entrapment in the slurry would be expected to reduce the efficiency of the high-pressure injection pump and to cause excessive vibration of the high-pressure piping.

Two defoaming agents, tributyl phosphate (TBP) and silicone, were tested with a mix containing calcium lignosulfonate as retarder (Table 5.13). At the same concentration level, TBP was almost twice as effective as silicone; hence TBP was selected.

In comparing the effectiveness of TBP for deaerating mixes containing CLS, SLS, or DGL, it was found that DGL slurries approached "theoretical density" when the retarders were present in desired amounts. Sodium lignosulfonate (Polyfon H and F) reduced the air entrainment of slurries when substituted for CLS, but the slurry still contained appreciable air bubbles (Table 5.13). Not only did we select TBP as the defoaming agent, but the data in this table gave another reason for selecting DGL as the extender.

Since TBP is a liquid and is only slightly miscible in water, provisions were made to add 250 ppm of TBP in the waste feed line in the plant so that the TBP would be thoroughly mixed with the waste before it reached the jet mixer bowl at the bottom of the dry solids hopper.

Table 5.12. Slurry Properties of Lean Cement-Waste Mixes

Slurry No.	Cement/Waste (lb/gal)	Suspending Agent	Retarder[a]	Bulk Density (g/cc)	Vicat Initial Set[b] (hr)	Fluid Loss (cc/30 min)
1	4	Attapulgite 150, 6.6%	CMHEC, 0.5%		45	
2	4	Attapulgite 150, 6.6%		1.39	22	
3	4	Attapulgite 150, 6.6%	CMHEC, 0.8%	1.09	70	82
4	4	Attapulgite 150, 6.6%	CLS, 1.5%	0.96	70 (6:26)	104
5	4	Attapulgite 150, 6.6%	CLS, 0.75%	1.00	65	99
6	4	Bentonite, 6.6%	CMHEC, 0.8%		236	47
7	4	Bentonite, 6.6%	CLS, 1.5%			239
8	4	Bentonite, 6.6%	CLS, 0.75%		472	
9	5	Attapulgite 150, 6.9%	CLS, 1.5%	0.90	44 (4:00)	78
10	5	Attapulgite RVM, 6.9%	CLS, 1.5%			124
11	5	Attapulgite 150, 6.9%	SLS, 1.5%	1.33	<20	85
12	5	Attapulgite 150, 6.9%	SLS, 3.0%	1.25	17	90
13	5	Attapulgite 150, 6.9%	CFR-1, 0.2%	1.25	(5:57)	208
14	5	Attapulgite 150, 6.9%		1.60[c]		

[a]CMHEC = carboxymethyl hydroxyethyl cellulose; CLS = calcium lignosulfonate; SLS = sodium lignosulfonate; CFR-1 = delta gluconolactone.

[b]Figures in parentheses refer to Consistometer pumping time for 1000-ft schedule. A relationship between Consistometer readings and Vicat readings is given in runs 4 and 9, where 70- and 44-hr Vicat readings were found to be equivalent to 6:26 and 4:00 Consistometer readings respectively.

[c]Slurry prepared without foaming; bulk density is maximum attainable for this mix.

Radionuclide Retention by Low-Cement Mixes

During the course of developing mixes, several changes occurred which made it desirable to reinvestigate radionuclide retention by mixes. First, the waste solution used in tests was concentrated tenfold (10X), and this meant that ions competing for sites on the solids also increased tenfold. Second, the solids content was reduced from approximately 14 lb per gallon of waste to 4–5 lb/gal. Third, attapulgite was substituted for bentonite, which had been used in earlier tests. The results in Table 5.14 show the retention of ^{137}Cs and ^{85}Sr by the slurry almost immediately upon contact with 10X waste. Radiostrontium retention was excellent (98%); ^{137}Cs retention was unsatisfactory, probably due to the increased salt content. The addition of about 10% (by weight of cement) Grundite (illite clay) increased the ^{137}Cs retention to 85%.[6]

[6]T. Tamura and D. G. Jacobs, "Structural Implications in Cesium Sorption," *Health Phys.* 2, 395–98 (1960).

Table 5.13. Influence of Additives on the Density of Slurries

Basic slurry components:

10X synthetic waste — density = 10.90 lb/gal
5 lb Volunteer type I cement per gallon of 10X waste
0.347 lb attapulgite 150 per gallon of 10X waste

Slurry density (without foaming), 13.40 lb/gal

Retarder[a]	Other Additive[b]	Actual Slurry Density (lb/gal)		
		Immediately After Mixing[c]	1 min After Mixing[c]	20 min After Mixing[c]
CLS, 1.5%	None	8.80	9.22	9.02
CLS, 1.5%	TBP, 250 ppm	12.25	12.71	13.12
CLS, 1.5%	TBP, 500 ppm	12.26	12.65	13.21
CLS, 1.5%	Silicone, 250 ppm	10.88	11.28	11.88
Polyfon H, 1.5%	None	10.57	11.88	12.45
Polyfon F, 1.5%	None	11.62	12.34	12.94
Polyfon F, 1.5%	TBP, 250 ppm	12.65	12.81	13.03
DGL, 0.1%	None	10.76	11.22	13.38
DGL, 0.1%	TBP, 250 ppm	13.05	13.15	13.30
DGL, 0.2%	None	10.42	11.48	13.39
DGL, 0.2%	TBP, 250 ppm	13.24	13.24	13.38

[a]Polyfon (West Virginia Pulp and Paper Company), sodium lignosulfonates with varying degrees of sulfonation: H = 5.8% sodium sulfonate groups and F = 32.8% sodium sulfonate groups.

[b]Material added to 10X waste as potential defoamers. TBP = tributyl phosphate; silicone = UCC SAG 470 silicone antifoam emulsion.

[c]Mixing was done in a Waring Blendor. Times shown between density measurements were used for slow-speed stirring of the slurry. Approximately 1 min will be applicable to field mixing of the slurry in terms of possible air removal prior to displacement into the well.

Figure 5.5 shows the leaching of ^{137}Cs and ^{90}Sr from low-cement grouts (5 lb/gal) prepared with 10X waste and cured for 7 days. Radiocesium leach was higher (8.8%) than the 5% leach observed with the high-cement-content 1X waste grout. Radiostrontium leach reached a maximum of 2.47% after 20 days; this value may be compared with the 2.70% leach after 15 days of the grout prepared with 1X waste and 14 lb of cement per gallon. It appeared therefore that decreasing the cement and increasing the dissolved salt content of the slurry had little effect on the leaching behavior of the grout. It is believed that the ^{90}Sr leach was reduced in the 10X slurry because of the higher caustic content, which kept calcium hydroxide in the slurry as a solid and thereby reduced the leaching of ^{90}Sr. The increase in ^{137}Cs leach was not as high as expected, perhaps because of the better ^{137}Cs retention properties of attapulgite as compared with the bentonite used in the early leaching tests.

Table 5.14. ^{137}Cs and ^{90}Sr Activity in Filtrate from Fluid-Loss Tests of Low-Cement Mixes with 10X Waste

Slurry	Cement Content (lb/gal)	Attapulgite (%)	CLS Retarder (%)	Fluid Loss (cc/30 min)	Radionuclide	Activity Reduction (%)
1	4	6.6	1.5	88	^{137}Cs	41.3
					^{85}Sr	99.2
2	4	6.6	1.5	88	^{137}Cs	63.0[a]
3	5	6.9	1.5	79	^{85}Sr	99.2
4	5	6.9	1.5	78	^{137}Cs	31.0
5	5	6.9	1.5	78	^{137}Cs	85.6[b]
6	5	6.9	1.5	94	^{137}Cs	33.3
7	5	6.9	1.5	91	^{85}Sr	98.1

[a]Illite clay added; 5% by weight of cement.
[b]Illite clay added; 10% by weight of cement.

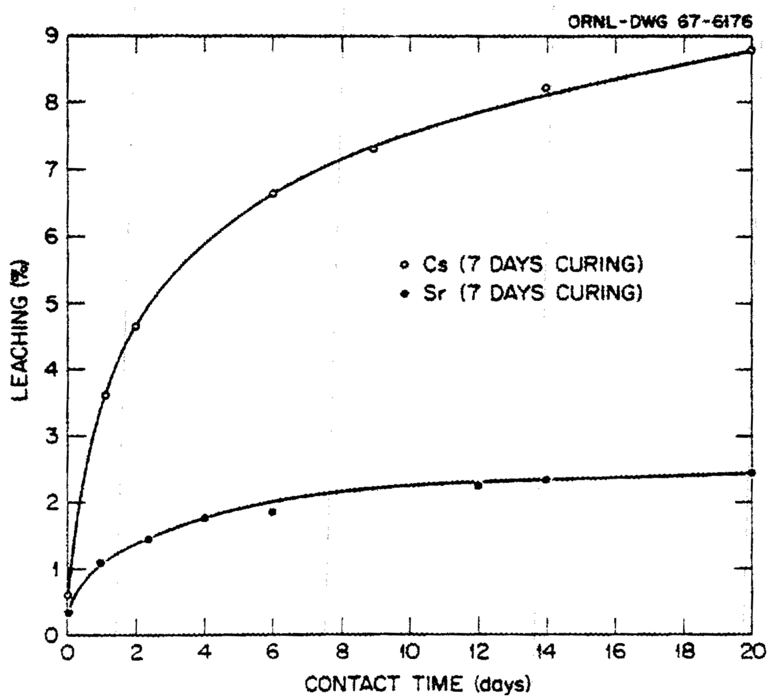

Fig. 5.5. Leaching of Radiocesium and Radiostrontium from Low-Cement Mix.

Additives to Improve Radionuclide Retention

At this stage of mix development, we had met the requirements originally set (Table 5.1), with the exception of fluid loss. The requirement dealing with maximum fluid loss was difficult to evaluate. However, information obtained during the course of the investigation suggested that we could relax from an upper limit of 60 cc. The observations which suggested this change included the following. In the second fracturing experiment, the injection well and the nearby observation well leaked fluid long after the slurry had set up, indicating that not all of the fluid had been incorporated in the set grout. If the disposal formation was somewhat permeable, the fluid would have permeated the formation and little, if any, would have leaked from the wells. In a later test, in the present well, following injection with water and then water plus fluid loss additive, the flowback results indicated that the fluid loss additive had little or no effect – further evidence that a fluid loss additive was not needed. Hence, it was decided to eliminate the fluid loss additive in future tests; if later injection experiments should reveal the need for this additive, it could then be incorporated. Moreover, even if liquids were to escape into the formation via fluid loss or phase separation (discussed later), such losses in themselves would not be seriously detrimental if the radionuclides remained in the solid grout. Efforts to enhance radionuclide retention in the solid phase were therefore intensified.

Table 5.15 lists the various formulations with the accompanying reductions in activity in the fluid phase following application of the fluid loss test. Fluid loss values, though higher than the requirements in the original specifications, range from 82 to 280 cc; these values may be compared with 600 cc for neat cement and water. The results show that illite was beneficial for ^{137}Cs retention. Though pozzolan (Kingston fly ash) improved ^{90}Sr retention, it should be mentioned that the primary reason for the addition of pozzolan was to reduce the mix cost (as a substitute for the more expensive cement). Since ^{137}Cs is the more abundant radionuclide in ORNL's waste and since the earlier leaching tests (Figs. 5.1 and 5.5) showed that ^{137}Cs could be leached from the various grouts, the use of an illite additive for ^{137}Cs retention was strongly indicated.

Activity reductions during fluid loss tests are representative of radionuclide losses from the liquid phase of a slurry. The loss or leaching of radionuclides from set grout is a separate problem. Grouts were prepared in the laboratory in 2-in. cube molds and leached with water. Most of the tests were performed with synthetic waste spiked with either ^{137}Cs or ^{85}Sr; several tests were run with actual ORNL waste solutions in which ^{137}Cs and ^{106}Ru were the predominant radionuclides. Comparison of grouts with and without illite showed reduced leaching of ^{137}Cs by a factor of about 4 (Table 5.16) when illite was present. The choice of illite was made on the basis of our earlier work, which had identified and demonstrated that illite was a highly selective sorbent for radiocesium.[7] It may be mentioned that bentonite can be made to selectively sorb

[7] T. Tamura and D. G. Jacobs, "Improving Cesium Selectivity of Bentonites by Heat Treatment," *Health Phys.* 5, 149–54 (1961).

Table 5.15. Reduction of Radionuclide Activity in Filtrate from Fluid Loss Tests

Slurry	Cement Content (lb/gal)	Attapulgite (%)	DGL[a] (%)	Waste Type	Fluid Loss (cc/30 min)	Radionuclide	Activity Reduction (%)	Comments
1	14	0	0	10X	121	^{137}Cs	10.65	Flash set
2	14	0	0	10X	N. D.[b]	^{137}Cs	66.00	6% bentonite, flash set
3	14	2	0.15	10X	137	^{137}Cs	58.07	
4	14	2	0.15	10X	135	^{90}Sr	97.27	
5	10	4.6	0.10	1X	N. D.	^{137}Cs	92.52	
6	10	4.6	0.10	1X	N. D.	^{137}Cs	98.48	5% illite
7	10	4.6	0.10	1X	178	^{90}Sr	80.87	5% illite
8	10	4.6	0.10	1X	180	^{90}Sr	88.70	30% pozzolan, 5% illite (10 lb/gal)
9	0	4.6	0.10	1X	82	^{90}Sr	96.80	100% pozzolan (10 lb/gal) replaced portland cement
10	7	10	0.30	1X	231	^{90}Sr	81.74	7% illite
11	7	10	0.30	1X	196	^{90}Sr	86.23	30% pozzolan, 7% illite
12	7	10	0.30	1X	135	^{137}Cs	97.10	7% illite
13	7	8	0.3	1X		^{137}Cs	98.52	7% illite
14	6	12	0.3	3X	152	^{90}Sr	95.08 (97.53)	25% pozzolan, 12% illite
15	6	12	0.3	3X	160	^{90}Sr	92.70	12% illite
16	4.5	16	0.3	3X	188	^{90}Sr	95.74	58% pozzolan, 10% illite
17	4.5	16	0.15	3X	177	^{90}Sr	96.55	58% pozzolan, 10% illite
18	4.5	16	0.05	3X	219	^{90}Sr	94.06	58% pozzolan, 10% illite
19	4.5	16	0.05	3X	279	^{90}Sr	93.46	58% pozzolan
20	4.5	16	0.05	3X	280	^{137}Cs	88.88	58% pozzolan
21	4.5	16	0.05	3X	216	^{137}Cs	96.68	58% pozzolan, 10% illite
22	4.5	16	0.05	3X	181	^{137}Cs	97.66	58% pozzolan, 20% illite

[a] Delta gluconolactone.

[b] N. D. = not determined.

Table 5.16. Percentage of Radioactivity Leached from Grouts Prepared with ORNL Waste and Spiked Synthetic Waste

Grouts cured for seven days and leached with tap water for 500 hr

Grout No.	Cement Content (lb/gal)	Waste Type	Illite Clay Additive (lb/gal)	Percent Leached from Grouts Prepared with – Synthetic Waste Tagged with – ^{85}Sr	^{137}Cs	ORNL Waste[a]
1	5	10X	0	2.47	8.81	
2	5	10X	0.40	2.69	1.98	
3	6½	1X	0	8.85	8.62	
4	6½	1X	0.45	5.80	3.70	0.50
5	7	0.1X	0	18.9	16.4	6.80
6	7	0.1X	0.45	23.0	4.73	2.23
7	10	1X	0	3.81	7.86	12.0
8	10	1X	0.50	5.07	1.89	
9	14	10X	0	0.82	5.74	7.59
10	14	10X	0.28	2.26	1.04	
11	6½[b]	1X	0	3.45		
12	6½[b]	1X	0.50	3.70		
13	6½[c]	3X	0.50	0.80		
14	6½[d]	3X	0.50	0.10		

[a]Radionuclides in ORNL waste were primarily ^{137}Cs and ^{106}Ru.
[b]The cement was substituted with 58% pozzolan (Kingston fly ash).
[c]Grout was cured for 28 days.
[d]Grout was cured for 28 days and cement was substituted with 25% pozzolan.

radiocesium and substitute for illite.[8] The treatment, which is simple and effective, consists in heating the bentonite to 500–600°C; the resultant product is as effective as illite. Other sorbents for radiocesium and radiostrontium have been investigated in this laboratory and reported.[8]

Waste composition, curing time, and the amount and kind of solids in the mix had a marked influence on the leaching of ^{85}Sr; the lowest leaching was observed in the grouts prepared with the highest cement content (14 lb/gal). Data were presented earlier for 14 lb/gal cement in 1X waste

[8]T. Tamura, "Development and Applications of Minerals in Radioactive Waste Disposal," *Proc. Intern. Clay Conf.* 1, 425–39 (1966).

(Fig. 5.1) which when cured for 28 days leached approximately 0.25% and when cured for 7 days leached 2.10%. The high leach of ^{85}Sr from grouts 5 and 6 was probably due to the low hydroxide content of the waste, which, when leached, would allow more calcium hydroxide to dissolve in accordance with the law of mass action. It cannot be due to the cement, since grouts prepared with lower cement additions in 1X, 3X, and 10X wastes leached less radiostrontium. In comparing grouts 3 and 4 with 11 and 12, it is seen that the substitution of pozzolan (Kingston fly ash) for cement reduced the ^{85}Sr leach. Further evidence of this reduction is shown in the results with grouts 13 and 14. From these data in Table 5.15, one can conclude that the reduced leaching of radiostrontium from the final grout is favored by high cement content, by substitution of cement with pozzolan, by long curing time, and by high caustic content.

One of the reasons for substituting pozzolan for cement in the waste mix was revealed by the analysis of grout leachates. It was found that a significant amount of calcium was leached in addition to the salts normally present in the waste. Presumably, this calcium came from soluble compounds formed in the cement as it set. The analytical data confirmed that the amount of radiostrontium leached was directly proportional to the amount of calcium dissolved from the grout (Fig. 5.6). It was reasoned, therefore, that reducing the soluble or leachable calcium from the grout would reduce the amount of radiostrontium leached from the grout. One way to reduce the soluble calcium in concrete is by partial substitution of pozzolanic material for portland cement. Pozzolanic materials are highly siliceous and aluminous materials which, by themselves, would not set when mixed with water or waste low in calcium. With the addition of pozzolanic material, calcium hydroxide in the cement, which contributes little or nothing to the strength of set cement, would be decreased and a lime-pozzolanic product would be formed.[9]

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[9]F. M. Lea, *The Chemistry of Cement and Concrete*, p. 379, Edward Arnold Ltd., London, 1956.

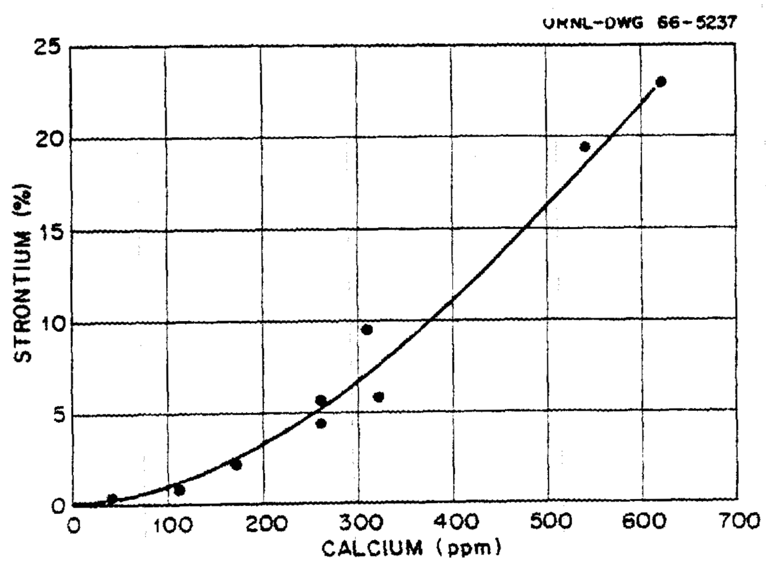

Fig. 5.6. Leaching of Radiostrontium as a Function of Calcium Concentration in the Leachate.

Fly ash from the nearby Kingston steam plant, a source of cheap pozzolanic material, was substituted for a portion of cement in the mix, and the leaching properties of the resultant grout were investigated. Tests showed that Kingston fly ash did indeed reduce the free lime content as well as the soluble calcium. Figure 5.7 shows the reduction in free lime and calcium as a function of the amount of fly ash added. Further tests with tracers confirmed the belief that the partial substitution of fly ash for cement would reduce the leachability of radiostrontium from the set grout. In a mix containing 2.0 lb of cement and 2.5 lb of fly ash per gallon of 1X waste, the radiostrontium content in the leachate was 2.50%; this value may be compared with 5.80% leaching from the mix containing 6.5 lb of cement.

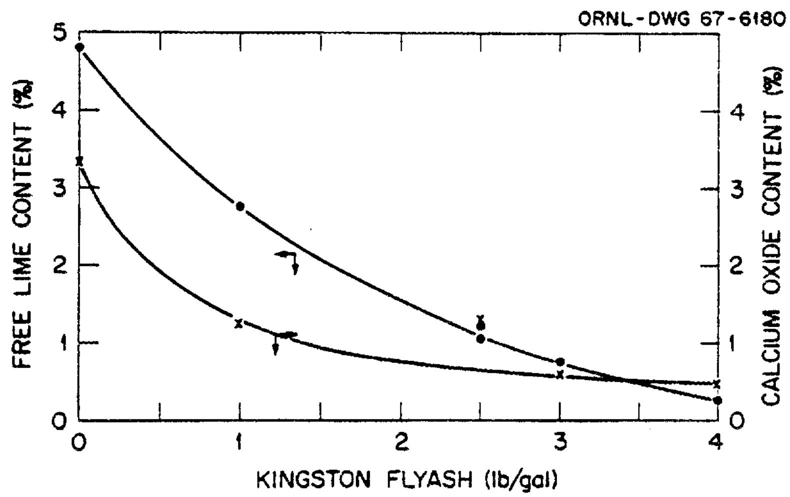

Fig. 5.7. Free Lime and Calcium Oxide Concentration as a Function of Pozzolan Content in Grouts. Cement plus pozzolan content equal 4.5 lb/gal.

During the mix development program, it was first necessary to provide mixes which would meet the engineering specifications. The additional additives (i.e., illite for radiocesium retention and fly ash for radiostrontium retention) were not used in the initial field experiments. Illite was added to the mix used in the fifth experimental injection and subsequent injections, and Kingston fly ash was used only in the sixth and seventh injections. The overall performance of these mixes will be described later in this report.

MODIFYING SLURRY PREPARATION IN THE LABORATORY

In laboratory tests of mix formulations prior to an injection in the field, the procedure for preparing slurries consisted in (1) stirring preblended solids and the waste solution in a Waring Blendor for 15 sec at approximately 4000 rpm or more (to simulate conditions in the jet mixer of the shale fracturing plant) and (2) operating the Blendor at about 10,000 rpm or more for 35 sec (to simulate conditions in the high-pressure lines to the wellhead and in the injection well during pumping). This is the standard procedure used in the petroleum industry for testing oil-well cement slurries.[2]

As the mix development program progressed, we observed that phase separation was sensitive to the shear stresses applied to the slurries, particularly in mixes low in cement and high in attapulgite. In such mixes, phase separation increased with decreasing shear. Thus, since mix formulations of low solids content with no phase separation were the desired goal, it became a matter of considerable importance to make certain that shear induced in the Waring Blendor was essentially the same as that induced by mixing and pumping equipment in the shale fracturing plant.

For the laboratory tests of mixes used in the first six experimental injections, the Waring Blendor was used for the time intervals specified above at 5200 and 10,560 rpm respectively. In injection 6, however, samples of slurry taken immediately after the jet mixer in the shale fracturing plant were brought back to the laboratory, restirred in the Waring Blendor at 10,560 rpm, and placed in 100-cc graduates for measurements of phase separation. It was found that the bulk density of the plant-mixed slurry was 10% below the desired minimum solids, and its phase separation measured approximately 30%. Tests of the same formulation, based on bulk density, prepared in the laboratory showed only 10% phase separation. The difference of 20% was ascribed to lower shear imparted by the jet mixer in the shale fracturing plant. To simulate the shear applied in the plant more closely, the formulation of the mix for the next injection (injection 7) was based on the slurry properties determined after mixing and stirring at 4000 rpm for 50 sec. With higher speeds of the Waring Blendor, less solids were required to prevent phase separation. The acceptability of using a lower shear to formulate mixes depended on the behavior of the field slurry and the bleedback from the formation after the slurry had set. Subsequent field tests supported the choice of the lower speed and thereby lower shear, as evidenced by the pumpable nature of the slurry and the reduced bleedback. More work is required to establish more reliable laboratory tests for field application and to establish applicability of field observations to laboratory behavior. However, until the work is completed, formulations are being based on using the Waring Blendor at speeds of 4000 rpm.

PHASE SEPARATION

It then became necessary to reevaluate the properties of mixes of low solids content whose slurries had been subjected to different shear stresses. It was found that radionuclide retention and thickening times were not sensitive to the shear stresses applied to the slurry; the initial consistency was higher with higher shear, but the final thickening time (measured in the Consistometer) was the same. Phase separation, however, was found to be highly sensitive to the shear. In addition, phase separation was sensitive to composition of the waste and of the solids blend.

Phase separation as a function of waste concentration is shown in Fig. 5.8. Note that the maximum in separation occurred with 3X waste; this suggested that any formulation with 3X waste showing no phase separation would be applicable to other waste concentrates with minor modifications. This might not apply to slurries formed with water. Water slurries are important in this connection because the actual disposal operation starts with water slurries (to check the operation of pumping and mixing equipment) and ends with water slurries (to clean the system and thereby reduce contamination in the high-pressure piping and in the injection well).

Two ingredients in the solids blend were found to affect phase separation. As expected, the amount of attapulgite had a strong influence on phase separation. This is shown in Fig. 5.9. The higher the content of attapulgite, the lower the phase separation; however, the higher the attapulgite content, the more viscous the slurry. In addition, DGL exerted a strong influence on phase separation. With increasing amounts of DGL (normally used to increase thickening time), the phase separation increases (Fig. 5.10). DGL also reduces the viscosity of the slurry; hence, when attapulgite content is high, higher amounts of DGL are used to reduce the viscosity.

In Fig. 5.11, the minimum blend necessary to prevent phase separation in waste concentrations up to 3X is plotted. Curves *A* and *B* represent two different formulations. In case *A*, the DGL content was higher, and the thickening time for the 1000-ft squeeze schedule was 17 hr. In the mix with lower solids, *B*, the thickening time was approximately 7 hr for the same squeeze schedule (3300 psi and 89°F). Acceptance of this formulation was based on the fact that the formation temperature is about 65°F, and we had found that as the temperature decreased, the thickening time increased. Application of formulation *B* was not attempted until after the series of experimental injections was completed and disposal by hydraulic fracturing was adopted for routine use at ORNL.

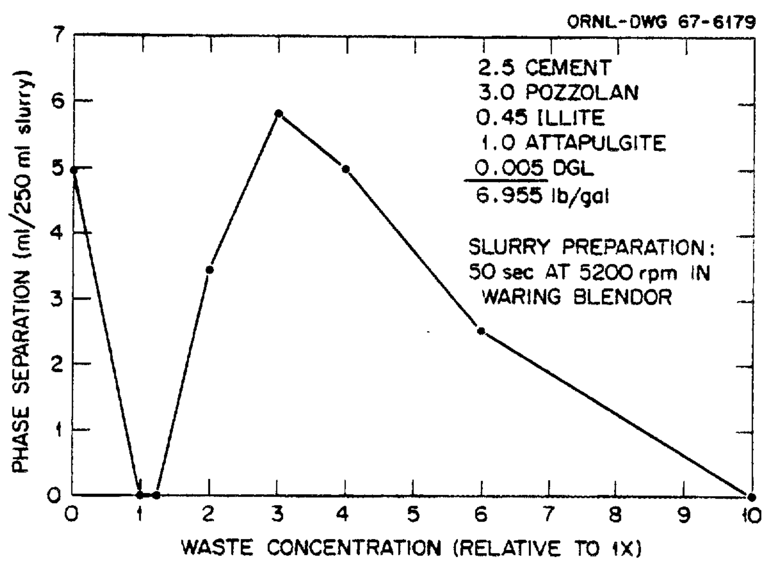

Fig. 5.8. Influence of Waste Concentration on Phase Separation.

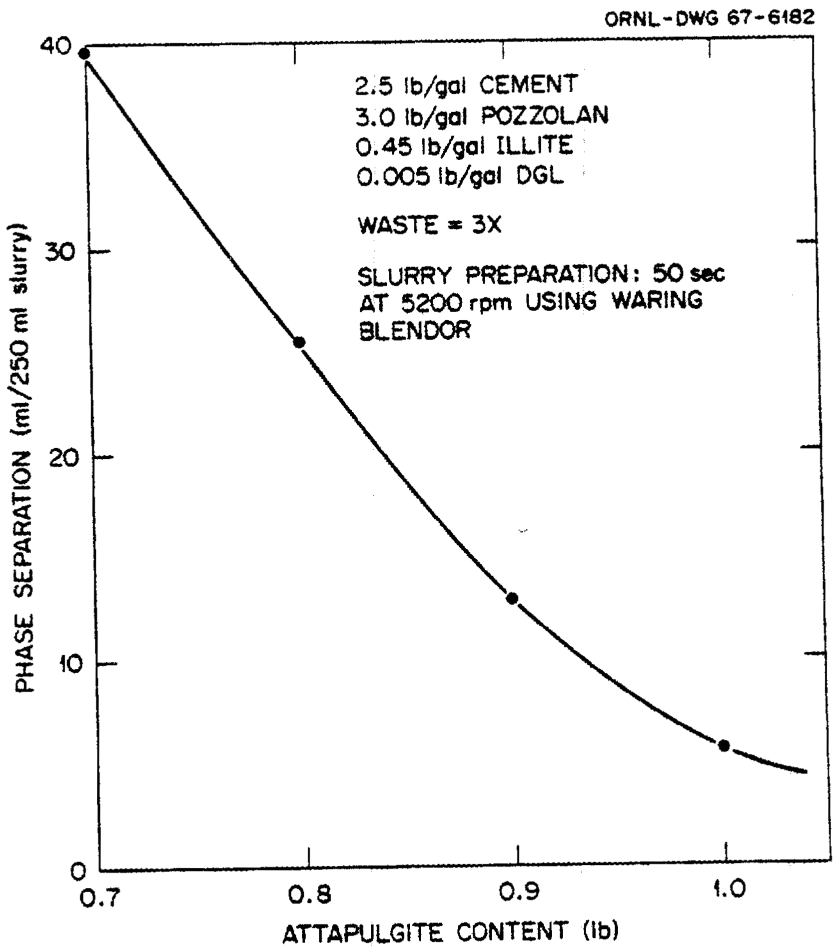

Fig. 5.9. Influence of Attapulgite Content on Phase Separation.

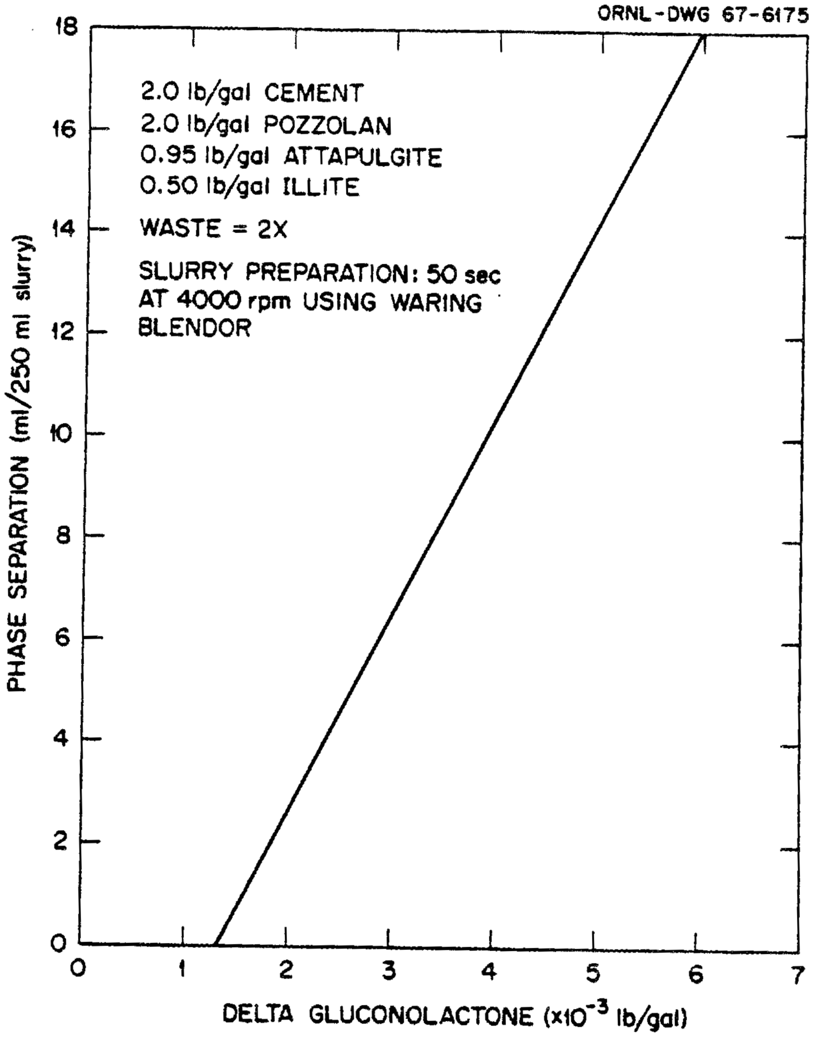

Fig. 5.10. Influence of a Retarder on Phase Separation.

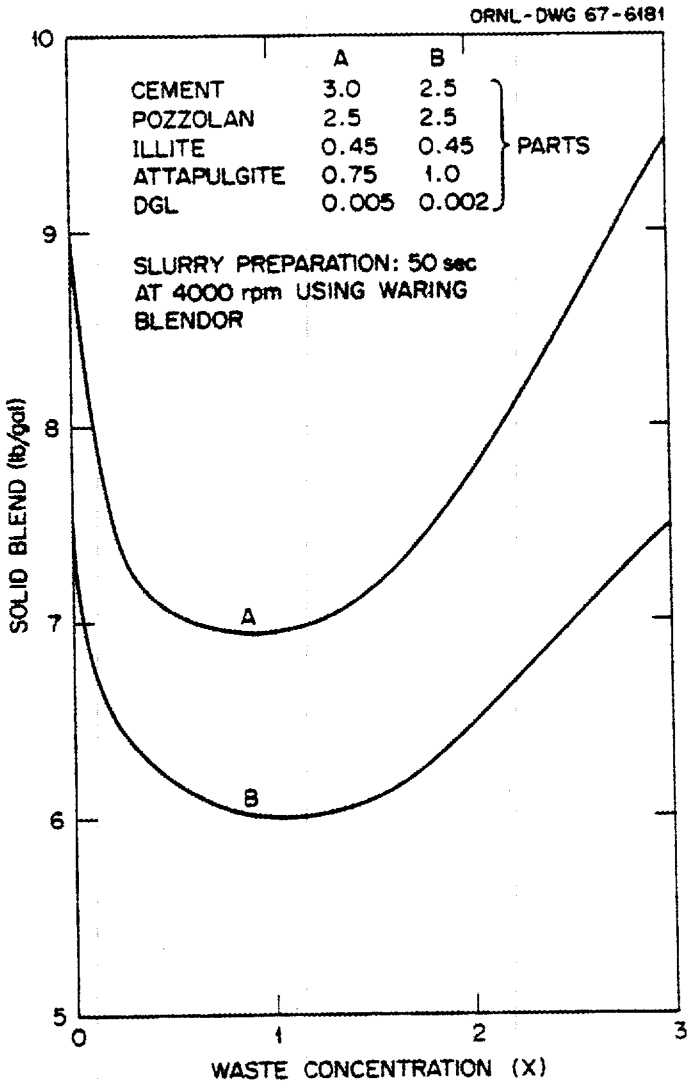

Fig. 5.11. Minimum Amount of Solid Blend Required to Prevent Phase Separation for Two Formulations.

MIX FORMULATION PROCEDURE

The following is the recommended laboratory procedure for formulating mixes of ORNL-type waste for disposal by hydraulic fracturing:

1. Sample and analyze the waste to be injected.
2. Prepare solids blend containing the following materials:

Portland cement type II, gypsum retarded or equivalent	2.5 parts
Pozzolan as desired and as available	2.5 parts
Attapulgite gelling clay	1.0 part
Illite	0.5 part
Delta gluconolactone	0.002 part

3. Prepare slurry using 550 cc of waste in 1-qt-size Waring Blendor. If waste approaches ORNL waste type (Table 5.2), solids addition will depend on waste composition as shown in Fig. 5.10. Add solids, using 15 sec to pour into Blendor and 35 sec of additional stirring. Blendor should be calibrated to rotate at 4000 rpm at no load.
4. Pour slurry into 250-ml graduate to estimate phase separation.
5. After 2 to 4 hr, determine phase separation. Increase or decrease proportion of solids, depending on phase separation. If no phase separation occurs, decrease solids to obtain minimum solids content necessary to prevent phase separation. Generally 5 to 10% change in solids is sufficient to obtain slurry with no phase separation if waste composition is similar to ORNL's waste.
6. Increase addition of solids by 10% over that amount which yielded no phase separation, and mix as in step 3. (The increase over the minimum amount is suggested to allow ±10% in the control of solids/liquid proportioning.) Determine thickening time of the slurry in Consistometer using appropriate temperature and pressures. Use API squeeze schedule, depending on the depth of the injection well. For a 1000-ft well, the temperature is 89°F and the pressure is 3300 psi (temperature changed later to 65°F).
7. Increase or decrease delta gluconolactone (DGL) content to obtain desired thickening time; redetermine phase separation if DGL content is changed. Desired thickening time depends on the volume of waste to be disposed and the rate of disposal. Equipment at ORNL is capable of pumping approximately 15,000 gph and has storage capacity of approximately 100,000 gal.
8. Prepare slurry using water and the solids blend, and determine as above for proper ratio to prevent phase separation. Water slurry is needed to start and to end all disposal injections.

SYNOPSIS

Laboratory studies have shown that ORNL-type waste is compatible with cement-base solids to provide pumpable slurries for disposal by hydraulic fracturing. The slurry requires a retarder such as delta gluconolactone to provide thickening times in excess of 3 hr. If the cement content is to be kept to a minimum, a suspender is required; attapulgite gelling clay serves this purpose for wastes of high sodium and caustic content. Bentonite is not effective as a suspender in wastes with high salt content. To improve radiocesium retention in the grout, illite clay should be used.

Pozzolanic material improves radiostrontium retention in grouts of low cement content and, in addition, reduces the cost of the mix, depending on the location of the source of pozzolan.

Further work is needed to develop laboratory testing procedures that will more closely simulate the mixing and pumping operations in the shale fracturing plant. Differences in shear stresses imparted in the Waring Blendor and in the field equipment may result in wastage of solids by over-addition. Estimated cost of the low-cement mixes is 6¢/gal based on cement cost of 1.0¢/lb; pozzolan, 0.3¢/lb; illite, 2.35¢/lb; attapulgite, 1.55¢/lb; and delta gluconolactone, 50¢/lb.

6. Design and Construction

DESIGN PARAMETERS

The hydraulic fracturing plant is situated about a mile from ORNL in neighboring Melton Valley. The site was chosen because the subsurface geology of this area was known to a depth of 3263 ft (see Chap. 2), a waste transfer line from the Laboratory was nearby, and the site was remote enough from the main Laboratory area so that any leakage of waste solution that might occur would be much less serious than a similar leak in the Laboratory area.

The surface operations of the hydraulic fracturing plant are basically similar to those of a well grouting job – an operation performed daily by service companies in the petroleum industry. In these operations a cement grout is mixed and pumped down a well and out into the surrounding formations by one or more pumper trucks – trucks carrying large positive displacement pumps. A single pump is typically capable of pumping cement grout over a range of flow rates and pressures from 700 gpm at 1000 psi to 105 gpm at 6000 psi.[1] Since the expected injection pressure for the hydraulic fracturing experiments (about 2000 psi) falls comfortably within the operating range of these pumps, they were a natural choice for the job. It was not feasible to rent the injection pump because the radioactive waste solutions to be injected during the hydraulic fracturing experiments would contaminate the pump too badly to permit its release. For this reason, the injection pump would have to be bought; and, since these pumps are quite expensive, there was considerable incentive to use as few as possible. Ultimately it was decided to buy one pump unit (pump, gear train, and diesel) for the injections and, in case the main pump should fail during an injection, have a pumper truck standing by that could pump water and cement slurry through the system to clear the well for future use. Since the pumper truck would handle only water, sand, and cement, it would not become contaminated and thus could be rented.

Three waste storage tanks with a total operating capacity of 40,000 gal were installed at the site of the shale fracturing plant. At the probable injection rate of 200 gpm the time required for each injection was thus fixed at a little over 3 hr. The rate at which waste solution can be pumped to the site (25 gpm) is too slow for waste transfer during an injection to be useful for increasing the volume to be injected. Since it was desirable to keep the waste-cement grout in a fluid state for the entire injection period, special additives were used to delay the setting time of the cement (see Chap. 5).

[1] Technical Data Sheet, Halliburton Co., Duncan, Okla.

The parameters of the hydraulic fracturing experiments – a semiremote location, a 1000-ft injection depth, a 200-gpm injection rate, and 40,000-gal batches – were fixed by the considerations given above. In some of the later injections, it was found possible to substantially increase the size of the injection batch; otherwise, these parameters were essentially constant throughout the experimental injection program.

Early in the program a working arrangement was initiated with the Halliburton Company, a company with long experience in the techniques of fracturing and underground grouting. They furnished consultant services on mix chemistry and process design, sold the high-pressure injection pump and much other special equipment to ORNL, and provided equipment operators and technical assistance during the experimental injections.

EQUIPMENT DESCRIPTION AND OPERATING PROCEDURE (AS OF 1965)

Two main types of wells were used in the hydraulic fracturing experiments: the injection well for the injection of the waste and an observation well for the determination of the depth of the grout sheet. The observation well is a prototype for the more numerous wells of this type that would be constructed near an operating plant. A sketch of these wells is shown in Fig. 6.1. Construction details of the injection well are shown in Figs. 6.2 and 6.3.

All waste injections were made through slots cut in the casing and surrounding cement of the injection well. As the injection proceeded and the grout sheet spread out from the injection well, it sometimes intersected the cemented casing of the observation well. A gamma-sensitive probe then lowered into the observation well detected the presence of the grout sheet, thereby establishing the depth of the grout sheet at that point.

Both wells are 1050 ft deep, and both casings are cemented to the well hole for their entire length. The bottom 350 ft of the observation well casing is cemented with a special low-strength cement. The main casing of the injection well is $5\frac{1}{2}$ in. OD, and the main casing of the observation well is $2\frac{7}{8}$ in. OD.

The equipment used for the injection of each batch of waste consists of a waste transfer pump and spare, four bins to store the cement and other solid constituents of the mix, a jet mixer, a surge tank, a high-pressure injection pump, a standby injection pump and mixer, and assorted valving and special equipment. The arrangement of this equipment is shown in Fig. 6.4. The mixer, surge tank, injection pump, and wellhead valving are installed in cells to reduce the radiation exposure of the operators and limit the area that would become contaminated in the event of a leak in the equipment or piping (Fig. 6.5). The cells are made of a 12-in. thickness of concrete block and are roofed with sheet metal. All necessary control operations are carried out from outside the cells during an injection. An overall view of the cells and the solids handling equipment is shown in Fig. 6.6. Shown are the bulk storage bins, the wellhead cell, the injection pump (to the right of the wellhead cell), the water storage tank (beyond the change house), and standby injection pump (far right). The valve handles that can be seen protruding from the wall of the wellhead cell are part of the high-pressure valve rack.

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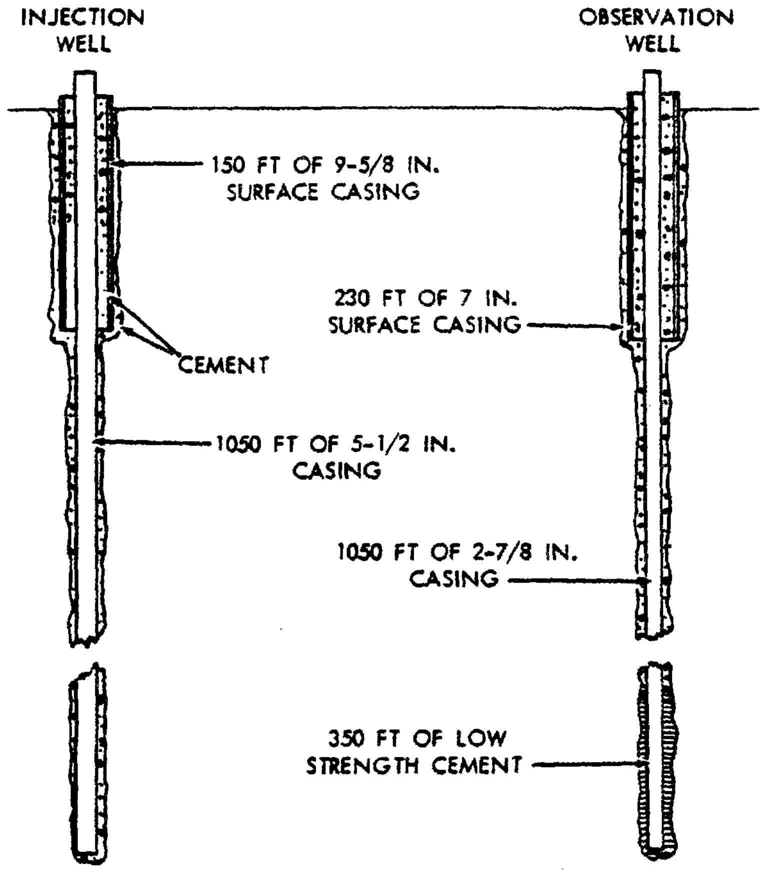

Fig. 6.1. Sketch of Wells for Fracturing Experiments.

The injection pump is shown in Figs. 6.7 and 6.8. It is a Halliburton HT-400 triplex positive displacement pump mounted on a skid with a ten-speed transmission and a VT-12 Cummins diesel engine. During an injection the splash shield on the pump is joined to the wall of the cell, thereby isolating the head of the pump inside the pump cell.

A view of the top of the mixer cell is shown in Fig. 6.9. The air slides that carry cement from the bulk storage bins feed into the top of the mixer hopper; the 4-in. line going up and to the right from the hopper vents the hopper to one of the bulk storage tanks. Slightly to the left of the mixer hopper is the top of the surge tank; the boxlike structure on top of the surge tank is a housing for a mirror so arranged that the interior of the tanks can be viewed from the operating platform without exposure to radiation.

A view of the equipment used for blending the solids prior to an injection is shown in Fig. 6.10. In the foreground is a "bazooka" – a screw conveyer for charging solids to the blending tanks in

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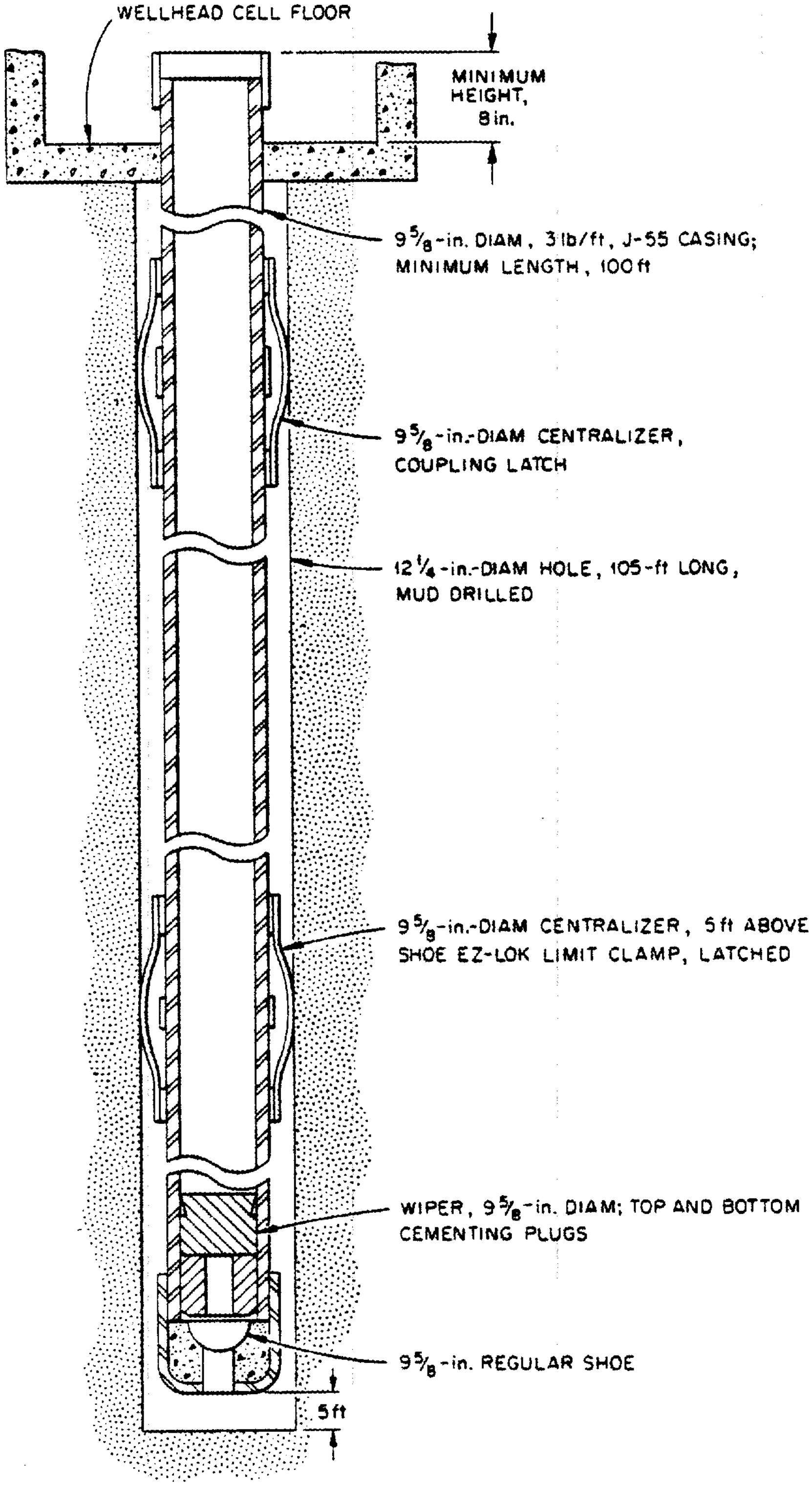

Fig. 6.2. Injection Well Construction – Surface Casing.

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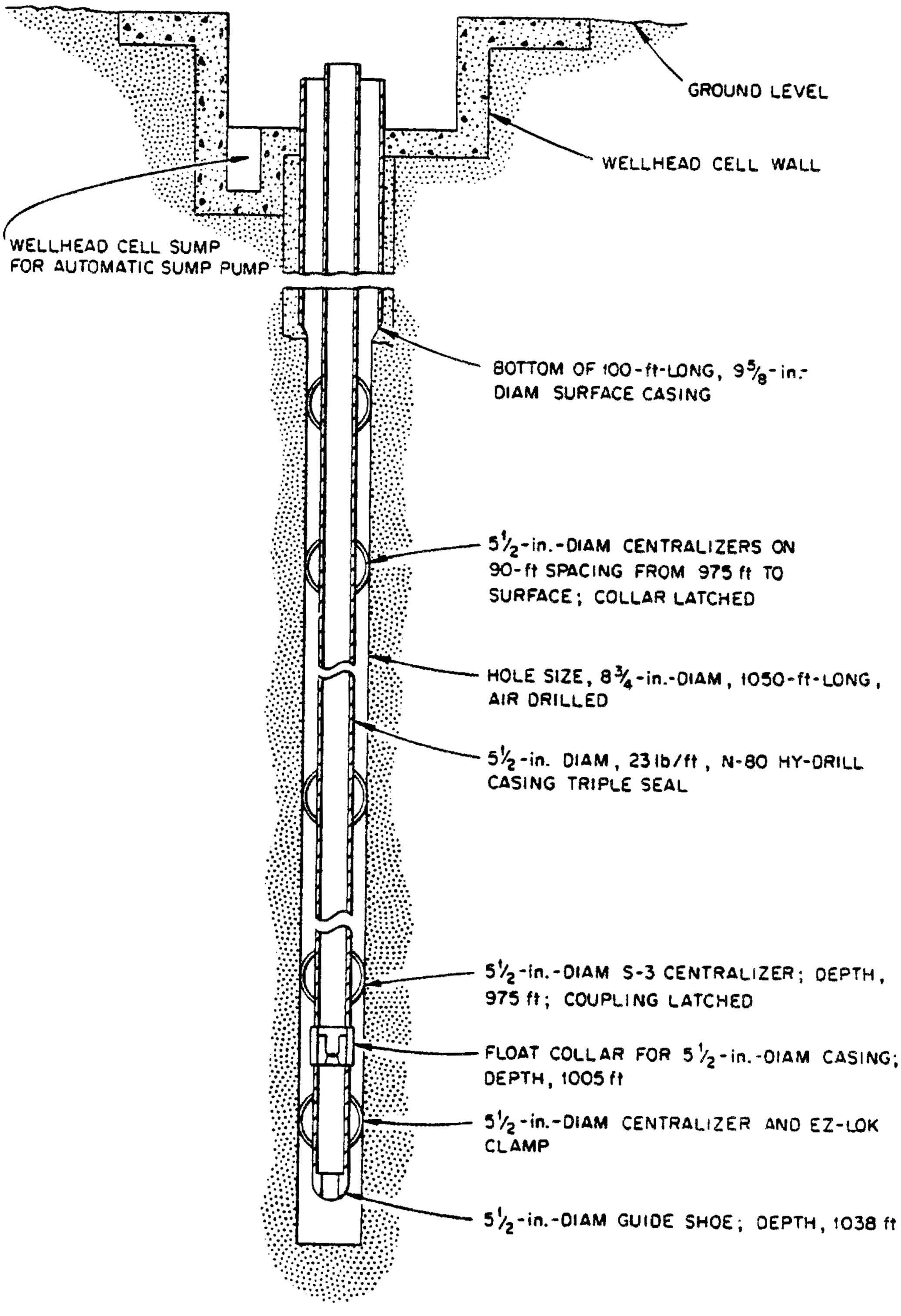

Fig. 6.3. Injection Well Construction – Well Completion.

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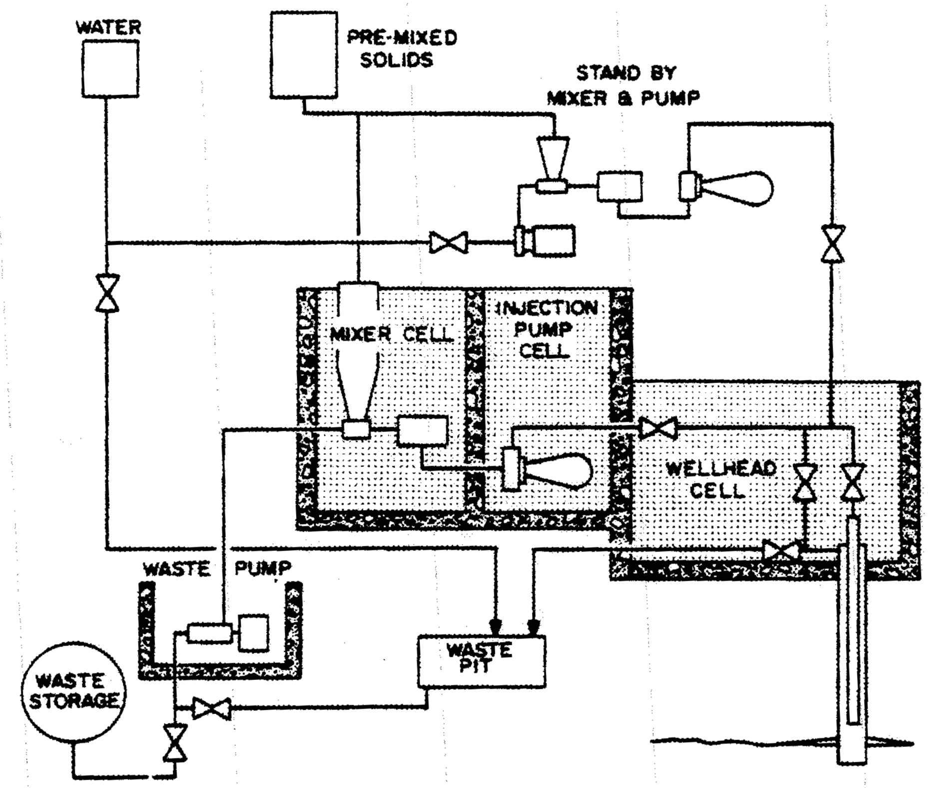

Fig. 6.4. Schematic Flow Diagram of the Hydraulic Fracturing Plant.

the background. The solids are blended by blowing them back and forth several times between the two blending tanks. They are then pneumatically conveyed to a bulk storage bin such as the one behind the blending tanks.

A view of the operating platform is shown in Fig. 6.11. On the far right is the remote control box for the injection pump. From his station the operator can read the wellhead and pump pressures from the gages on the instrument panel immediately in front of him. He can also observe the slurry in the surge tank through the mirror just above the instrument panel. On the left of the instrument panel are the controls for the waste pumps. At the far left of the picture is the station of an operator who regulates the rate of dry solids feed to the mixer hopper. He observes the level of dry solids in the hopper through the window in the cell wall and a corresponding window in the hopper and regulates a butterfly valve to keep the level constant.

A view of the wellhead of the injection well with the piping arranged for injection is shown in Fig. 6.12. The bottom fitting is the head of the $9\frac{5}{8}$-in. surface casing. The next fitting above is the tubing head, which provides connections to the $5\frac{1}{2}$-in. casing. The flanged valve on the left connects to a pressure gage, and the flanged valve on the right connects to the valve rack and to

Fig. 6.5. Cell Enclosing Wellhead.

either the injection pump or the waste pit. Above the tubing head is the adapter flange, which supports the tubing string. Above the adapter flange is the master valve, and above the master valve is the plug container, which holds a wiper plug for wiping surplus cement from the inside of the tubing string at the end of a run. The connection on the plug container leads to the valve rack and the injection pump. All piping shown is rated at 10,000 psi.

Figure 6.13 shows the principal features of the hydraulic fracturing plant in their relative locations. The emergency waste trench is a safety measure against the unlikely possibility that, late in the course of a waste injection, the wellhead ruptures, allowing the injected grout to flow back up the well with no way of stopping the flow. Should such an event occur, the grout would flow from the wellhead cell through an 18-in. line to the 100,000-gal waste trench, where it would set and would not be a serious hazard. The blending tanks (just north of the bulk storage bins) are 800-ft^3 pressure tanks that are used prior to an injection to blend the dry solids mix.

Each injection consists of two phases — the preliminary preparations (which require about a week to complete) and the injection itself (which requires from 4 to 12 hr). The preliminary prepa-

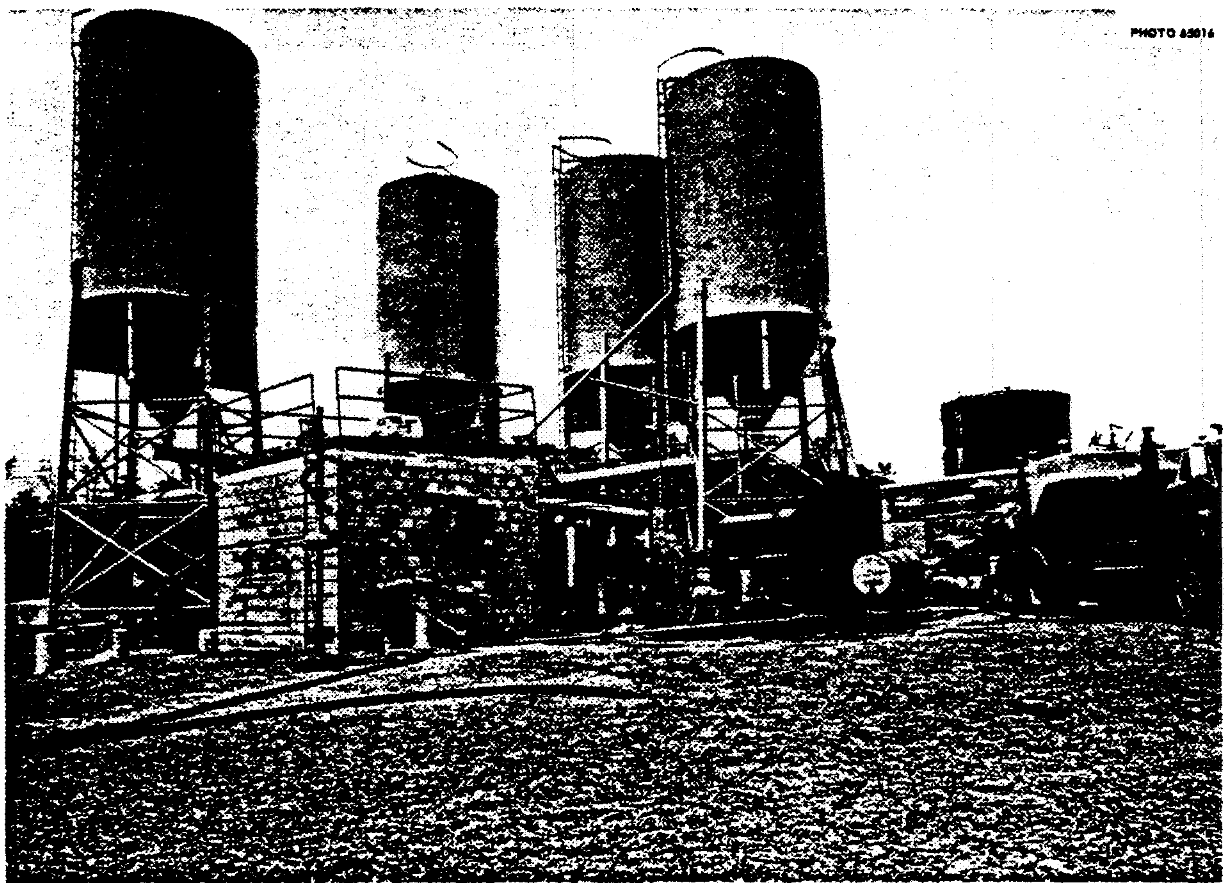

Fig. 6.6. View of the Hydraulic Fracturing Plant Showing Four Bulk Storage Bins, Wellhead Cell (Left Foreground), Main Injection Pump, and Standby Pump Unit.

rations include the transfer of waste solution to the site, the blending of the dry solids mix, and the slotting of the injection well.

The waste solution is pumped to the site through the existing waste transfer system and stored in the three underground waste storage tanks. The tanks are agitated and sampled. The sample is mixed with a cement mix of the same composition that is intended for use in the injection and the setting time determined so that adjustments in the mix can be made if necessary.

The dry solids mix is usually blended a week before the injection. A typical mix consists of cement, two types of clay, and a small amount of retarder. Bulk cement is brought to the site in pneumatic transporter trucks; the other constituents of the solids mix are procured in bags. A batch of cement is charged to a blending tank, and the other components are added in proportion. The mix is then blown back and forth between the two blending tanks until mixing is complete. The mixed dry solids are then blown to a bulk storage bin, and another batch is mixed. This operation is continued until all the dry solids required for the injection have been blended and stored.

A day or two before an injection, the well casing is slotted at the depth of the proposed injection by a technique known to the service companies as "hydrajet" or "sandril." In this tech-

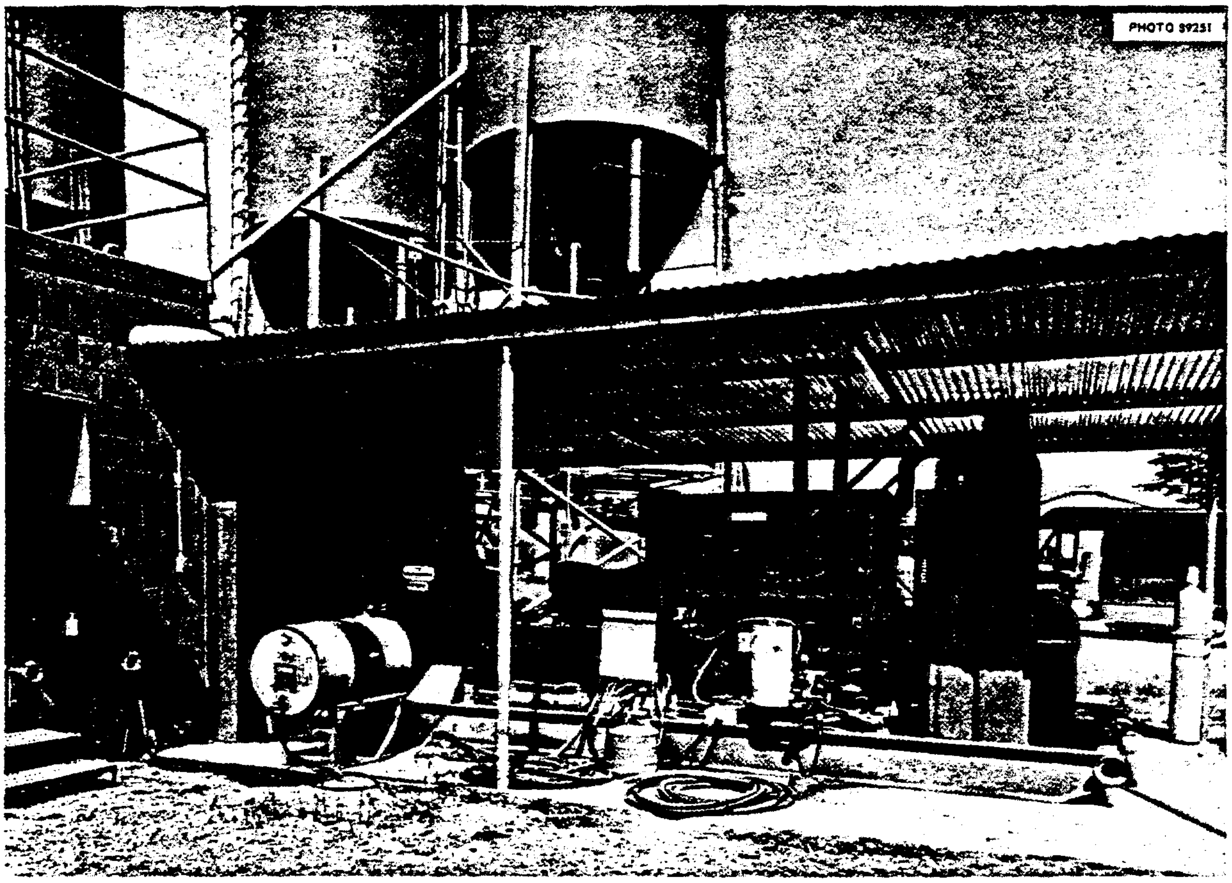

Fig. 6.7. High-Pressure Injection Pump, Diesel Engine, and Gear Drive.

nique a slurry of sand and water is pumped down a string of tubing hanging in the injection well and out a jet at the bottom of the tubing string to impinge on the casing at that point. The erosive action of the sand cuts the casing and the surrounding shale formation to a sufficient depth to make subsequent initiation of the desired fracture relatively easy. The spent slurry is brought to the surface through the annulus between the tubing and the casing, the degraded sand is allowed to settle in a waste pit, and the water is recirculated, so that the volume of contaminated water produced by the slotting operation can be kept to a minimum. The tubing string is slowly rotated by a hydraulic power swivel, so that a complete cut of the casing is made. This phase of the operation requires about 30 min. At this time the jet at the bottom of the tubing string is dislodged and brought to the surface by pumping water down the annulus between the tubing and the casing. The sand remaining in the well is backwashed out. Several tubing sections are then removed to raise the bottom of the tubing string about 20 ft above the slot in the casing. This is done so that the tubing will not be cemented to the bottom of the well by the plug of cement used to seal each injection. Water is then pumped into the injection well, and the pressure is allowed to increase until the formation fractures. The initiation of the fracture is indicated by a sudden and significant

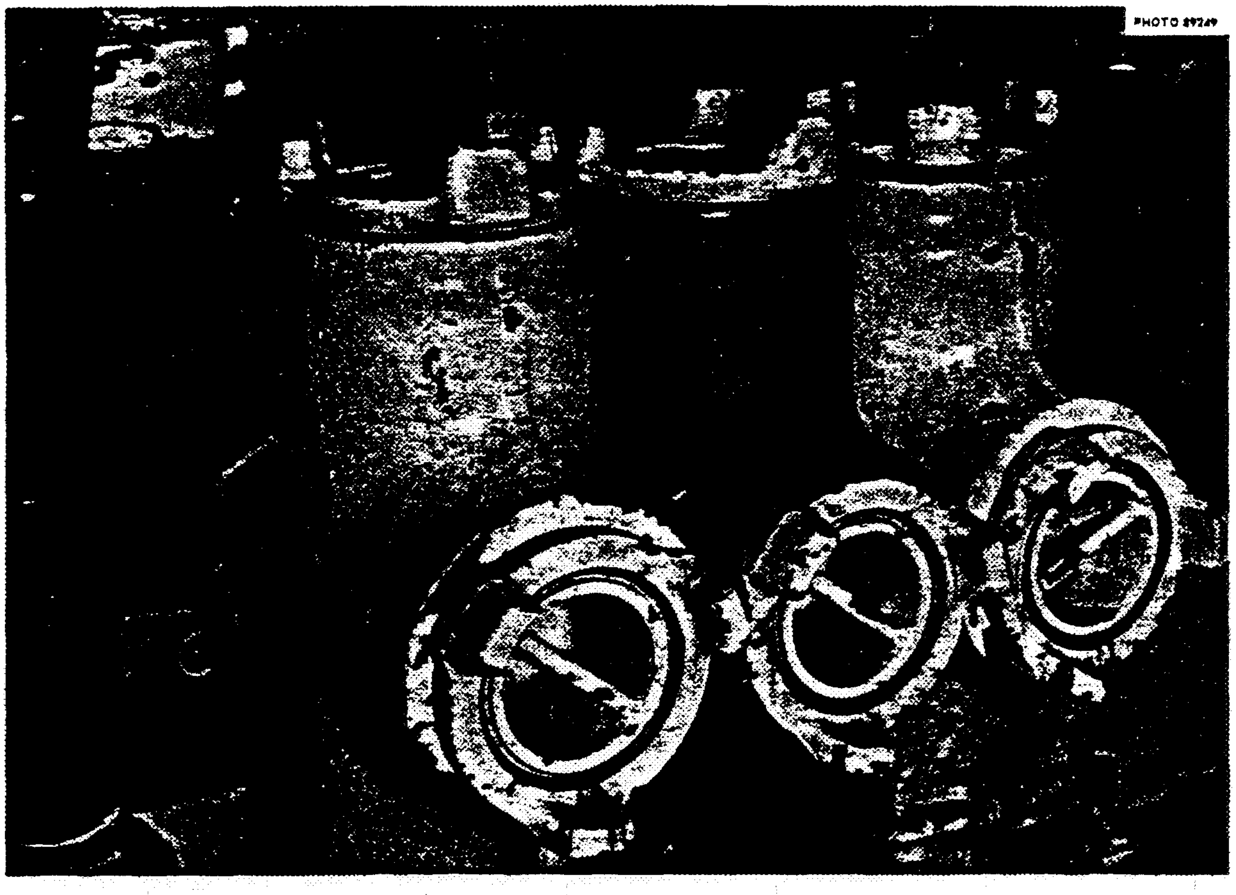

Fig. 6.8. High-Pressure Injection Pump Cylinders and Valve Containers.

drop in the injection pressure. In the experimental injections at the hydraulic fracturing site, this drop has occurred at injection pressures as low as 1800 psi and as high as 5000 psi. In all cases, however, the pressure has been well above the overburden pressure of the formation when the fracture occurred. This fact is of significance because of the current theory that fracturing pressures higher than the overburden pressure indicate that horizontal fractures are being formed; fracturing pressures lower than the overburden pressure indicate that vertical fractures are being formed.[2]

The final preliminary preparation is to check the packing of the injection pumps and to replace it if necessary. The new packing is run in by pumping water through the system for about $\frac{1}{2}$ hr. This completes the preparations for the injection.

At the start of a waste injection, all access hatches to the cells are closed, and the off-gas blower is turned on. This blower draws air from the mixer hopper, the surge tank, and the three cells and discharges it through a set of filters and up a short stack. Waste solution is then

[2]M. K. Hubbert and W. G. Willis, "Mechanics of Hydraulic Fracturing," *Petrol. Trans. AIME* 210, 153 (1957).

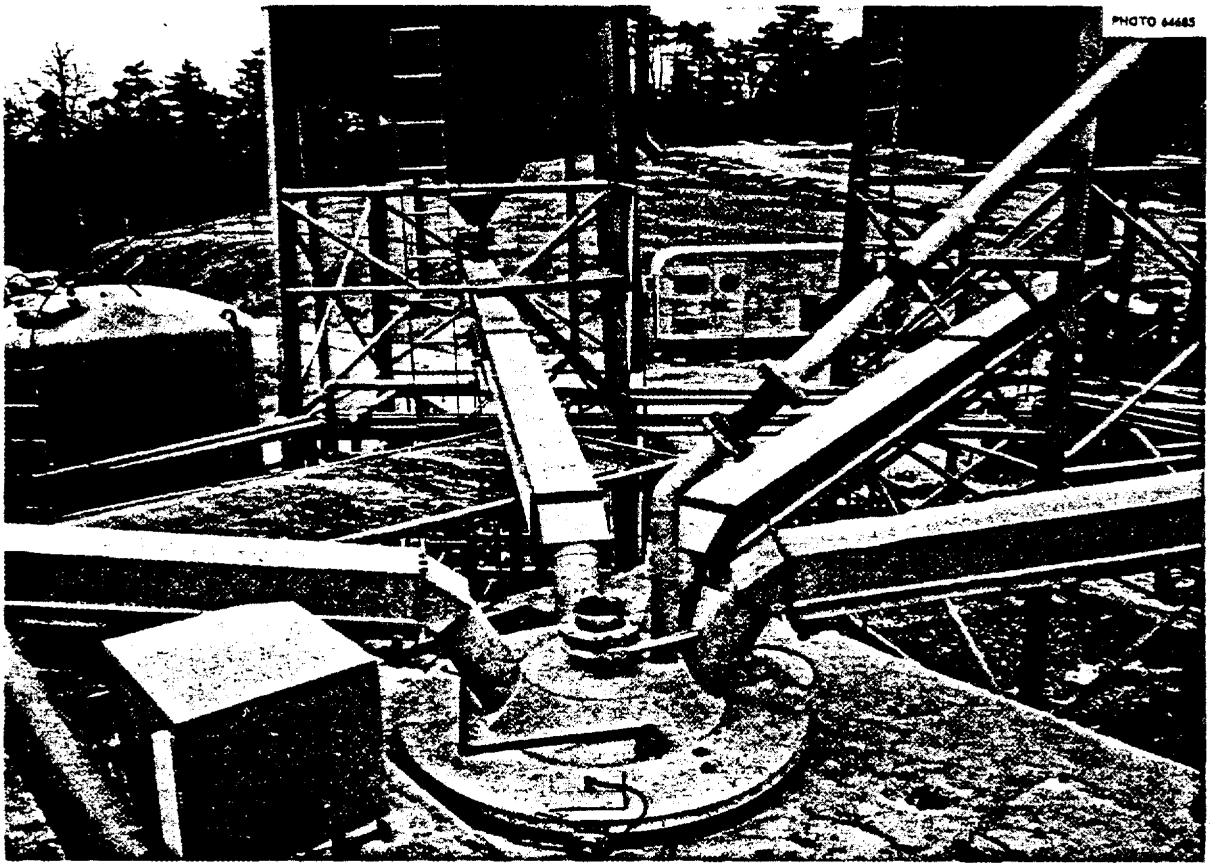

Fig. 6.9. Pneumatic Conveyors for Transferring Preblended Solids from Bulk Storage Bins to the Mixer Hopper.

pumped to the mixer and mixed with dry solids from the bulk storage bins. The resulting slurry is pumped down the tubing hung in the injection well and out into the fracture. Injection of waste continues in this fashion until the end of the run. At the end of the run a cement-water grout is pumped down the well and out into the formation to isolate the radioactive grout from the injection well. This "plug" is followed by a rubber wiper plug to wipe grout from the wall of the tubing string and by enough water to force the final grout level down to a few feet above the slot in the casing. The well is then valved shut until the plug sets.

CONTROL OF MIX PROPORTIONING

Very early in the mix development program the feeling that the properties of a grout would be greatly affected by the proportion of solids to liquid used in the blending of the grout was confirmed.[3] It was found that variations of $\frac{1}{2}$ lb of solids per gallon of waste could make the differ-

[3] "Radioactive Waste Disposal," *Health Phys. Div. Ann. Progr. Rept. July 31, 1962*, ORNL-3347.

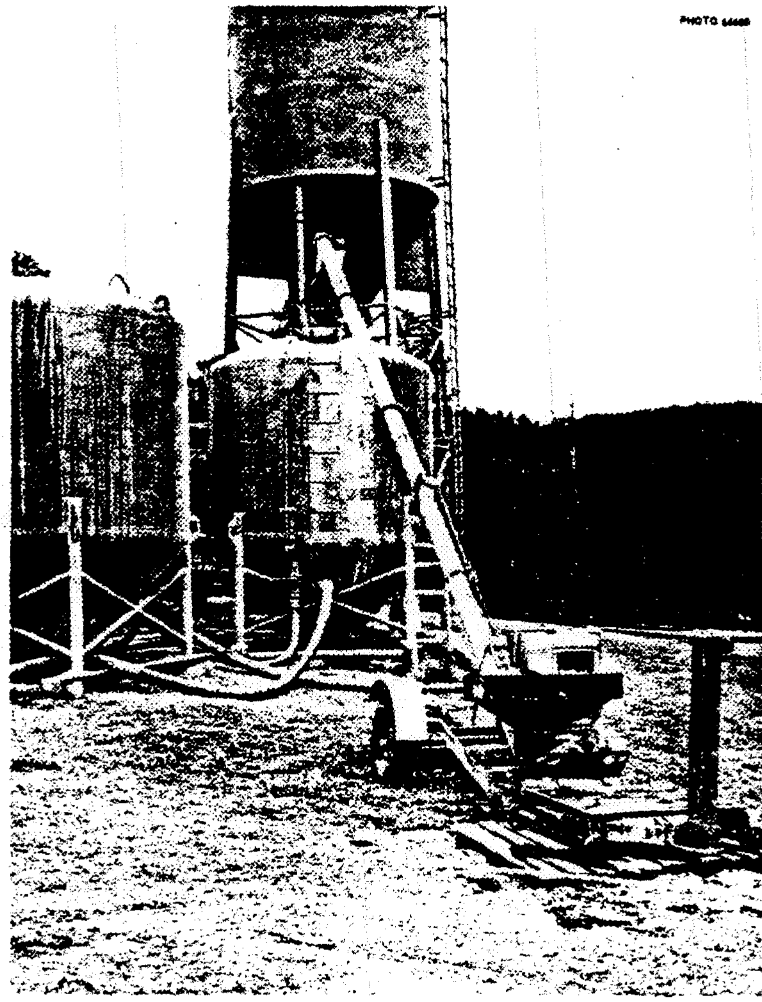

Fig. 6.10. Equipment for Proportioning and Blending Dry Solids.

ence between a good grout and a grout that was too thick to pump smoothly or a grout that was so thin that phase separation would occur when the grout set. This being the case, a fairly precise control of the proportioning of solids to liquid was necessary throughout an injection.

The method of control that was adopted is a modification of that in use by the oil-well service companies. This method is illustrated in Fig. 6.14, which shows the operations that are performed in the mixer cell. Waste solution is pumped from the waste storage tanks through the jet mixer under a pressure of 100 psi. The stream of waste solution passing through the jet mixer pulls the cement into the mixer bowl from the hopper above; the two streams are thoroughly mixed in the outlet pipe and are discharged into the surge tank. A small hydraulic pump mounted in the surge tank continuously pumps grout from the surge tank through a Densometer and back to the surge tank. The Densometer is a Halliburton device that continuously measures the density of the fluid circulating through it. This measured grout density is assumed to be proportional to the amount of

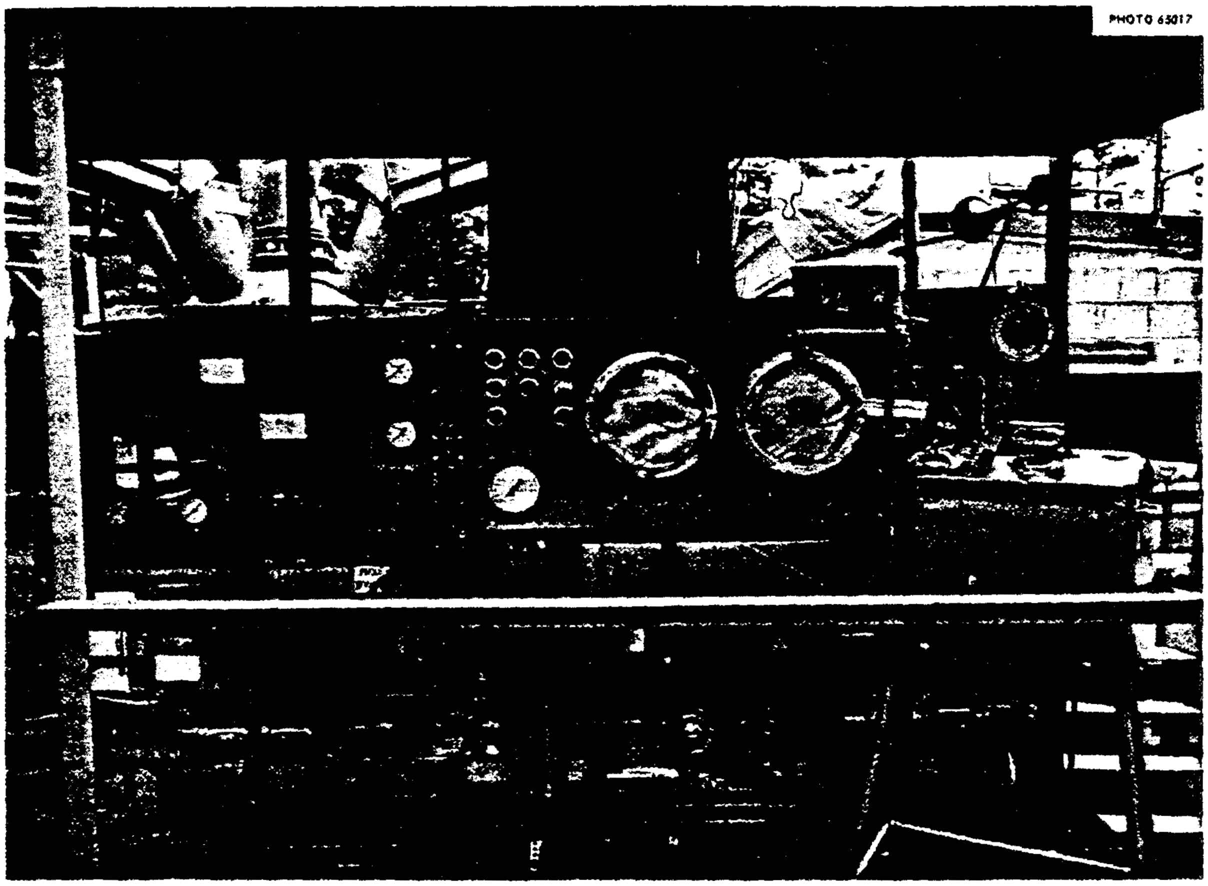

Fig. 6.11. Operating Panel Outside the Mixer Cell.

solids in the grout (this assumption has been verified experimentally) and, throughout the injection, is kept as close as possible to the value that corresponds to the desired mix ratio. This is done by regulating a bypass stream around the jet mixer to either increase or decrease the dilution of the mixed grout. The rate of addition of solids to the jet mixer is kept constant by maintaining a constant level in the mixer hopper. This is done by manual operation of a butterfly valve according to visual observation of the dry solids level in the mixer hopper.

The basic assumption involved in this method of control is that the grout density is proportional to the amount of solids in the grout. This assumption is correct enough; there is a proportionality. Unfortunately, however, the grout density is also dependent on the density of the solution used and the amount of air entrapped with the grout. Also, and more critically, a 10% change in the proportion of the solids in the grout is reflected as a 2% change in grout density. That is, the process must be controlled with a relatively insensitive indicator.

Air entrapment in the grout is greatly reduced by the addition of a defoaming agent to the waste solution (see Chap. 5). When this defoaming agent is used, most of the air in the grout escapes

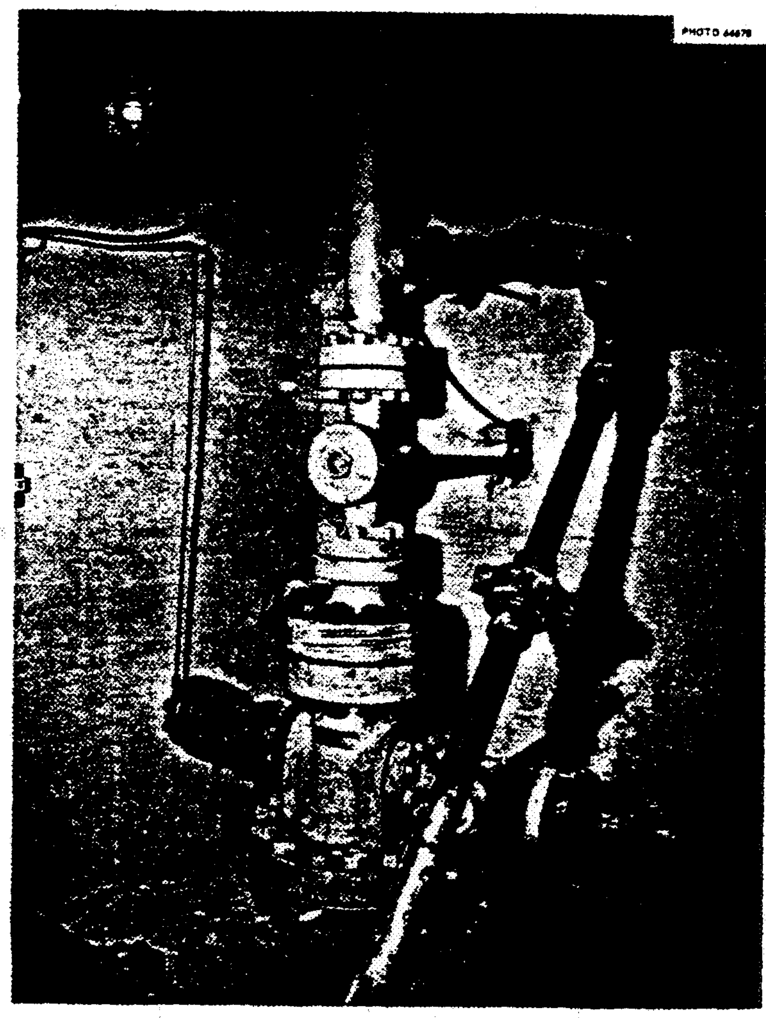

Fig. 6.12. Wellhead of the Injection Well.

while the grout is in the surge tank. A small amount of air remains with the grout, but this volume is constant enough to be corrected for by an adjustment to the proportionality curve.

The problem resulting from the dependence of the grout density on the waste solution density has not been satisfactorily solved. In the injections made to date, this dependence has been corrected for by a careful measurement of the waste solution density prior to the injection, the determination by a series of laboratory tests of the variation of the grout density with the mix ratio for this particular waste solution, and the use of this information to select the grout density to be maintained during the injection. As long as the solution density does not change during an injection, this procedure is adequate – barely.

Figure 6.15 shows proportionality curves that were obtained for two different waste solutions – water and a concentrated waste. The inherent difficulty of the control problem can be seen by an examination of this curve. If the dilute waste solution is to be injected at a mix ratio of 8 lb of

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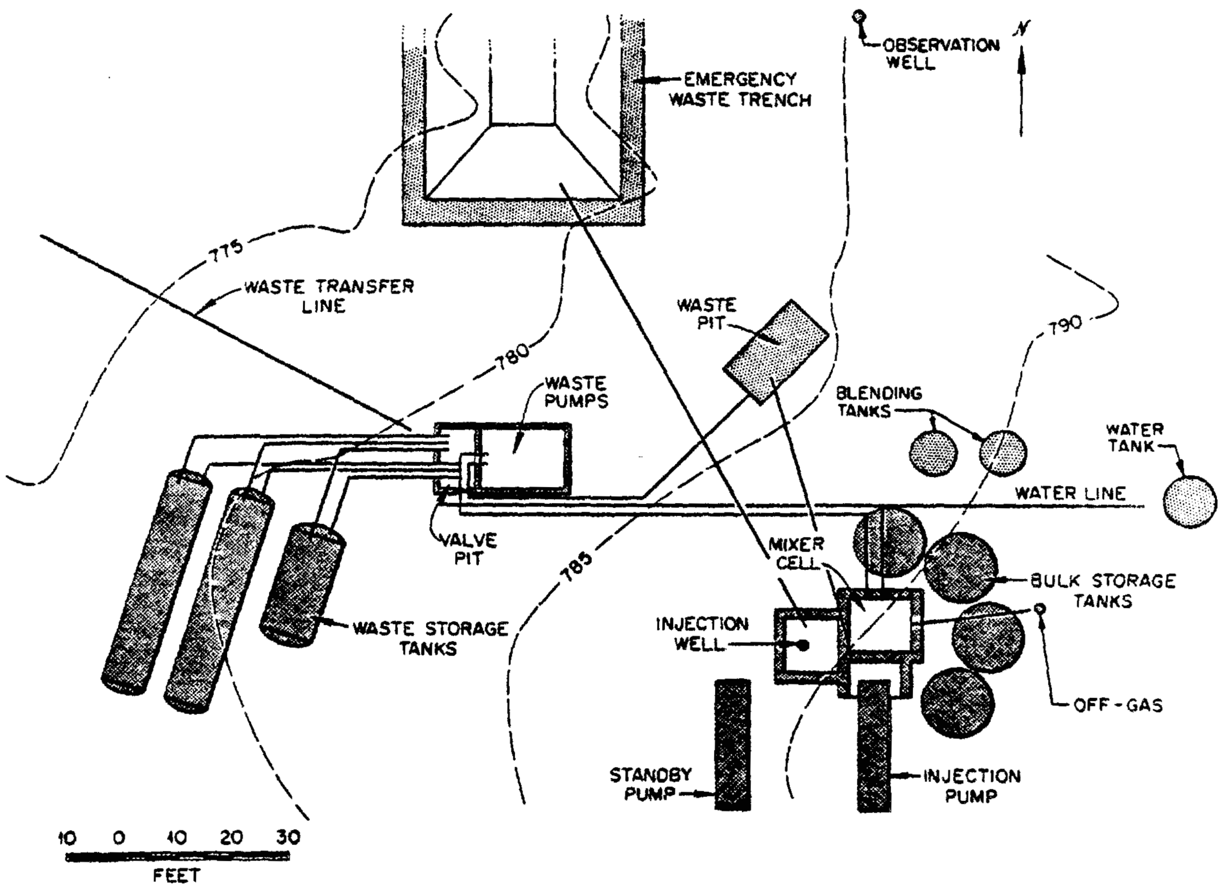

Fig. 6.13. Layout of the Hydraulic Fracturing Plant.

dry solids per gallon of waste, the desired grout density is 12.65 lb/gal (assuming that the curve is entirely accurate). Operating experience has shown that control of the grout density to within ±0.2 lb/gal is extremely good; this is equivalent to a mix ratio of between 7.5 and 8.6 lb of dry solids per gallon of waste. This is the best that can be hoped for; a variation in solution density, a change in the amount of entrapped air, inaccuracies in the determination of the curve, less than perfect control – all these will tend to increase the error.

Despite all these drawbacks, this method of mix control was used for the first series of experimental injections. Development of an alternate method of control would have required considerable time, and it was thought more important to proceed with the first injections as rapidly as possible.

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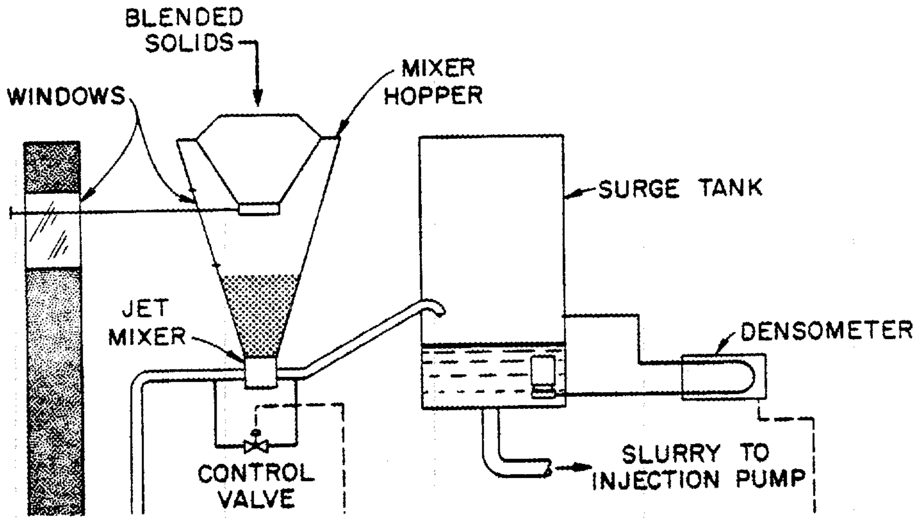

Fig. 6.14. Equipment for Proportioning and Mixing Preblended Dry Solids and Liquid Waste.

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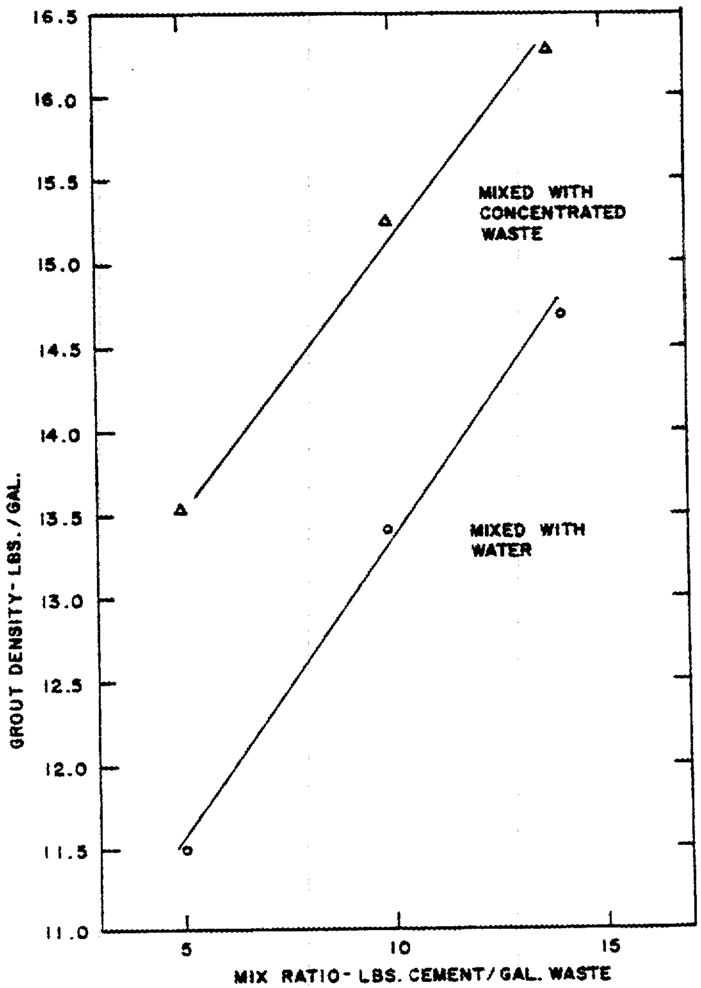

Fig. 6.15. Correlation of Mix Ratio and Grout Density.

7. Experimental Injections, 1 Through 5

The first series of five experimental injections were made to check on the performance of the surface plant and to determine the underground behavior of the slurries of different compositions. It was anticipated that as the experimental injections were made, plant performance would be evaluated and changes incorporated wherever necessary. Following these injections, coring operations were planned to provide information on the dispersion of the grout underground as well as on the properties of the grouts.

Prior to startup of this series of field tests, the objectives of the first five injections were defined. These objectives are described here to provide a better understanding of the injections individually described later.

The first injection was made to check the operation of the surface plant and to evaluate a nonsetting mix. The nonsetting mix was prepared with 10X waste and attapulgite, and its consistency was similar to the setting mixes used later.

The objectives of the second injection were to evaluate a mix with low cement content and to determine whether the grout sheet could be detected at the cased observation well. Short-life ^{198}Au was used as a tracer, its 2.70-day half-life allowing detection at the observation well without presenting a serious hazard if leaks or contamination problems developed in the surface plant. Since coring was not planned until after completion of the first five injections, no radiation hazard was anticipated even if the low-cement grout failed to set.

The third injection was made to demonstrate that concentrated radioactive waste solutions similar to those anticipated from the ORNL waste evaporator (10X) could be fixed permanently underground. The mix for this injection was designed to set into a strong, dense grout which would withstand core drilling operations and thus be recovered.

The objective of the fourth injection was to evaluate a mix designed for dilute waste solutions (1X) with grout strength of intermediate value. In both injections 3 and 4, the source of radioactivity was actual ORNL waste containing ^{137}Cs primarily.

The fifth and last in this series of injections was made to test the surface plant during an extended (11-hr) disposal operation and to determine the underground behavior of a large ($>$100,000-gal) injection. Earlier injections were limited to volumes of approximately 35,000 gal, which required only 3 hr of pumping. The mix for this injection included illite, sometimes referred to by its commercial name of Grundite, cement, attapulgite, and DGL. The last three materials were also used in injections 2, 3, and 4.

Following the fifth injection, core drilling was carried out to determine the dispersion patterns of the grout and to recover cores for evaluating the mixes used in the injections.

WASTE COMPOSITION, MIX FORMULATION, AND SLURRY PROPERTIES

Waste Compositions

Waste solutions used in the first series of five experimental injections differed considerably in chemical composition and radionuclide concentration. The gross chemical composition and radionuclide content of the five waste solutions are summarized in Table 7.1. Only synthetic waste solutions were used in injections 1 and 2; 30 curies of ^{198}Au was added as a tracer in the second injection. In injection 1, Pontacyl Brilliant Pink dye was added to the injection solution, and Rhodamine B dye was used in injection 2 to serve as distinctive markers of these grout sheets on recovery of cores during subsequent test drilling.

The chemical composition of the waste solution for injection 3 was slightly different from that for injections 1 and 2 because 7500 gal of actual ORNL waste was mixed with 15,800 gal of 12X synthetic waste and 13,000 gal of 10X synthetic waste. The ORNL waste was lower in chemical content than the anticipated 1X waste. In the fourth injection, the actual ORNL waste was even lower in concentration than the values shown in Table 7.1 because about

Table 7.1. Chemical and Radionuclide Composition of Waste Solutions Used in Injections 1 Through 5

	Injections 1 and 2	Injection 3	Injection 4	Injection 5[a] "A"	Injection 5[a] "B"	Injection 5[a] "C"
Chemical Composition (*M*)						
Sodium hydroxide	2.0	1.9	0.13	0.04	0.12	0.04
Sodium nitrate	2.9	2.7	0.21	0.06	0.30	0.07
Ammonium sulfate	0.20	0.19	0.01	0.005	0.01	0.01
Aluminum sulfate	0.20	0.19	0.02	0.003	0.02	0.005
Sodium carbonate	0.20	0.19	0.02	0.02	0.06	0.02
Radionuclide Content (curies)						
^{198}Au	30[b]					
^{90}Sr		4.9	0.9	380	210	18
^{137}Cs		74	50	125	15	3
^{106}Ru		0.4	1.2	30	3	2
^{60}Co		0.1	0.1	1	2	1
^{144}Ce				285	3550	264

[a]In injection 5 the waste storage tanks were originally filled (40,000 gal) with ORNL waste spiked with ^{144}Ce and later refilled with synthetic waste after the original waste was disposed of. "A" refers to the original ORNL waste, "B" to the first synthetic waste refill, and "C" to the second synthetic waste refill. Activities in "B" and "C" were present in the tanks originally and had settled to the bottom; when the tanks were refilled, the agitation resuspended the solids and thus caused "B" and "C" synthetic wastes to be radioactive.

[b]30 curies of ^{198}Au was used only in injection 2.

2000 gal of waste from injection 3 was left in the tank. The total radionuclide concentration in injection 4 was lower than that in injection 3 even though no synthetic waste solution was used. This was not totally unexpected since actual ORNL waste changes from time to time, depending on Laboratory operations.

The operating tank capacity at the shale fracturing plant was only 40,000 gal. Therefore, to provide the volume required for injection 5, the emergency waste trench was used to store the additional volume of synthetic 1X waste needed to make up the entire batch. The difference in chemical composition between "B" and "C" (Table 7.1) was judged to be due to incomplete mixing of the waste in the trench. In addition to actual ORNL waste, approximately 4000 curies of ^{144}Ce was added to enable identification of the grout when cored. The high concentration of ^{144}Ce in "B" was not expected; earlier sampling of the tanks had shown very little ^{144}Ce. Since the ^{144}Ce had been added to the waste at the ORNL tank farm, it was first believed that this radionuclide had hydrolyzed, settled, and remained in the tank at the tank farm. Its appearance in "B" can only be explained by its transfer to the tanks at the shale fracturing plant followed by rapid settling. When synthetic waste was then pumped into the tanks after the original ORNL waste had been disposed of, the settled solids must have been resuspended.

Mix for Injection 1

This mix was developed for the prime purpose of pressure testing the assembled field equipment with a slurry of relatively high viscosity. The long-term behavior of the slurry is not known; if slow chemical interactions of the components produce an immobile solid, this type of cheap slurry may be of value for later applications. The slurry had the following composition and properties:

Composition	0.67 lb Attapulgus 150 per gallon of waste
Viscosity	9 poises
Water separation	Approximately 0.4%
Fluid loss	
100-psi test	104 cc/30 min
1000-psi test	166 cc/30 min
Pumping time	Indefinite
Material cost	1.1 ¢/gal

This slurry had approximately the same viscosity as the cement slurries used in subsequent injections.

Mix for Injection 2

This mix was developed as a low-cost setting mix that could be used with concentrated waste solutions. A cement concentration higher than necessary was used to increase the chance of recovering an intact core on subsequent drilling. This slurry had the following composition and properties:

Composition	10X concentrated synthetic waste with 250 ppm TBP 5 lb portland cement (type II) per gallon of waste 0.5 lb Attapulgus 150 per gallon of waste 0.015 lb DGL per gallon of waste
Density	13.5 lb/gal
Volume	1.21 gal per gallon of waste
Viscosity	3 poises
Water separation	0.1% prior to setting; 0.0% after setting
Fluid loss	
100-psi test	158 cc/30 min
1000-psi test	302 cc/30 min
Pumping time	11.3 hr at 89°F
Compressive strength	235 psi after 28 days and 65°F curing
Material cost	7.0 ¢/gal

The use of type II cement was considered desirable after tests with grouts made from type I cement revealed that deterioration set in after 28 days of setting. Type II cement is resistant to deterioration by the action of sulfates, which are present in ORNL's waste solutions. Sulfate action was also suspected as the cause of the reduction of compressive strength with time, which occurs with type I cement.

Mix for Injection 3

This mix was developed to provide a slurry for simulated 10X waste which, on setting, would have a high compressive strength. This slurry had the following composition and properties:

Composition	9.4X concentrated synthetic waste with 400 ppm TBP; 20% of total volume was ORNL waste 14 lb type II cement per gallon of waste 0.28 lb Attapulgus 150 per gallon of waste 0.021 lb DGL per gallon of waste
Density	15.8 lb/gal
Volume	1.5 gal per gallon of waste
Viscosity	10 poises
Water separation	0 before and after setting
Fluid loss[a]	
1000-psi test	122 cc/30 min
100-psi test	30 cc/30 min
Pumping time	9 hr 45 min
Compressive strength	2700 psi after 28 days at 65°F
Materials cost	~15.5 ¢/gal

[a]Tests performed on slurry containing 0.028 lb DGL.

A sample of this slurry obtained from the fracturing plant during the injection indicated a pumping time of 6 hr and 15 min. The lower pumping time may have been due to an uneven distribution of retarder in the cement.

Mix for Injection 4

In injection 4, the waste solution used was essentially ORNL 1X intermediate-level waste. The reduced concentration of dissolved salts in this waste required a different mix formulation. In addition, a 1000-psi compressive strength was desired. This slurry had the following composition and properties:

Composition	ORNL ILW with 400 ppm TBP 10 lb type II cement per gallon of waste 0.46 lb Attapulgus 150 per gallon of waste 0.01 lb DGL per gallon of waste
Density	13.5 lb/gal
Volume	1.40 gal per gallon of waste
Viscosity	8 poises
Water separation	0 cc before and after setting
Fluid loss	278 cc/30 min using 100-psi test
Pumping time	6 hr 40 min at 89°F
Compressive strength	770 psi after 8 days at 80°F
Materials cost	11.3 ¢ per gallon of waste

A test of this mix with a waste sample taken from the storage tanks at the plant site indicated a pumping time of 9 hr 50 min. The longer pumping time in this case was attributed to a lower caustic content in the actual waste than in the synthetic waste.

Mix for Injection 5

Since this injection was planned to test the performance of the plant over an extended period of continuous pumping, the mix was designed to be pumpable for over 18 hr. In addition to the three basic ingredients (cement, Attapulgus 150, and DGL), illite was added to improve cesium retention in the grout. Tests had shown that ^{137}Cs, the major source of activity in ORNL waste, leached from grouts prepared with only the three basic ingredients. This slurry had the following composition and properties:

Composition	35% ORNL ILW and 65% 1X synthetic waste with 400 ppm TBP 6.5 lb type II cement per gallon of waste 0.65 lb Attapulgus 150 per gallon of waste 0.45 lb Grundite per gallon of waste 0.02 lb DGL per gallon of waste
Density	12.4 lb/gal
Volume	1.33 gal per gallon of waste

Viscosity	5 poises
Water separation	0 before and after setting
Fluid loss	230 cc/30 min using 100-psi test
Pumping time at 89°F	19 hr 30 min
Compressive strength	370 psi after 7 days at 80°F
Materials cost	9.1 ¢ per gallon of waste

Figure 7.1 is a plot of the waste and slurry densities of mixes used in injections 2 through 5. Note that injections 2 and 3 were made with 10X waste and injections 4 and 5 with 1X waste. The information shown in this figure is necessary for solid/liquid proportioning control. Since the Densometer control system operates on the basis of the weight of the slurry, the operator needs to know the density of the waste and of the slurry for each injection. Ideally, the difference in density between the waste and the slurry should be large; with small differences, the errors in Densometer control will result in large errors in proportioning. Later injections used a mass flowmeter to complement the Densometer for proportioning; this was necessitated by the desire for economical low-solids blends which involve relatively small differences in densities. This mass flowmeter is described in Chap. 8.

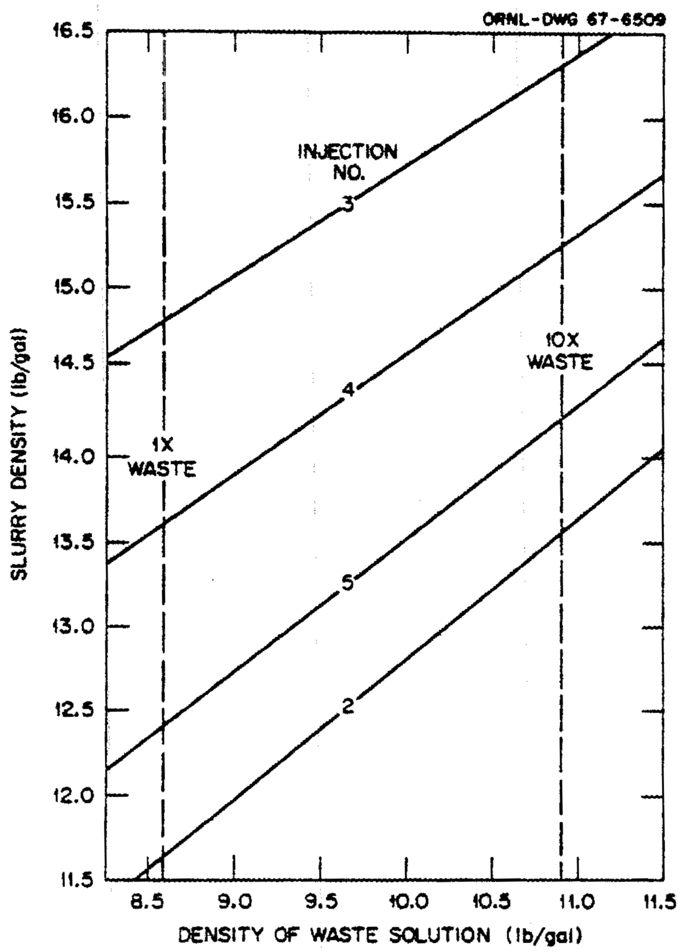

Fig. 7.1. Slurry Densities of Mixes Used in Injections 2 to 5.

INJECTION 1

Preliminary Preparations

No solids mixing was required for this run, since attapulgite drilling clay was the only solid to be added. The charge of 23,400 lb of Attapulgus 150 was put into one of the bulk storage bins prior to the injection. The synthetic waste solution in the storage tanks (40,500 gal) was evenly distributed among the three tanks by pumping from one tank into another. A dye (Pontacyl Brilliant Pink) was added to the waste in each tank.

The well was slotted at a depth of 945 ft on February 11, 1964, by circulating a slurry of sand and water through the jet tool for approximately 40 min at an average pressure of about 5200 psi. The tool had two jets, each $3/16$ in. in diameter. The sand consumption was 37 sacks of 10–30 round sand.

After slotting was judged to be complete, the jet tool was pumped to the surface and held in the jet catcher. The well was backwashed to clear the sand from the well. The swivel and slick joint (equipment necessary for slotting) were removed from the wellhead assembly, several joints of tubing were removed to bring the bottom of the tubing string approximately 20 ft above the level of the slot, and the master valve and plug container were installed on the wellhead.

Pressure was applied to the well and increased until the formation fractured at 2150 psi. Flow was then increased to extend the fracture; a total of 3000 gal of water was pumped into the fracture at this time.

Injection

The injection was started at 3:30 PM, February 13, 1964. Almost immediately after the start of the injection, a temporary patch on an unused air slide broke loose and discharged attapulgite on the roof of the mixer cell. The injection was halted while the patch was repaired and was then resumed. About 20 min after the injection was resumed, the waste pump stopped. The other waste pump was started but stopped almost at once. Both pumps were then started together and ran well during the rest of the injection. With the exception of the two incidents mentioned above, the injection was uneventful. The injection was terminated at 6:00 PM, when the supply of attapulgite was exhausted.

Plots of the injection pressure and the volume injected are shown in Figs. 7.2 and 7.3. A total of 37,300 gal of waste was mixed with 23,400 lb of attapulgite and injected at an average rate of 250 gpm. The average mix proportion of 0.63 lb of clay per gallon of waste was acceptably close to the desired proportion of 0.67 lb/gal.

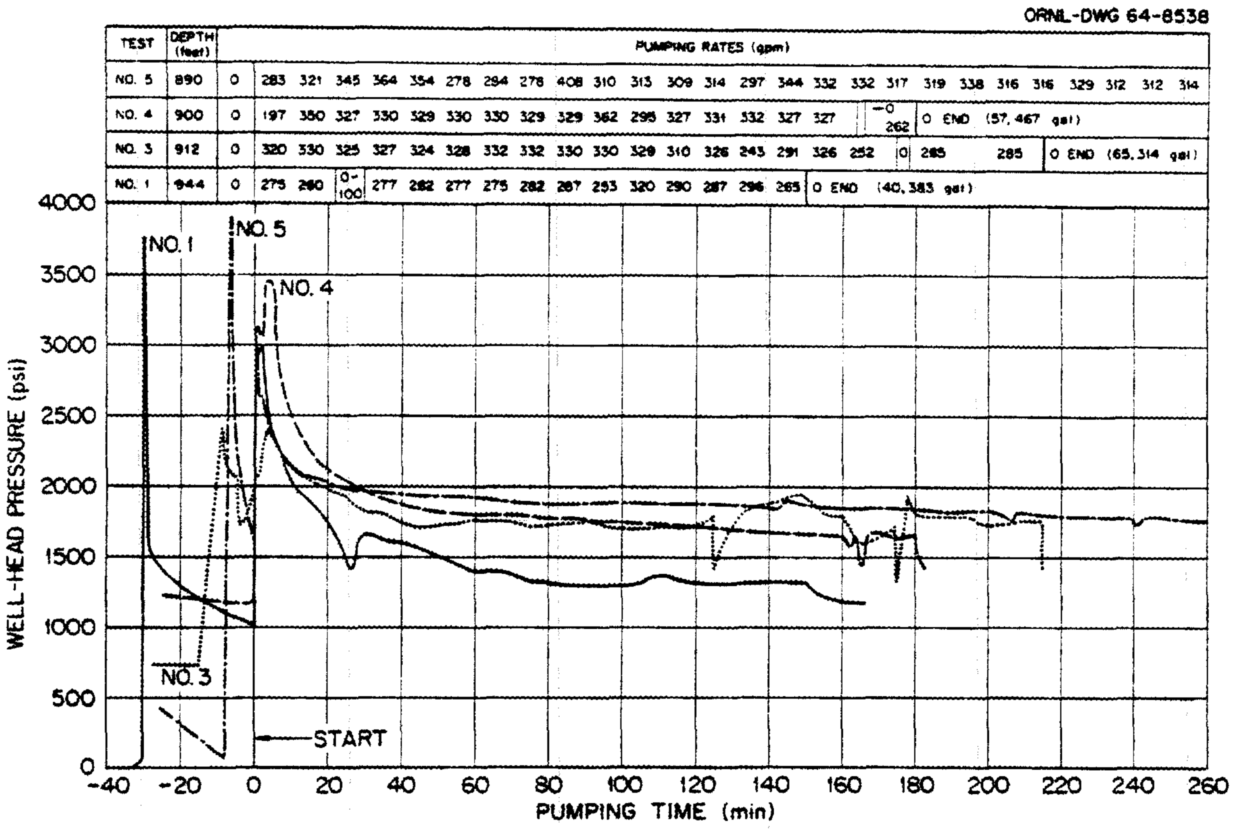

Fig. 7.2. Pumping Pressures for Injections 1, 3, 4, and 5. Measured on stagnant annulus of injection well.

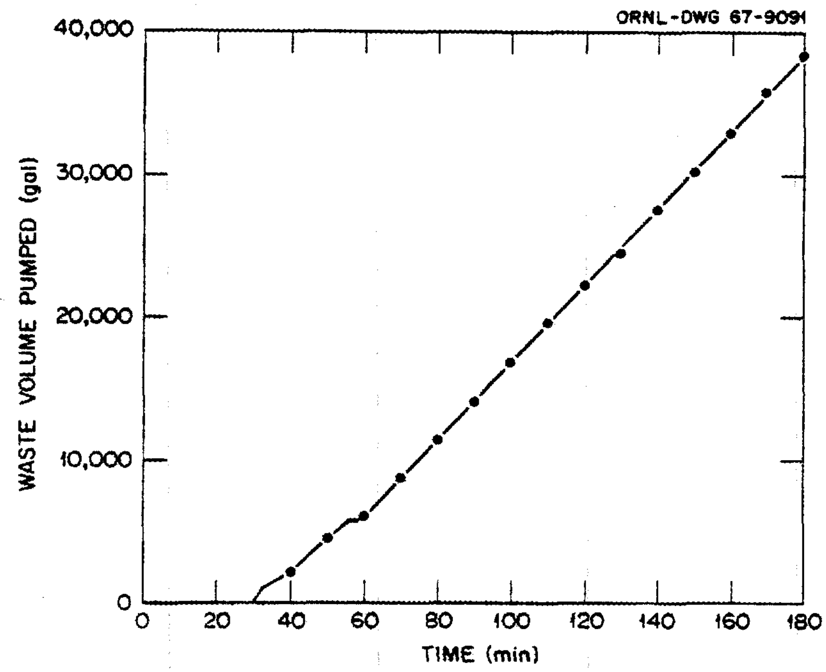

Fig. 7.3. Cumulative Volume Pumped, Injection 1.

INJECTION 2

Preliminary Preparations

Four P-tankloads of solids were mixed. Each load consisted of 48,000 lb of cement from a bulk truck, 48 sacks of attapulgite, and 216 lb of retarder (DGL). A mixture of 100 sacks of cement and 10 sacks of attapulgite was blended and stored separately.

The waste storage tanks were refilled with synthetic 10X waste solution. A dye (Rhodamine B) and approximately 10 curies of ^{198}Au were added to the waste in each tank. The solution in each tank was mixed by air sparging.

The well was slotted at a depth of 924 ft on February 19, 1964, by circulating a slurry of sand and water through the jet tool for approximately 1 hr at an average pressure of 3800 psi. A new jet tool was used for this job; the tool had four jets $^3/_{16}$ in. in diameter instead of the two jets of the tool used previously. A total of 37 sacks of 10–30 round sand was used.

During the slotting operation the waste pumps would not deliver the necessary fluid volume and pressure. Since the sand could not be kept in suspension at the reduced output of the waste pumps, there was some danger of "sanding out" the well (plugging the bottom of the well with compacted sand). It was accordingly necessary to use the standby pumps to pump water from the water storage tank to the slurry tub, to obtain the necessary flow of water. The waste pumps were retested after the slotting had been completed and were found to be functioning normally.

Pressure was applied to the well and increased until the formation fractured at 3800 psi. Flow was then increased to extend the fracture; a total of about 2400 gal of water was pumped into the fracture at this time.

Injection

The injection was started the afternoon of February 20, 1964. It quickly became apparent that the waste pumps were not delivering the necessary volume of waste solution, and it was not possible to mix the solids being fed to the mixer with sufficient waste to obtain the desired slurry density. The pumps were flushed with water in an attempt to clear them, but this failed to improve their performance. After 45 min of unsatisfactory operation, the injection was terminated by overflushing the slot in the casing with 500 gal of water. Approximately 1000 gal of waste solution, 3600 gal of water, and 32,600 lb of solids mix were consumed.

A check of the waste pumps revealed that the intake lines of these pumps were plugged, most likely at their common strainer. The strainer was removed and found to be plugged by an accumulation of small particles. It was replaced by one with a much coarser screen.

The injection was restarted at 10:25 AM, February 21, 1964. All major components operated satisfactorily, and the injection continued until the supply of solids was exhausted at 12:23 PM. Approximately 27,300 gal of waste was pumped at an average rate of 227 gpm. The average cement content of the slurry was 5.87 lb/gal.

A plot of the volume of waste pumped as indicated from the level readings of the waste tanks is shown in Fig. 7.4. Figure 7.5 is a plot of the injection pressures.

Readings of the intensity of the direct radiation were taken during the run at several points. Airborne contamination in the air withdrawn from the hopper and slurry tub was also measured, and no activity was found. In the valve pit and immediately adjacent to the waste pumps the

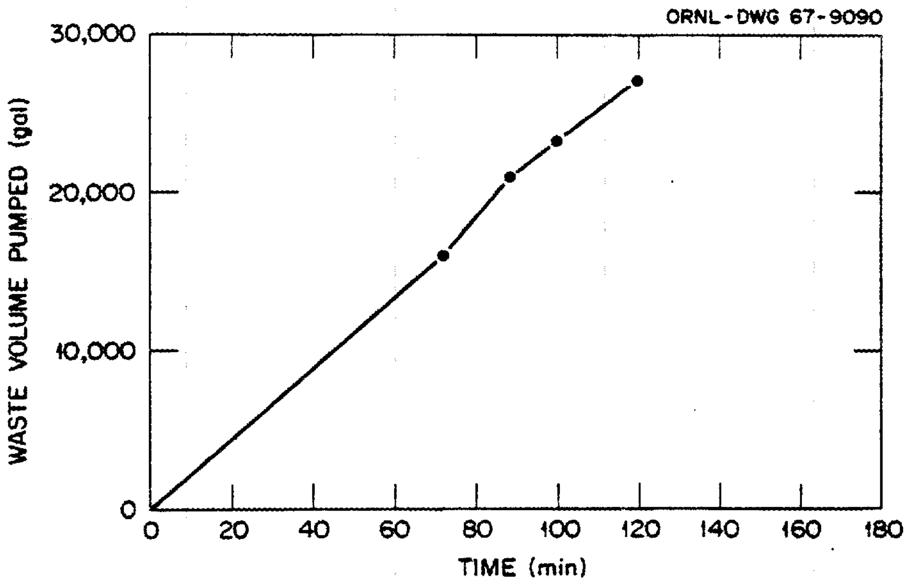

Fig. 7.4. Cumulative Volume Pumped, Injection 2.

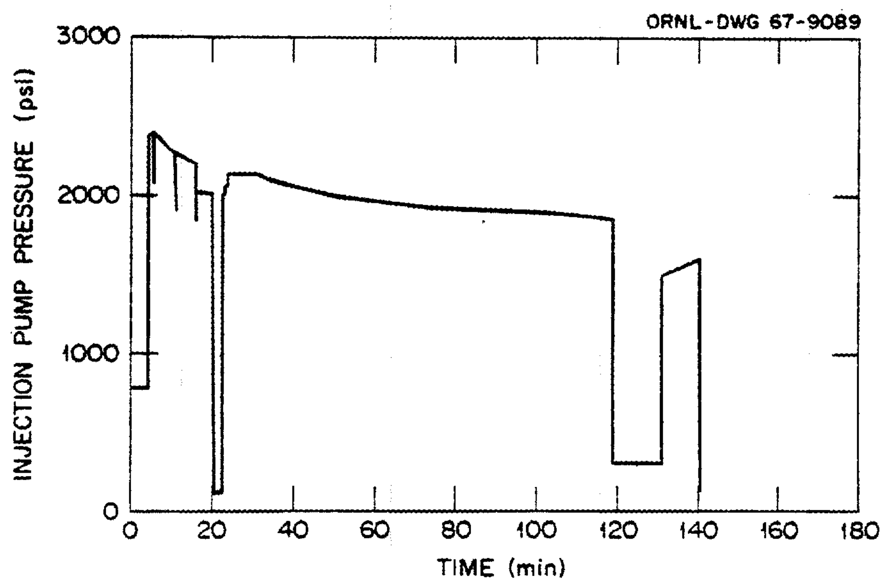

Fig. 7.5. Pumping Pressures, Injection 2. Measured on outlet of injection pump.

reading was 2 mr/hr. At the slurry sampler station, no reading above background was obtained. At the solids observation window on the operating platform the reading was $2\frac{1}{2}$ mr/hr.

At 11:04 AM, when approximately 8000 gal of waste had been pumped, the waste activity was detected in the cased observation well at a depth of 904 ft. After the initial appearance of the waste, it apparently channeled upward 30 or 40 ft alongside the well through the weak cement that had been used to cement the bottom 300 ft of the observation well.

This injection was planned to be run with a cement to liquid waste ratio of 5.5 lb/gal (slurry density, 13.5 lb/gal). In the course of the injection, it was found that this solids concentration was too low for the Densometer control system to operate effectively; manual control of the solids concentration was used throughout the run, with a consequent unevenness of the slurry density. This is shown in Fig. 7.6, which is a plot of the recorded slurry density. The average cement to liquid waste ratio maintained throughout the run was 5.87 lb/gal.

The injection was halted when the supply of blended solids was exhausted. The cement that had been stored separately was then mixed with water and injected. This was done to decontaminate the plant equipment prior to the washup operations. The plug of 20 bags of cement was then pumped down the well by the standby pump.

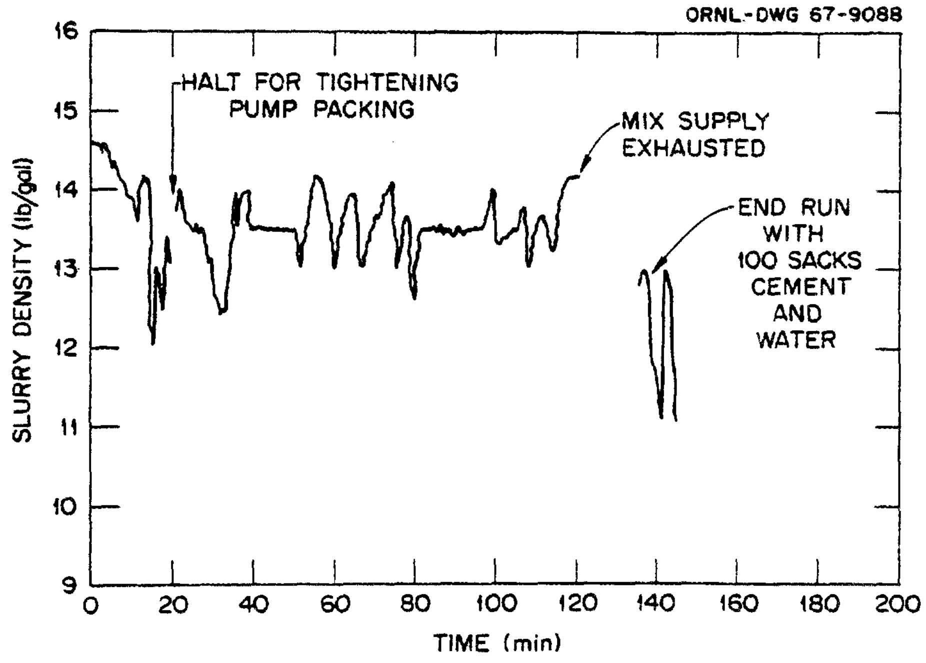

Fig. 7.6. Record of Solids-Liquid Mixing, Injection 2.

INJECTION 3

Preliminary Preparations

During the period between injection 2 and injection 3, a number of modifications were made to various parts of the fracturing plant. These modifications included the following items:

1. A power swivel was procured to eliminate the hazardous job of rotating the tubing string by hand during slotting. The swivel is powered by hydraulic oil from the Densometer pump.
2. A Sutorbilt rotary positive blower (type 6LXB) was installed to supply air to the air slides. This blower has a capacity of over 400 cfm at 3 psi pressure and thus eliminated the air supply difficulties experienced during the first two injections.
3. The inside of the cells was painted with white paint, more lights were installed, and glare shields were erected to make vision into the cells easier.
4. A Gadco dampener was installed on the injection pump discharge line to reduce pressure pulsations.
5. The concrete waste pit was cleaned of its accumulation of sand and grout. The discharge line from the valve rack was extended so that it would be as far as possible from the waste pump suction intake.

Twelve loads of solids were mixed. A total of 518,000 lb of cement, 10,300 lb of attapulgite, and 772 lb of retarder was blended over a four-day period and stored in the four bulk storage tanks. Bulk storage bins 1, 2, and 3 each contained about 135,000 lb of cement (and other materials in proportion); bulk storage bin 4 contained about 110,000 lb of cement.

Approximately 13,000 gal of synthetic 10X waste solution remained in the waste storage tanks after injection 2. This waste was mixed with 7500 gal of actual ORNL waste and about 15,800 gal of synthetic concentrated (10X) waste solution to produce 36,300 gal of solution. The activity of the solution averaged 0.0024 curie/gal.

The well was slotted at a depth of 912 ft on April 6, 1964, by circulating a slurry of sand and water through the jet tool for approximately 25 min at an average wellhead pressure of 3300 psi. A slotting jet with three $\frac{1}{4}$-in. nozzles was used instead of the jet with four $\frac{3}{16}$-in. nozzles used previously.

After slotting had been completed and the well had been backwashed, the formation was fractured. Breakdown pressure was approximately 2400 psi (wellhead measurement). A total of 1020 gal of water was injected at this time to establish that the formation had fractured sufficiently and to reduce the volume of water in the waste pit so that subsequent washup operations would not overfill the pit.

Injection

The injection was started at 11:40 AM, April 8, 1964. Two equipment malfunctions occurred during this run – the mixing jet was partially plugged, and the packing of the injection pump overheated. Neither malfunction was serious enough to require that the injection be terminated. The injection was continued until the supply of solids was exhausted at 3:14 PM. A total of 33,500 gal of waste solution was injected at an average rate of 195 gpm.

A plot of the volume of waste pumped during the injection is shown in Fig. 7.7. These volumes were obtained from the level readings of the waste tanks.

As each bulk storage bin was emptied of cement, the volume of waste that had been pumped to that time was determined from level readings of the waste tanks. These figures were used for a spot check of the accuracy with which the Densometer system was controlling the proportioning of solids and liquid. These checks indicated that the Densometer control was working well. A plot of the recorded slurry density is shown in Fig. 7.8.

Readings of the intensity of the direct radiation were taken during the run at several points. In the valve pit and immediately adjacent to the waste pumps, the reading was 20 to 40 mr/hr. At the slurry sampler station, the reading was 20 mr/hr. At the solids observation window on the operating platform, the reading was 1 mr/hr; the same reading was obtained at the other observation windows. Airborne contamination in the air withdrawn from the hopper and slurry tub was also measured, and no activity was found. No activity was detected on the hopper off-gas filter at the end of the run.

At 1:40 PM the operation of the mixer jet became erratic, the trouble being diagnosed as a partially plugged jet. The material that plugged the jet presumably came from waste tank T-1, which had just been valved on stream. Over a period of time, the jet was cleared by varying the operating conditions of the jet, thereby working the plug through the jet; it was not necessary to stop the injection.

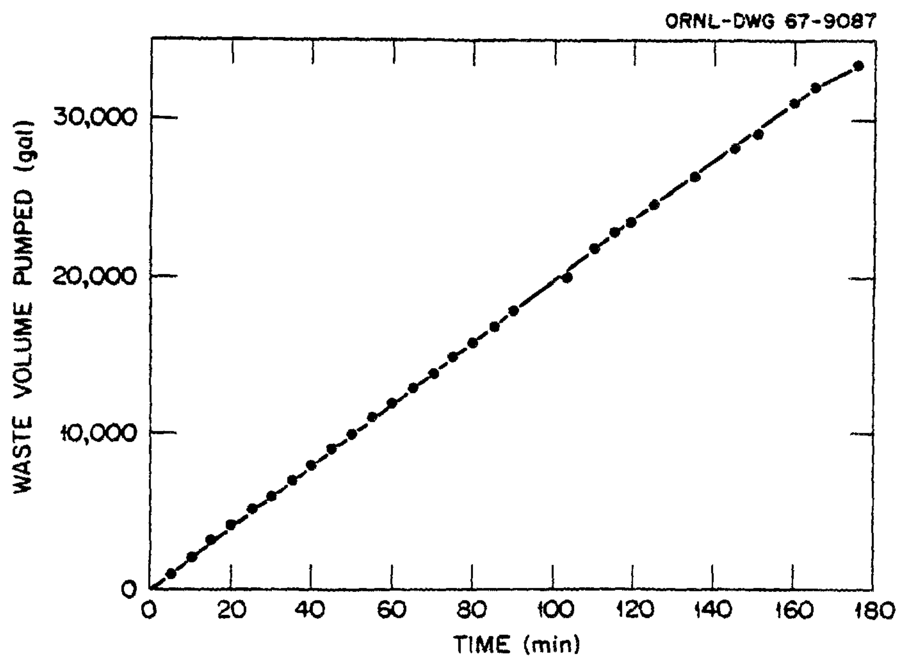

Fig. 7.7. Cumulative Volume Pumped, Injection 3.

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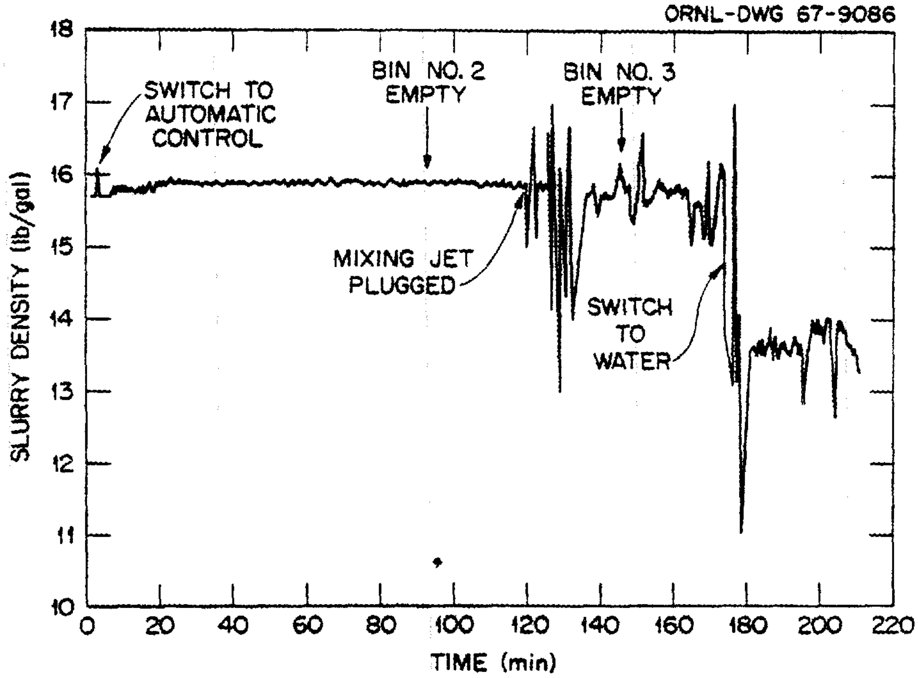

Fig. 7.8. Variations in Slurry Density, Injection 3.

At 2:25 PM the packing on the HT-400 injection pump was found to be overheating and smoking. An investigation revealed that the supply of oil used to lubricate the packing was exhausted. The oil supply was refilled, and the run was continued at a reduced rate. No evidence of improper pump operation was noted during the remainder of the run.

At 2:40 PM the volume of waste remaining in the waste storage tanks was 1000 gal in each tank; 33,500 gal had been pumped. At this time the injection was stopped temporarily, and the valving was switched so that water instead of waste solution was fed to the mixer – the purpose being to consume the remaining solids in the bulk storage bins and to partially decontaminate the equipment by pumping nonradioactive grout through it. Since a liquid with a different specific gravity was being used, a change in the Densometer setting was necessary. From a Densometer setting of 15.7 lb/gal, the setting was changed to 13.4 lb/gal instead of to the setting of 14.7 lb/gal that should have been used. As a result, during the last part of the run, a mix was injected that had a much lower concentration of cement than planned – 11.2 lb/gal instead of 14. A slurry volume of 10,000 gal was injected during this period. Subsequent laboratory tests indicated that a phase separation of 12% is probable with this mix. This suggested that free water might be found when this grout sheet was cored.

The injection ended at 3:14 PM, after a total of 65,000 gal of slurry had been injected. A plot of the injection pressure is shown in Fig. 7.2.

No indication of the grout sheet was detected in the observation well on the day of the injection or on the following day. On April 13, however, a weak indication was found at a depth of about 890 ft. Since the grout had almost certainly set by this time, this indication was probably caused by migration of water containing a small amount of activity.

Calculation of the ratio of solids to liquid of the mix that was injected during the run indicated that neither the Densometer readings nor the spot checks of the weight of cement consumed were a good indication of the actual ratio. The Densometer is subject to various inherent errors (such as air entrapped with the slurry), and the bins were seldom fully empty when the flow was switched. This being the case, the best available indication was a correction to the Densometer reading. The correction was based on the assumption that the Densometer error was constant. The calculation indicates that before the mixer jet plugged, the mix ratio was 13.3 lb of cement per gallon; from the time the mixer jet plugged until the end of the waste injection, the mix ratio averaged 12.95 lb/gal; during the water washup, the mix ratio averaged 11.2 lb/gal.

INJECTION 4

Preliminary Preparations

During the week between injection 3 and injection 4, several modifications were made to various parts of the fracturing plant. These modifications included the following items: (1) A new jet mixer was installed, one with two additional jet nozzles that could be rotated into position as needed, thus reducing the seriousness of the problem if a jet should become plugged. (2) Vibrators were installed on the bulk storage tanks so that they could be more completely emptied.

Eight loads of solids were mixed. A total of 381,000 lb of cement, 17,000 lb of attapulgite, and 381 lb of retarder was blended over a three-day period and stored in the four bulk storage bins. Bulk storage bin 1 contained about 94,000 lb of cement, bin 3 contained about 61,000 lb, and bin 4 contained about 90,000 lb.

Approximately 39,000 gal of actual intermediate-level waste solution was transferred to the site and mixed with the solution remaining in the waste storage tanks. Samples were taken of the waste solution in each tank. The activity of the solution averaged 1.3×10^{-3} curie/gal.

An attempt was then made to slot the casing at a depth of 900 ft. An excessive vibration of the tubing string developed, however, and the attempted slotting was stopped. Investigation showed that the injection pump was drawing air past the packing, thereby causing the vibration. The slotting operation was therefore postponed, pending repacking of the pump. The pump was partially disassembled for repacking on April 14. It was found at this time that misalignment and overheating had caused considerable damage to pistons, packing, seals, and other parts of the pump and that fairly extensive repairs would be necessary. The necessary replacement parts were ordered and arrived on April 17. At this time the pump was reassembled and tested.

The well was slotted at a depth of 900 ft by circulating a slurry of sand and water for approximately 25 min at a wellhead pressure of 2900 psi. Forty sacks of 20–40 mesh sand were used.

After slotting had been completed and the well had been backwashed, the formation was fractured. Breakdown pressure was approximately 3800 psi (wellhead measurement). A total of 2670 gal of water was injected at this time to establish that the formation had fractured sufficiently and to reduce the volume of water in the waste pit so that subsequent washup operations would not overfill the pit.

Injection

The injection was started at 8:16 PM, April 17, 1964. All major components operated satisfactorily, and the injection continued until the supply of solids was exhausted at 11:15 PM. Approximately 36,000 gal of waste was pumped at an average rate of 222 gpm. A plot of the volume of waste pumped during the injection is shown in Fig. 7.9. Both the volume indicated by the level readings of the waste tanks and the volume indicated by the gallon counter of the injection pump are shown.

As each bulk storage tank was emptied of cement, the volume of waste that had been pumped to that time was determined by level readings of the waste tanks. These figures were then compared to check the accuracy with which the Densometer system was controlling the proportioning of solids and liquid. These checks indicated that the Densometer control was working well. A plot of the recorded slurry density is shown in Fig. 7.10.

Density determinations made on samples of slurry taken at the fracturing plant early in the run indicated that the Densometer was indicating a greater density than was actually the case. Control was then switched to Densometer 2, which indicated a much lower slurry density. When control was thus switched to Densometer 2, a careful check of the valving was not made. As a result, a drain line was left open and some grout was pumped to the concrete waste pit before

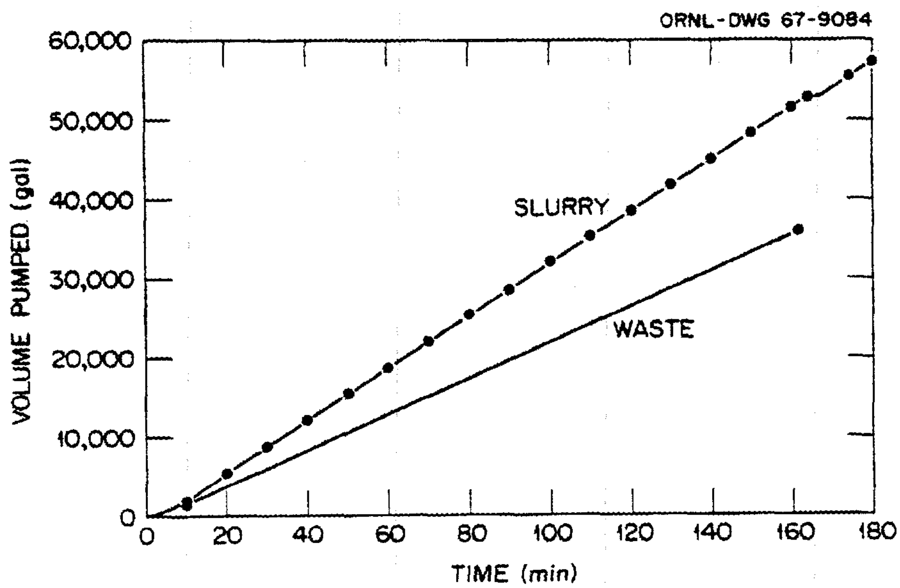

Fig. 7.9. Cumulative Volume Pumped, Injection 4.

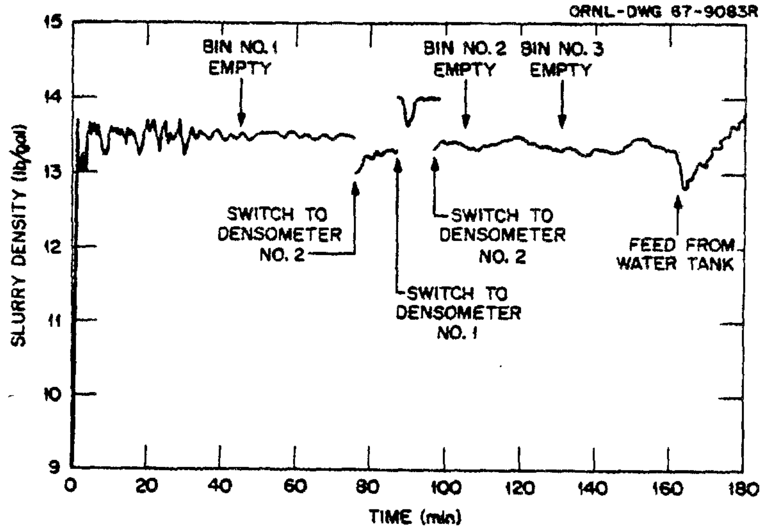

Fig. 7.10. Slurry Density, Injection 4.

the situation was discovered. The volume of grout thus lost probably did not exceed 300 gal. The mix density was controlled by Densometer 2 for the remainder of the injection.

At 9:05 PM, after approximately 15,000 gal of slurry had been injected, activity was detected in the observation well. The activity was found to be spread over about 30 ft of the well, with peaks of activity at depths approximately 10 ft apart.

At 11:00 PM, after approximately 36,000 gal of waste had been injected, the valves were switched to feed the plant from the waste pit. Approximately 500 gal of water was pumped from the pit, mixed with cement, and injected. This was done to reduce the liquid volume in the waste pit and thereby allow more freedom in subsequent washup operations. The valves were switched again to feed the plant from the water tank, and the injection was continued until the supply of solids was exhausted, at 11:16 PM. A plot of the injection pressure is shown in Fig. 7.2.

As was the case in injection 3, neither the Densometer readings nor the spot checks of the weight of clay and cement consumed were a good indication of the actual ratio of solids to liquid of the mix that was injected. The Densometer readings were erratic during the early part of injection 4. Because the vibrators helped to get each bulk storage bin more nearly empty, the spot checks were more reliable in injection 4.

The best available indication of the mix ratio that was injected is a corrected Densometer reading. Such a correction indicates that for the first 45 min of operation, the mix ratio was 9.42 lb of cement per gallon of waste; for the next hour, the ratio was 9.5; and for the final $1\frac{1}{4}$ hr, the ratio was 9.6.

INJECTION 5

Preliminary Preparations

During the period between injection 4 and injection 5, a number of modifications were made to the fracturing plant. These modifications included the following items:

1. The splash shield on the injection pump was extended and connected to the walls of the cell, thereby enclosing the parts of the pump that are regularly in contact with radioactive solution.
2. The solids sampler was replaced by an improved model.
3. A larger filter holder and a larger blower were installed to handle the hopper off-gas.
4. The vibrators on the bulk storage tanks were reconnected to a high-pressure air supply.

Fourteen loads of solids were mixed prior to the injection. A total of 723,000 lb of cement, 72,300 lb of attapulgite, 50,700 lb of Grundite, and 2170 lb of retarder was blended over a five-day period and stored in the four bulk storage tanks and the two blending tanks. Bulk storage bin 1 contained 157,000 lb of cement, bin 2 contained 157,000 lb, bin 3 contained 158,000 lb, bin 4 contained 159,000 lb, and the blending tanks each contained 46,000 lb.

Approximately 37,000 gal of ORNL's intermediate-level waste solution was transferred to the site and mixed with the solution remaining in the waste storage tanks. One tankful of this waste was thought to contain a significant quantity of ^{144}Ce, but an analysis of the solution in the tank showed a specific activity of only 0.026 curie/gal. (Subsequent events led to the conclusion that the ^{144}Ce had probably precipitated and settled in the tank and hence was not picked up in the sample.) The solution activity in the other two waste storage tanks averaged 0.003 curie/gal.

The emergency waste trench was lined with plastic sheet and filled with approximately 100,000 gal of synthetic waste solution.

A check of the injection well showed that the plug of the previous injection had been over-displaced and that the fracture used in this injection was still open. A new plug was mixed and pumped down the well to seal this fracture. The well was slotted at a depth of 890 ft by circulating a slurry of sand and water for 35 min at a wellhead pressure of between 3000 and 3700 psi. Forty sacks of 10–20 mesh sand were used.

After slotting had been completed and the well had been backwashed, the formation was fractured. Breakdown pressure was approximately 3800 psi (wellhead measurement). A total of 1700 gal of water was injected at this time to establish that the formation had fractured sufficiently.

Injection

For the planned injection approximately 1,000,000 lb of solids and 155,000 gal of waste solution were required. Since neither the waste storage tanks nor the bulk storage bins had sufficient capacity to store this quantity of materials, special procedures were used to fill the tanks and bins during the injection. The emergency waste trench was filled with synthetic waste solution, and the standby pump truck was used to pump the synthetic waste from the trench to the waste storage tanks. In addition, plant waste was pumped through the transfer line to the waste tanks during most of the run; approximately 12,000 gal was transferred in this manner.

About 850,000 lb of mixed dry solids were blended and stored in the storage bins prior to the injection. The remaining 160,000 lb that were required were mixed while the injection was in progress. As soon as the first bulk storage bin was emptied, the solids stored in the blending tanks were transferred to the empty bin. Seven truckloads of cement (315,000 lb) and the necessary amounts of attapulgite, Grundite, and retarder were then blended and transferred to the bulk storage bins while the injection was proceeding. A total of 137,000 lb of cement was charged to bin 1, 135,000 lb to bin 2, 90,000 lb to bin 3, and 45,000 lb to bin 1 a second time during the injection.

In previous injections, considerable difficulty in determining mix density resulted because the bulk storage bins were not, in fact, empty when flow was switched to another bin. To avoid such confusion in injection 5, particular care was taken to make sure each bin was empty when flow was switched.

The injection was started at 7:11 AM, May 28, 1964. All components of the facility operated satisfactorily, and the injection continued until the supply of solids was exhausted at 5:50 PM. Approximately 148,000 gal of waste was pumped at an average rate of 240 gpm.

A plot of the volume of waste pumped during the injection is shown in Fig. 7.11. The volume of slurry pumped can be found by multiplying the liquid volume by the factor 1.32. A plot of the injection pressure during the run is shown in Fig. 7.2.

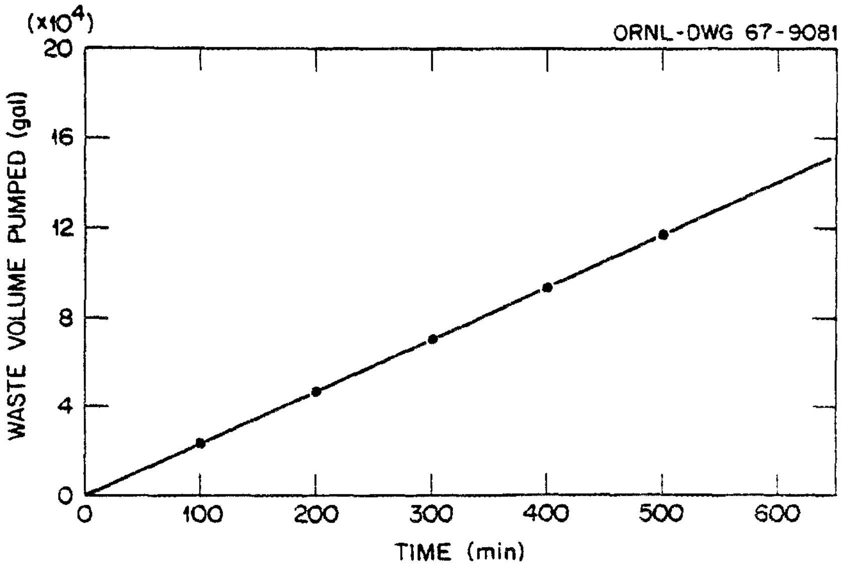

Fig. 7.11. Cumulative Volume Pumped, Injection 5.

As each bulk storage bin was emptied of cement, the volume of waste that had been pumped to that time was determined by level readings of the waste tanks. The volume of waste and the weight of cement consumed were used to determine the accuracy with which the Densometer system was controlling the proportioning of solids and liquid. These checks showed good correlation during the first part of the run but a progressively poorer correlation thereafter, probably as a result of partial plugging of the Densometers. A plot of the recorded slurry density is shown in Fig. 7.12.

In Fig. 7.13 is shown the average slurry density computed from the amounts of cement and waste consumed compared with the average slurry density measured by the Densometer.

Activity levels were considerably higher in this run than in any preceding run. Particularly high radiation readings were obtained when the waste solution was pumped from the waste tank containing the ^{144}Ce. These readings were much higher after the tank had been emptied and refilled than when the tank was being emptied the first time. Presumably the ^{144}Ce had precipitated and settled and was resuspended when the tank was refilled. No activity was detected in the hopper off-gas downstream from the filters, and no dose rate higher than 5 mr/hr was observed in any operating area.

At 5:30 PM, after 147,600 gal of waste had been injected, the run was halted temporarily, and 920 gal of water was pumped from the waste pit, mixed with solids, and injected. This was done to reduce the liquid volume in the waste pit so that more washup water could be used, if necessary. The injection was resumed, with water from the water tank being mixed with the remaining solids. The injection was ended at 6:50 PM, when the supply of solids was exhausted.

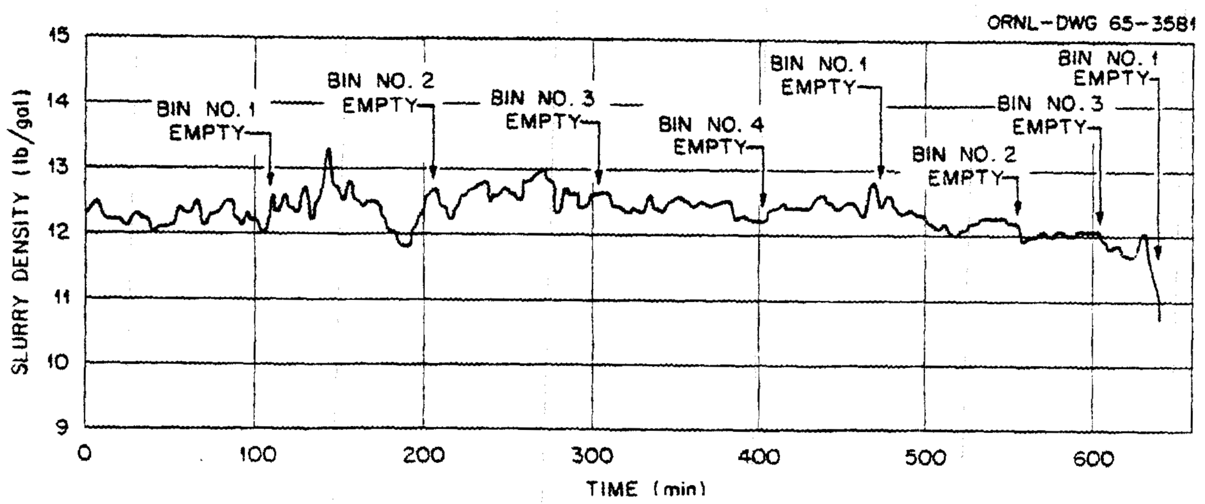

Fig. 7.12. Record of Slurry Density, Injection 5.

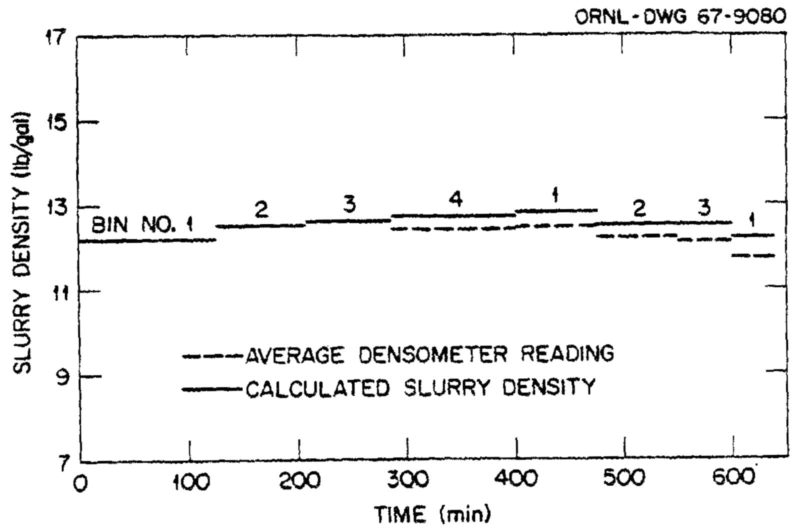

Fig. 7.13. Densometer Readings and Calculated Slurry Density, Injection 5.

RADIONUCLIDE RETENTION IN GROUTS

Following injection 5, four core holes were drilled to the top of the Rome sandstone to locate and obtain samples of the solidified grout (Fig. 7.14). The results of this drilling are given in Sect. 10.

Well S100 intersected injection 3 at a depth of 904.5 ft, or −118.4 ft mean sea level. This grout seam appeared in the core as a single layer about 0.35 in. thick. The seam flowed water slowly from December 9, 1964, when the flow rate was about 13.2 gal/hr, to January 11, 1965, when the flow rate was 3.7 gal/hr. At this time drilling was resumed. A sample of the water collected on December 14, 1964, gave the following analysis in parts per million: Cl^-, 36,500; Na^+, 31,100; NO_3^-, 28,600; Ca^{2+}, 2930; OH^-, 2000; SO_4^{2-}, 1620; Mg^{2+}, 380; Sr^{2+}, 350; CO_3^{2-}, 160; and HCO_3^-, <1.0. Radioactive materials in the water gave the following analysis in disintegrations per minute per milliliter, corrected for geometry: ^3H, 1620; ^{90}Sr, 150; and ^{137}Cs, 830. Gas which accompanied the water in very roughly equal volumes gave the following analysis in volume percent: N_2, 72.7; CH_4, 9.5; O_2, 0.63; H_2, <0.2; CO_2, 0.1; CO, 0.1; the balance of about 17% is probably hydrocarbons heavier than methane. Gas of similar composition had been collected from the Joy well before the casing was set and from several other wells at the site of the second fracturing experiment. The nitrogen is presumably air from which the oxygen has been removed, and the methane and other hydrocarbon gases come from the breakdown of seaweed trapped in the lower Conasauga shale when it was deposited.

The relatively large flow of water from the grout seam formed by injection 3 may possibly be explained as due to phase separation from the improperly proportioned grout pumped during the last 30 min of the injection. The high content of sodium chloride results from leaching of

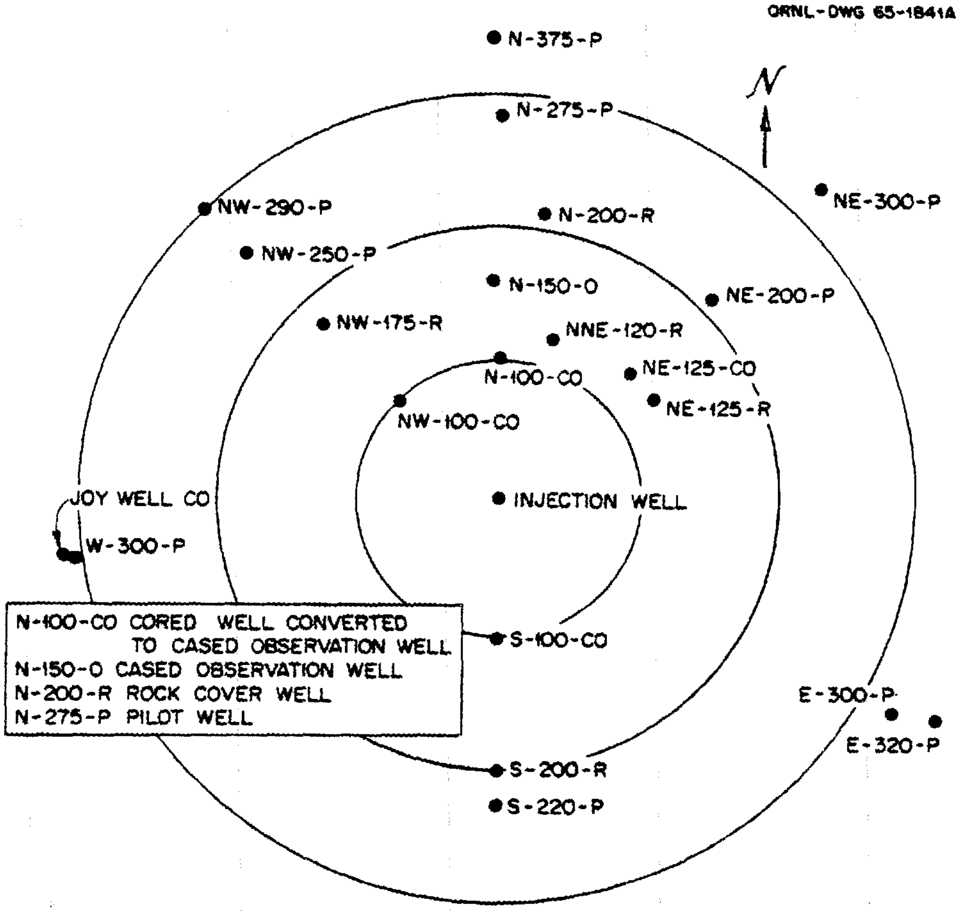

Fig. 7.14. Pattern of Observation Wells Predrilled to a Depth of Between 500 and 600 ft.

the red shale, and the high caustic content of the water from the high caustic content of the 10X synthetic waste used for this injection.

In Table 7.2 are shown leachability data on grout materials prepared (1) with simulated waste spiked with actual ORNL waste (laboratory mix), (2) from samples taken at the fracturing plant during injections 3, 4, and 5 (plant slurry), and (3) from grouts recovered in the core drilling program (cored grout). The laboratory mix was cured for approximately 12 to 14 months; the plant slurries and cored grouts had cured for about 10 months, that is, from the time of the actual injections. Since the thin grout sheets in the recovered cores were not of uniform geometry, as the samples from the cube molds prepared in the laboratory were, all three types of grout were ground and sieved, and only those particles passing a 60-mesh screen were used in the tests (see Chap. 5) because of the enormous increase in surface area exposed. Leaching of the 60-mesh particles was carried out in plastic bottles containing 1 g of solids per 100 ml of distilled water.

Table 7.2. Comparison of Radionuclide Leaching of Grouts from Laboratory Simulated Waste, Plant Slurry, and Core Samples

Values listed are cumulative percentages of original activity leached

Leaching Time (hr)	Injection 3			Injection 4			Injection 5		
	Laboratory Mix	Plant Slurry	Cored Grout	Laboratory Mix	Plant Slurry	Cored Grout	Laboratory Mix	Plant Slurry	Cored Grout
1	13.5	16.83	4.01	0.95	3.27	0.39	0.13	0.08	0.04
4	15.68	17.01	4.40		4.08	0.33			
24	15.61	17.36	4.66	2.54				0.10	0.05
72					7.36	0.35	1.32	0.21	0.06
120	16.35	18.05	5.00	3.33	8.08	0.30	1.62		
260	17.65	18.61	8.22	3.80	8.40	0.16	1.77	0.27	0.05
336	17.90	18.73	9.06	3.73	8.30	0.23	1.95	0.28	0.06
504	18.75	19.60	8.97	3.14	8.52	0.19	2.14	0.30	0.06

The data in Table 7.2 indicate that the highest leach rates occurred in the mix used in injection 3. Considering the three laboratory mixes, one observes that leachability increases in the order of the respective injections, 3 > 4 > 5. This is accounted for as follows. Injection 3 was of 10X waste, and the mix contained no illite; the high salt content prevented attapulgite from adsorbing radioactivity, particularly the ^{137}Cs which predominates in actual ORNL intermediate activity waste. Low-salt-content waste solution, 1X, was used in injection 4; in this case the lack of competition for fixation sites greatly improved the attapulgite's retention of radiocesium. The mix for injection 5 contained 1X waste and illite, and the retention of ^{137}Cs was increased by about 30%. The retention of ^{137}Cs by illite is high because illite is highly selective for sorption of radiocesium whereas attapulgite is not, losing its capacity for sorption of this radionuclide as the salt concentration is increased.

It is seen in Table 7.2 that the retention of radionuclides by the grouts formed in the disposal formation (cored grout) was better than that by the grouts prepared in the laboratory (plant slurries and laboratory mixes). Perhaps the improvement comes from the setting and curing under pressure. Setting under pressure develops a grout of slightly higher density and therefore of lower porosity and surface area available for leaching. Cored grout from injection 5 was the best in retaining radionuclides; analysis of the leachate revealed that the activity was primarily ^{144}Ce.

These results were very encouraging and suggested a continuing program of mix development with emphasis on the design of mixes with improved radionuclide retention characteristics.

8. Experimental Injections, 6 and 7

The second series of two experimental injections was planned (1) to determine the underground behavior of low-solids-content slurries containing a cheaper substitute (pozzolan) for portland cement, (2) to evaluate the performance of a mass flowmeter for solids/liquid proportioning – a device that would continuously weigh the dry solids being used and thereby make possible a more precise control of the ratio of solids to liquid than had been possible with the Densometer, and (3) to evaluate laboratory results of phase separation in the low-solids-content slurries (see Chap. 5) by measuring the flowback of water and/or waste from injected grout in the fracture. An objective of secondary importance was to test the results of two injections into the same slot in the well casing.

Prior to injection 6, laboratory tests with low-solids-content mixes had provided considerable evidence that phase separation could occur before or after setting, depending on the chemical composition of the waste and on the proportions of attapulgite and delta gluconolactone (DGL) in the solids blend. It was necessary therefore to assess this problem in the field, conditions being considerably different in the fracturing plant, in the injection well, and in the fracture than in our laboratory testing equipment. We reasoned that phase separation could be assessed by measuring and analyzing the flowback of water or waste from the injection well, after the injection had been completed and the injected slurry had had time to set, by leaving open the slot at the bottom of the well and then later opening the valve at the wellhead. Thus, if phase separation had not occurred, only a minimal volume of liquid would be expected to flow back, representing essentially the small amount of contaminated water pumped into the fracture at the end of the run following cleanup; if phase separation had occurred, that small amount of contaminated water plus some unknown amount of waste solution would be expected to flow back.

Volumes of about 100,000 gal were planned for both injections, this being the maximum volume that could be injected without requiring cement delivery during the injection. As in injection 5, the 60,000 gal of waste solution required in excess of the capacity of the waste storage tanks (40,000 gal) was to be synthetic waste (nonradioactive) made up at the Y-12 plant beforehand and transferred to the emergency waste trench. This solution would be pumped to the storage tanks as these tanks were emptied during the injection operation.
For injection 6, a mix of water and dry solids was to be used for the first 15 min of the injection so that the initial performance of the mass flowmeter could be evaluated and any necessary corrections made before the system became contaminated by waste solution. A similar mix was to be used the last 15 min of the injection to decontaminate the equipment.

WASTE COMPOSITIONS AND MIX FORMULATIONS

Waste Compositions

Table 8.1 lists the chemical and radionuclide contents of the waste solutions used in the two injections. The waste solution for injection 6 was planned to have approximately three times the concentration (3× waste) of dissolved salts in normal ORNL intermediate-level waste. Approximately 30,000 gal of actual waste solution containing about 1900 curies of ^{90}Sr and ^{137}Cs was transferred to the waste storage tanks. This waste was mixed with 10,000 gal of 10× synthetic waste solution, agitated, and sampled. Chemical analysis of the solution showed it to be approximately 3× waste (Table 8.1). Samples of the synthetic waste in the emergency trench indicated chemical concentrations somewhat less than those of 3× waste, probably due to inadequate mixing and dilution by rainfall.

Table 8.1. Chemical and Radionuclide Content of Waste Solutions Used in Injections 6 and 7

	Injection 6	Injection 7	
	(Tanks and Trench)	Tanks	Trench
Chemical concentration (*M*)			
Sodium hydroxide	0.69	0.17	0.04
Sodium nitrate	1.15	0.63	0.10
Ammonium sulfate	0.11	0.06	0.002
Aluminum sulfate	0.08	0.04	0.004
Sodium carbonate	0.08	0.04	0.011
Radionuclide content (curies)			
^{90}Sr	330	492	
^{137}Cs	1562	3358	
^{106}Ru	2	2	
^{60}Co	1	14	

The waste solution for injection 7 was meant to be 1.25× waste. About 36,000 gal of actual waste was transferred to the waste storage tanks. This waste contained 14 curies of ^{60}Co, which had been added as a tracer to aid in future identification of the grout sheet(s) of injection 7 if such identification should prove to be difficult. This waste solution was mixed with 5000 gal of concentrated synthetic waste solution, agitated, and sampled. The chemical concentration was approximately that of 1.25× waste; radiochemical analyses indicated 1828 curies of ^{137}Cs and 3.5 curies of ^{60}Co in tank 1, 906 curies of ^{137}Cs and 5.5 curies of ^{60}Co in tank 2, and 624 curies of ^{137}Cs and 5.0 curies of ^{60}Co in tank 3. About 40,000 gal of water was run into the emergency waste trench and thoroughly mixed with the 3× synthetic solution already in the trench. The trench was sampled at various locations and depths; samples showed no evidence of any concentration gradient and indicated that the chemical concentration of the solution was very nearly that of water (see last column in Table 8.1).

In spite of the lack of control of waste compositions in the tanks and in the emergency trench, we were able to formulate the appropriate mixes because the analytical data were obtained before the dry solids were blended.

Mix for Injection 6

This mix was developed as a low-cost setting mix containing pozzolan as a partial substitute for portland cement. The slurry had the following composition and properties:

Composition	3× waste prepared from 30% synthetic 10× waste and 70% normal ORNL waste with 400 ppm TBP
	2.0 lb type II cement per gallon of waste
	2.5 lb Kingston fly ash per gallon of waste
	0.9 lb attapulgus 150 per gallon of waste
	0.5 lb Grundite per gallon of waste
	0.003 lb DGL per gallon of waste
Density	11.7 lb/gal
Volume	1.28 gal per gallon of waste
Viscosity	7 poises
Water separation	0 before and after setting
Fluid loss	197 cc/30 min using 100 psi test
Pumping time at 89°F	12 hr 50 min
Compressive strength	150 psi after 14 days at 80°F
Materials cost	5.9 ¢/gal

Although phase separation is discussed more fully later in this chapter, it should be noted here that the water (phase) separation reported for all mixes for injections 1 through 6 was determined on slurries prepared by the standard API technique of adding the solids in 15 sec while stirring at "slow" speed and then stirring for 35 sec at "high" speed in a Waring Blendor.

Mix for Injection 7

Two different blends were used in this injection. This became necessary when we discovered that the dry solids blend specified for 1.25× waste "flash set" with the waste in the storage tanks. Fortunately, this blend did form an acceptable slurry when mixed with the less-concentrated synthetic waste from the emergency trench. Hence, this blend (stored in bins 1 and 2) was used with the trench waste. This slurry had the following composition and properties:

Composition	0.3× waste prepared in the emergency trenches with 400 ppm TBP
	3.6 lb type II cement per gallon of waste
	2.9 lb Kingston fly ash per gallon of waste
	0.9 lb attapulgus 150 per gallon of waste
	0.5 lb Grundite per gallon of waste
	0.005 lb DGL per gallon of waste
Density	12.0 lb/gal
Volume	1.40 gal per gallon of waste
Viscosity	5 poises
Water separation	1% before setting; 0 after setting
Fluid loss	Not determined
Pumping time	Greater than 6 hr at 89°F
Compressive strength	Not determined
Material cost	7.5 ¢ per gallon of waste

The blend used with the waste in the tanks (1.25×) was stored in bins 3 and 4. This slurry had the following composition and properties:

Composition	1.25× waste with 400 ppm TBP
	1.8 lb type II cement per gallon of waste
	3.7 lb Kingston fly ash per gallon of waste
	0.9 lb attapulgus 150 per gallon of waste
	0.5 lb Grundite per gallon of waste
	0.007 lb DGL per gallon of waste
Density	11.7 lb/gal
Volume	1.38 gal per gallon of waste
Viscosity	5 poises
Water separation	0 before and after setting
Fluid loss	Not determined
Pumping time	Greater than 6 hr at 89°F
Compressive strength	Not determined
Material cost	6.2 ¢ per gallon of waste

The flash setting with tank waste was overcome by using less cement and more DGL in the formulation.

Figure 8.1 shows the variation in slurry density as a function of the solids content of the slurry. For injection 6, a solids feed rate of 6.0 lb per gallon of waste was specified, which corresponded to a slurry density of 11.70 lb/gal. The latter specification was required for controlling the solids to liquid ratio with the Densometer, and the former specification was required for adjusting the mass flowmeter.

For injection 7, two blends were prepared, and it was necessary to specify which storage bins were to be used with a given waste. For tank waste, solids from bins 3 and 4 were to be used at a feed rate of 7.0 lb/gal and a slurry density of 11.75 lb/gal. For trench waste, solids from bins 1 and 2 were to be used at a feed rate of 8.0 lb/gal and a slurry density of 12.0 lb/gal.

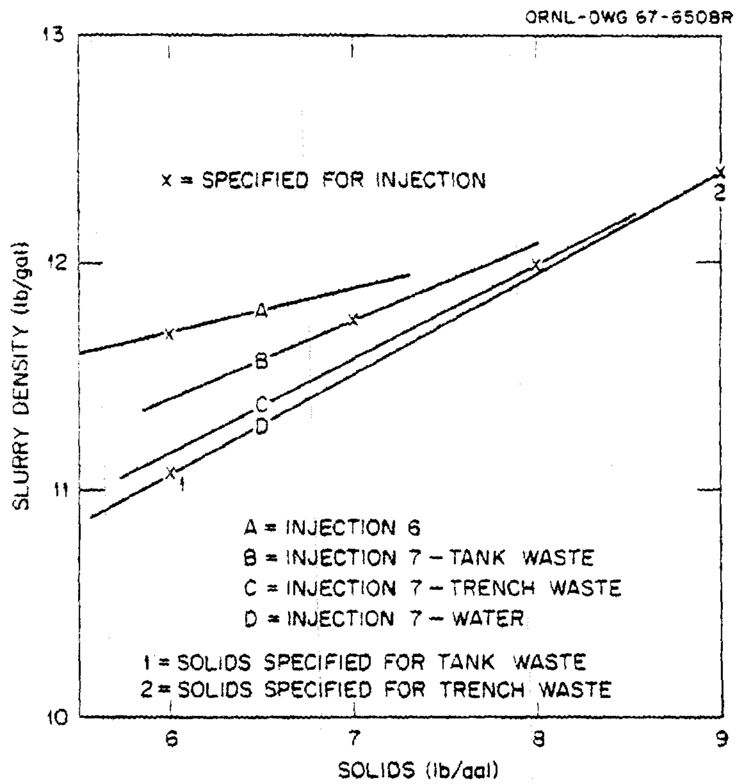

Fig. 8.1. Variation in Slurry Density as a Function of the Solids Content of a Slurry.

INJECTION 6

Plant Modification and Preparation

In the interval between injections 5 and 6, the major modification to the fracturing plant was the installation of a Halliburton mass flowmeter and associated equipment. The mass flowmeter is a device that will continuously weigh the solids passing through it, integrate this reading with a liquid flow rate measurement, and give a direct reading of the relative weights of solids and liquid that are being mixed to form the slurry. In preliminary tests this device had given a much more sensitive indication of the solids to liquid ratio than the Densometer system previously used. The arrangement of the mass flowmeter in the mixing cell is shown in Fig. 8.2.

Other modifications included the addition of supplemental shielding on the wall of the mixing cell facing the operating platform, a modification in the sampler to reduce the likelihood of plugging, and a minor change in the vent piping. Since constant observation of the hopper was not necessary with the use of the mass flowmeter and since it was desirable to reduce the radiation exposure of the operators, the window (Fig. 6.14) between the operating

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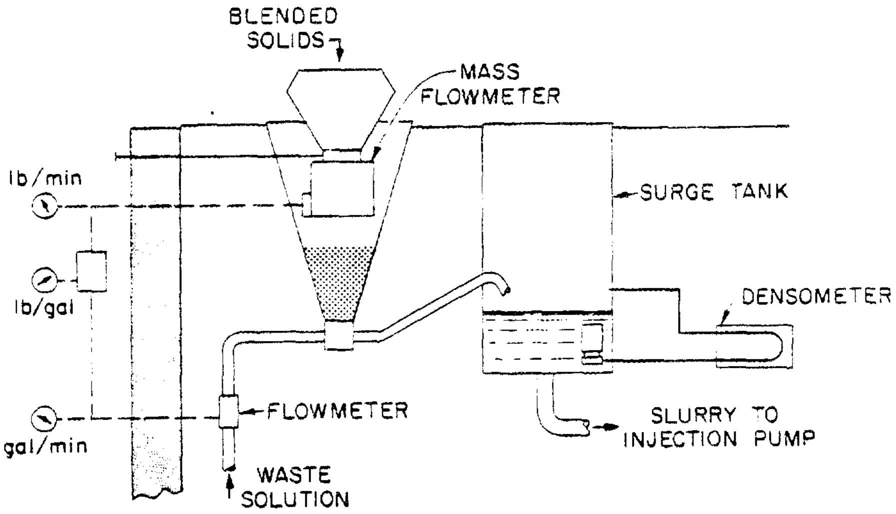

Fig. 8.2. Arrangement of the Mass Flowmeter in the Mixer Cell.

platform and the mixer cell was closed with lead bricks. The Plexiglas window in the mixer hopper was replaced with sheet metal.

The procedure for proportioning the mix for injection 6 was determined by the availability of a scale large enough to weigh loaded transporter trucks. A pneumatic transporter truck was loaded with fly ash at Kingston and driven to the cement plant at Knoxville. An empty transporter was parked on the cement plant scales, and fly ash was blown from the full truck to the empty one until the desired weight had been transferred. Cement was then added to the truck on the scales until the cement and fly ash in the truck were in the correct proportions. This load was then delivered to the hydraulic fracturing plant, and a second load was blended. Usually, three loads of proportioned cement and fly ash could be obtained from one load of fly ash. At the hydraulic fracturing plant, the cement and fly ash were blown from the transporter to a "P" tank; the attapulgite, Grundite, and retarder were added by means of the "bazooka." The load in the P tank was then blended and stored in a bulk storage bin.

The solids were blended over a five-day period and stored in the four bulk storage bins and the two blending tanks. During the loading of the cement into the transporters, an inexperienced operator was confused by the procedure and added too much cement to the trucks. This error was detected only after one of the bins was fully charged and a second bin partially charged. To correct the proportion of cement in the partially filled bin, the remainder of the mix was made with reduced cement content, and the bin was aerated to mix the entire content. The solids for the two remaining bins were blended according to specifications. The total was 520,600 lb of solids plus an unknown amount of excess cement in one of the bins.

Slotting and Injection

The injection well was slotted at a depth of 880 ft on May 18, 1965. Breakdown pressure was approximately 5000 psi (wellhead measurement). A total of 760 gal of water was injected at this time to establish that the formation had fractured sufficiently.

The injection was started at 9:30 AM, May 19, 1965. Almost immediately after startup, it became evident that the cement was not flowing as expected – the mass flowmeter indicated a feed rate of about 5 lb/gal, and the Densometer indicated a maximum slurry density of 10.8 lb/gal. The correct readings should have been 6.0 lb/gal and 11.7 lb/gal respectively. After 2570 gal of slurry had been pumped the injection was stopped to determine the cause of the trouble. The valve beneath bin 1 was found to be clogged with cement scale. The valve was cleared and the injection restarted. Again it became evident that the mixing was not normal; the flowmeter gave erratic readings, and the Densometer indicated a fluctuating density. The injection was stopped after a total of 4420 gal of waste had been pumped. The well, pump, and surge tank were washed clear of slurry, and a wiper plug was pumped down the well and overflushed. This ended what is called injection 6A (Fig. 8.3).

Investigation revealed that either the mixer or the hopper had become plugged and that the dry solids had filled the hopper and overflowed through a vent line to the surge tank and through the valve handle opening into the mixer cell, filling the mixer cell with dry solids and slurry to a height of about 3 ft. Also the solids in the mixer cell were contaminated.

Cleanup and Modifications

The solids in the mixer cell were washed to the cell drain by water hoses operated from the cell roof. The solids-water slurry was drained to the waste pit, and from there it was pumped back to the surge tank and down the injection well for disposal. A total of 18,800 gal of wash water was pumped into the well in this manner.

The mixer bowl was disconnected and found to be clear; the plugging was suspected to be in the hopper. After the packed and hardened cement was removed from the hopper, the accumulator tank was disconnected, and examination of the mass flowmeter revealed that a plastic cone about 12 in. in diameter had come loose. The cone had fallen into the hopper and caused the plugging.

Since repairs to the mass flowmeter would require several days, it was decided to continue the injection without repairing the flowmeter; control of the proportioning would be by the Densometer as in previous runs. It was further concluded that the large volume of waste water that had been pumped into the formation would make flowback measurements meaningless; hence it was decided to plug the slot and to cut a new slot and initiate a new fracture.

The accumulator tank was replaced in the mixer hopper. Screens made of $\frac{3}{4}$-in.-mesh woven wire were cut and inserted in the air slides from the storage bins as a precautionary measure to keep solids from entering the system.

Reslotting and Injection 6B

The original slot at 880 ft was plugged, and a new slot was made at 872 ft. The well was pressurized, and breakdown occurred at approximately 3500 psi. A total of 820 gal of water was pumped to develop the fracture (Fig. 8.4).

The injection was resumed on May 22, 1965. Within 10 min after startup, the flow of solids had stopped. Switching to a second and a third storage bin did not eliminate the problem; hence the injection was stopped, and the screens that had been placed in the air slides were removed. The screens were found to be plugged with agglomerated solid particles. The injection was then resumed without the screens.

For approximately an hour the operation was smooth; then the pressure indicator on the injection pump showed that a pressure fluctuation was occurring in the high-pressure system. This fluctuation increased progressively, and it was decided to halt the injection after 3½ hr of operation to check the pump and valves and to clear the air slide from bin 4, which was plugged.

The air slide from bin 4 was cleared of agglomerated solids. The pump was found to have a badly eroded valve. Evidently the valve had not been seating properly, and the flow of slurry at high pressure past the valve seat had caused the erosion. The valves were replaced and the injection resumed.

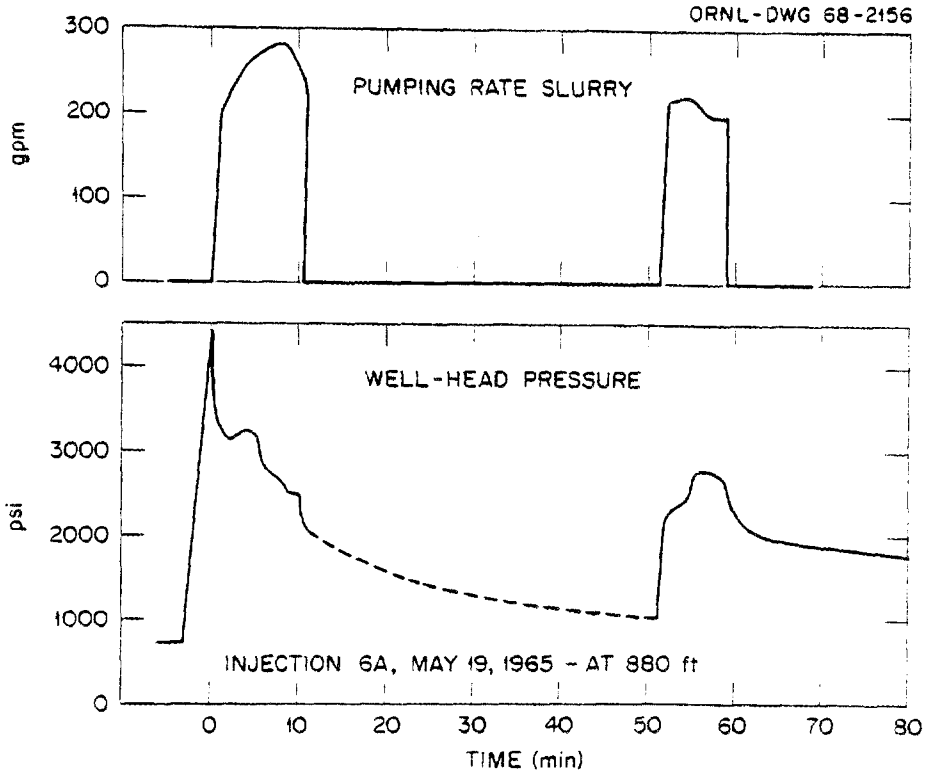

Fig. 8.3. Injection Pressure and Injection Rate During Injection 6A.

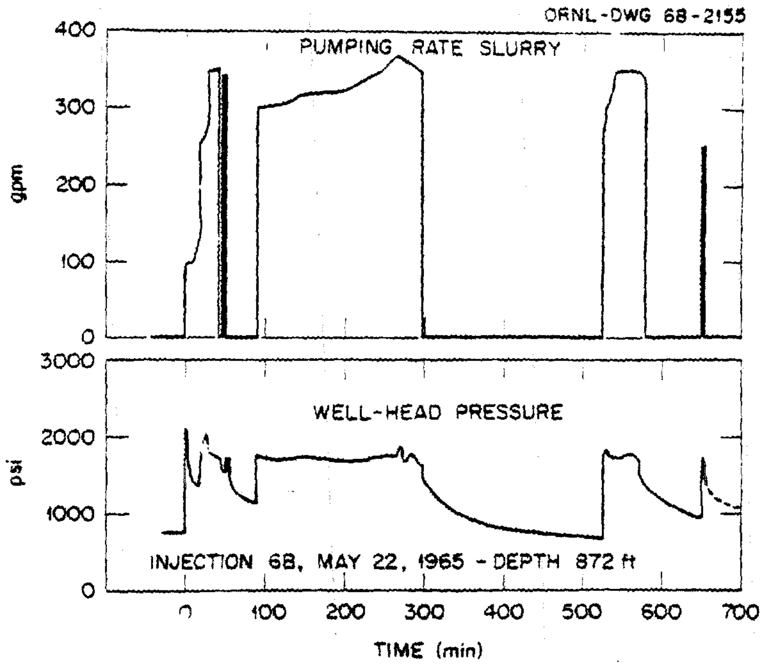

Fig. 8.4. Injection Pressure and Injection Rate During Injection 6B.

The injection was continued for 45 min, when a leak was observed in the wellhead cell. The injection was halted, and the standby unit was connected to the high-pressure piping manifold and used to pump water down the annulus and out the slot. Having located the leak at the connection between the plug container at the wellhead and the connecting piping, we opened the master valve and cleared the grout remaining in the central tubing string. After the well was cleared, the pump, the surge tank, and the piping manifold were washed. The wellhead cell was cleared first with hosing from the roof hatch and then with hosing from the inside of the cell by a man in an air suit. In this manner, contamination in the wellhead cell was reduced sufficiently so that the plug container could be removed from the wellhead and a direct connection made between the wellhead and the high-pressure manifold. About 2000 gal of water was then pumped down to clear the tubing and terminate the injection. The total volume of waste pumped during the injection was 64,000 gal. The total volume of slurry injected in 6B was 92,800 gal.

Cleanup and Maintenance

One of the heads of the injection pump was replaced with a new one. The pump was repacked, and new Chiksan fittings were installed on the high-pressure discharge. The fittings at several locations in the high-pressure manifold were checked for incipient fractures; none were found.

A considerable amount of solids that had been left over from injection 6 was found in bin 4 and removed. The other bins and the P tanks were checked and cleaned.

The surge tank was found to contain a great deal of set cement that had apparently gotten into the tank as a dry solid and had subsequently been wetted. The caked cement was about 1 ft deep in the tank and filled the drain lines for a distance of several feet. We have been unable to propose a reasonable explanation of how the dry solid got to the surge tank without going through the mixer hopper and leaving traces of its passage. The cement was chipped and scraped out of the tank and drain lines, and a hydrochloric acid solution was circulated through the system to complete the cleaning job.

The concrete waste pit had been filled with cement in the cleanup operations of injection 6. Another pit was constructed immediately adjacent to the existing pit, and the various suction and drain lines were rerouted to the new pit. The suction line from the waste pit to the waste pump was found to be plugged with cement and was replaced.

The top was removed from the wellhead cell to simplify the job of decontamination. The cell and the cell top were decontaminated, the grating on the bottom side of the cell top was covered with welded metal sheets to make future decontamination easier, and the cell top was reinstalled. All the cell interiors were repainted.

The mass flowmeter was reinstalled in the mixer hopper, and the system was checked. A calibration run had been made in Duncan with the sensing cone that had been lost in injection 6. It was not thought feasible to make another calibration run with the new cone; instead, it was planned to check the mass flowmeter readings against the weights of solids in the bins during the next injection and correct the mass flowmeter readings to make them agree – calibrate on the run, as it were.

Flowback from Injection 6

The wellhead valve was closed as usual when injection 6 was terminated abruptly on May 22, 1965. The valve remained closed until June 1, at which time the injected grout (92,800 gal) in the fracture produced through the slot at 872 ft had had more than enough time to set. On June 1, the valve was opened partially to allow fluid to flow back up the well at a rate of approximately 4 gpm; the wellhead pressure prior to the start of flowback was 350 psi. Flowback continued in this manner for 8 days, until the valve could be opened fully (June 9). Following this, the rate of flowback decreased rapidly over the next two weeks, as shown in Fig. 8.5. Beginning on June 22, the well was shut in for a period of 9 days. The valve was then reopened (July 1), and fluid continued to flow back at an ever-decreasing rate for the next 30 days. Sixty days beyond the date of the initial opening, when the flow rate had dropped to about 0.2 gpm, the valve was closed and flowback measurements were stopped. All of the fluid flowed back was collected in a calibrated tank, and samples were taken twice a day for the first week and analyzed; thereafter, the sampling frequency was reduced to once a day until the end of the observation period.

The rate of flowback with time and the accumulated volume are plotted in Fig. 8.5. A total of 17,000 gal of fluid flowed back during the 60-day period. Considering the 64,000

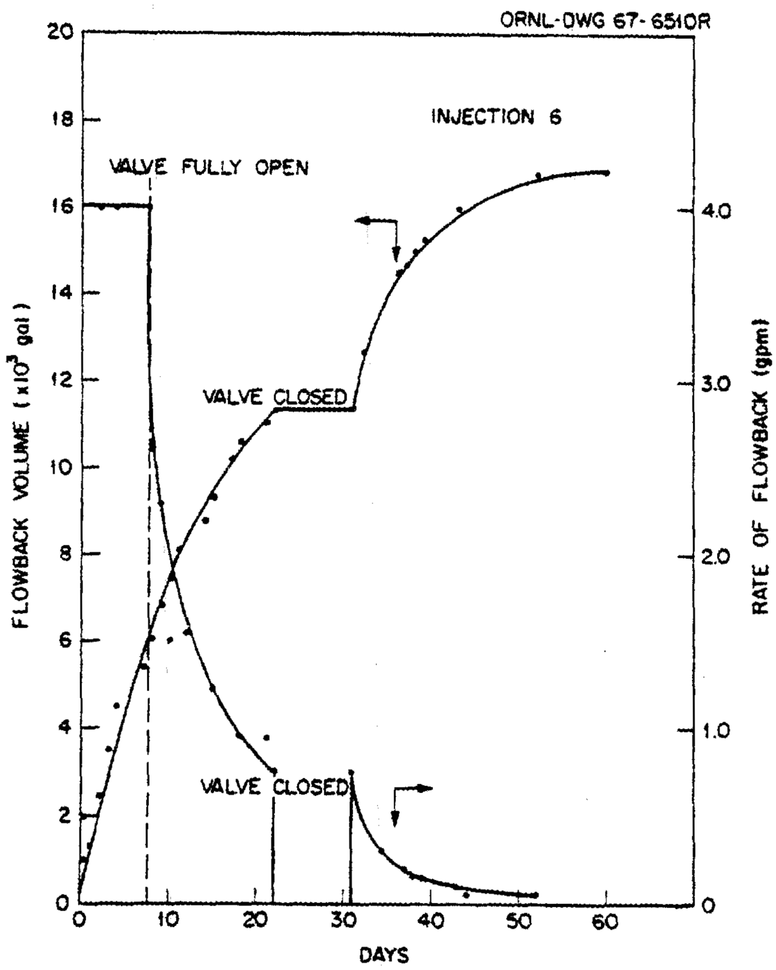

Fig. 8.5. Flow Rate and Cumulative Volume of Flowback with Time, Injection 6.

gal of fluid injected, this amount of flowback would indicate that phase separation in the slurry approximated 27% by volume. This value for phase separation may be unrealistic, however, in view of the many difficulties encountered during injection 6.

Conductivity and pH measurements were made of the samples taken during flowback. Conductivity was measured with a type RC conductivity bridge, and the readings were corrected to 24°C. The pH measurements were made with a standard Beckman pH meter. Results of these measurements are shown in Fig. 8.6. The data show that the conductivity of the flowback fluid rose rapidly and approached an equilibrium value. Samples taken after the 32d day showed lower conductivity values than those taken prior to the nine-day shut-in. The pH of the flowback fluid decreased with time; two samples taken after the well was shut in had higher pH values than the samples taken immediately before shut-in, but the trend was a definite decrease with time.

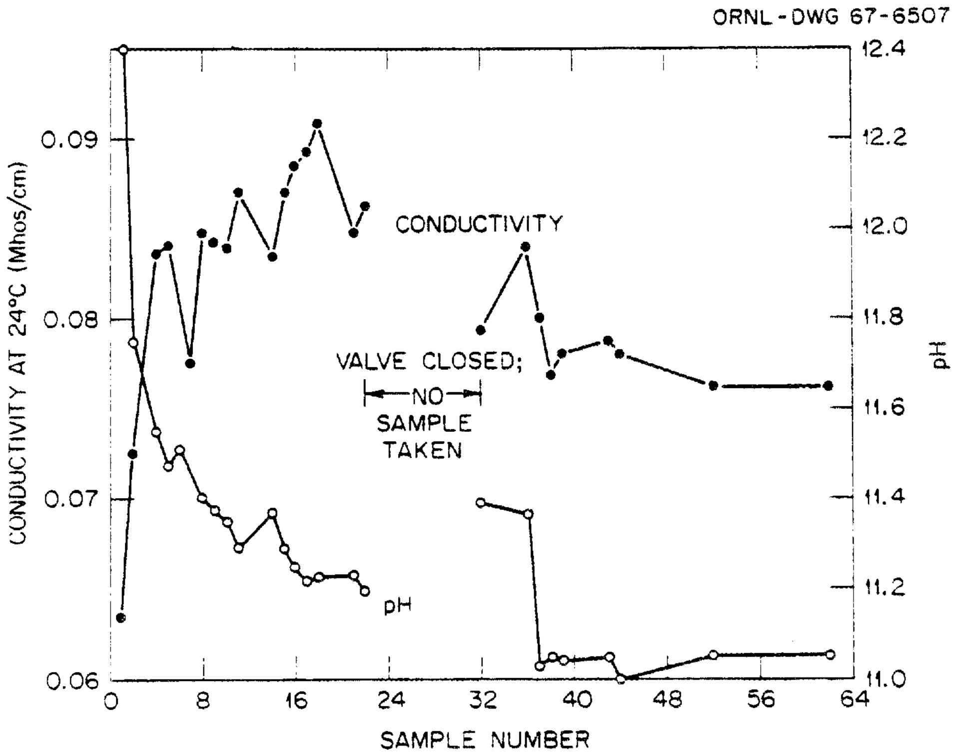

Fig. 8.6. Conductivity and pH Measurements of Flowback, Injection 6.

Table 8.2. Chemical and Radiochemical Composition of Flowback from Injection 6

Sample No.[a]	Chemical Concentration (*M*)						Nuclide Concentration (dis min^{-1} ml^{-1})			
	Na^+	Ca^{2+}	Cl^-	NO_3^-	SO_4^{2-}	CO_3^{2-}	^{137}Cs	^{90}Sr	^{106}Ru	^{60}Co
							$\times 10^4$	$\times 10^4$	$\times 10^4$	$\times 10^4$
2	0.78	0.027	0.47	0.30	0.006	0.006	6.20	4.40	0.22	~0.01
3	0.95	0.050	0.71	0.35	0.011	0.41	4.65	2.89	0.03	0.02
9	0.95	0.056	0.77	0.33	0.009	0.41	4.55	3.10	0.03	<0.006
16	1.07	0.065	0.84	0.31	0.008	0.03	3.63	2.82	0.00	<0.001
22	1.01	0.064	0.84	0.30	0.007	0.04	3.29	3.76	0.00	<0.001
32	1.01	0.069	0.84	0.30	0.060	0.00	3.26	3.27	0.00	<0.001
38	.96	0.073	0.81	0.28	0.070	0.00	2.96	4.90	0.00	<0.001
52	0.93	0.070	0.80	0.27	0.006	0.00	2.81	4.09	0.00	<0.001

[a]Sample number refers to day of sampling after the wellhead valve was opened initially.

Selected samples of flowback were analyzed for chemical and radioactive constituents, as shown in Table 8.2. One very interesting finding of the analyses was the high concentration of chlorides in the flowback fluid. Since chlorides were not present in the waste solution or in any constituents of the dry solids blend, their occurrence in flowback can only have originated in the host rock; Conasauga shale is of marine origin, and the appearance of salt in flowback solution therefore should not have been too surprising. The relatively high concentrations of NO_3^- indicate that some waste solution flowed back. The dominant radionuclides present in the flowback solution were ^{90}Sr and ^{137}Cs. The average concentration of ^{90}Sr was 3.65×10^4 dis min^{-1} ml^{-1}. Therefore, in the 17,000 gal of fluid flowed back, approximately 1.1 curies of ^{90}Sr was recovered, or about 0.3% of the ^{90}Sr injected. A similar calculation for ^{137}Cs shows that about 1.1 curies was recovered in the flowback fluid, representing about 0.1% of the ^{137}Cs injected.

These observations are discussed at the end of this chapter, along with those of the flowback from injection 7.

INJECTION 7

Plant Modification and Preparation

Following injection 6, considerable concern was expressed by Halliburton about the lumps that had been found in the solids blend. It was theorized that these lumps were formed during blending and aeration by water condensed from the air used in these operations. It was suggested that less water would be condensed if the air were compressed directly to 30 psi, rather than being compressed to 100 psi and subsequently reduced to 30 psi as the existing system was doing. An air blower was obtained from Halliburton to provide 450 cfm of air at a pressure of 30 psig. It was found that the electrical supply was not adequate to operate this blower in addition to the other electrical equipment that would be operating during an injection and that the electrical supply could not be increased in the time remaining before the injection. By this time, however, the source of the lumps in the dry solids had been found to be the TVA fly ash, and use of the air blower for the upcoming injection did not seem nearly as urgent. Accordingly, the blower was used to blend the solids; air for the aeration of the bulk storage bins during the injection was supplied by the portable 100-psi compressors as in previous injections.

A second Gadco dampener was bought and installed on the high-pressure discharge of the injection pump.

The procedure for proportioning the mix for injection 7 was the same as that followed in injection 6. A pneumatic transporter was loaded with fly ash at Kingston and driven to the cement plant at Knoxville. An empty transporter was parked on the cement plant scales, and fly ash was blown from the full truck to the empty one until the desired weight had been transferred. Cement was then added to the truck on the scales until the cement and fly ash in the truck were in the correct proportions. This load was then delivered to the hydraulic fracturing plant, and a second load was blended. Usually, three loads of proportioned cement and fly ash could be obtained from one load of fly ash. At the fracturing plant, the cement and fly ash were blown from the transporter to the P tank; the attapulgite, Grundite, and retarder were added by means of the "bazooka." The load in the P tank was then blended and stored in a bulk storage bin.

Blending was started on August 2, 1965. Two transporter trucks were unloaded, and the contents were blended and stored in bin 1. The third transporter truck could not be fully unloaded because there were many large lumps of caked fly ash in the bottom of the truck. The plant engineers at Kingston speculated that the lumps had gradually formed in their storage bin since it had last been cleaned. They emptied their bin, cleaned it of all accumulated fly ash, and refilled it with fresh fly ash. This necessitated the suspension of blending operations until fly ash was again available. A screen was fabricated that could be mounted on the transporter truck to strain out any fly ash lumps that might be encountered in the future.

Blending operations were resumed on August 6. Three transporter trucks were unloaded, and the contents were blended and stored in bin 2. The first of these trucks to be emptied went for the second load of fly ash, which was found to be quite wet. The blending operations were again suspended while the fly ash storage facility at Kingston was modified and the wet fly ash cleaned out of the storage bin.

Samples of the blend in bins 1 and 2 were tested in the laboratory and found to flash set with tank waste after about 1 min of mixing. The trouble was traced to the cement; apparently, enough anhydrite cement had gotten mixed with the gypsum cement to cause the flash set to occur. Just how this had occurred could not be explained by the operations people at the cement plant; in any case, no other cement was available for our use. The blend was therefore modified (by lowering the proportion of cement and increasing the proportion of DGL) so that the remaining cement could be used without risking the occurrence of a flash set.

Further experimentation showed that the blend in bins 1 and 2 could be used without risking a flash set if the chemical concentration of the waste solution was low. Several samplings of the synthetic solution in the emergency trench showed that the chemical composition was little different from that of water (Table 8.1) and that the solution could be used with the blend in bins 1 and 2.

Blending operations were resumed on August 12 and continued through August 13. There was no further difficulty with the fly ash except for an occasional delay in getting the fly ash to flow from the storage bin at Kingston. This probably resulted from the ash packing around the unloading valve. Bins 3 and 4 and both P tanks were charged with the new blend.

Injection

Because of the difficulties experienced during blending, a rather elaborate schedule of mix proportioning for injection 7 was adopted (Table 8.3).

Table 8.3. Mix Proportioning Schedule for Injection 7

Container	Solution	Mix Ratio (lb/gal)	Corresponding Density (lb/gal)	Volume (gal)
Bin 3	Water	6.25	11.15	First 5000
Bin 3	Waste tank	7.00	11.75	
Bin 4	Waste tank	7.00	11.75	
P tank	Waste tank	7.00	11.75	
P tank	Waste trench	8.00	11.75	
Bin 1	Waste trench	8.00	12.00	
Bin 2	Waste trench	8.00	12.00	
Bin 2	Water	9.00	12.20	Last 5000

The previous fracture of injection 6 was broken down with 104 gal of water at 1600 psi.

The injection was started at 9:00 AM, August 16, 1965. As planned, a water-solids mix was injected for the first 20 min to determine that the mass flowmeter was working well before switching to waste solution. The mass flowmeter appeared to be working quite well, and at 9:22 the injection of waste solution was started.

The lb/min readout from the mass flowmeter was integrated every 5 min to give a running total of the amount of solids that had been consumed. Fairly early it became apparent that the mass flowmeter readings were too high; at 10:28, when bin 3 ran empty and the integrated lb/min curve indicated that 153,000 lb of solids had been consumed (128,000 lb in bin 3), it was obvious that the readings were high. The total solids in bin 3 divided by the total gallons pumped to that time indicated that the mix ratio to that time had been about 6 lb/gal instead of the nearly 7 lb/gal that was desired. The solids rate was accordingly increased. During the time that bin 4 was being emptied, the readings from the mass flowmeter were integrated as before, but more faith was being placed in the Densometer readings because the mass flowmeter readings were obviously badly in error. At 12:10 PM, bin 4 ran empty. The integrated mass meter readings at this time indicated that 199,000 lb of solids had been taken from bin 4 (152,000 lb were in there). The error at this point was greater than the error when bin 3 had run empty; from this point on, faith in the mass flowmeter was nonexistent.

Starting at about 11:00 AM, the lb/gal readout of the mass flowmeter had gone off scale. The system components had been sized to read up to 8 lb/gal at a time when the probable mix ratio was about 5 lb/gal. The heavier than expected mix ratios and the inaccuracy of the mass flowmeter had combined to force the instrument beyond its design range. The lb/gal readout part of the instrument was disconnected, and readings were thereafter taken of the lb/min flow only.

Starting at 12:10 PM, solids were taken from bin 3, which had been refilled from the P tanks while bin 4 was being emptied. Densometer and mud balance readings had indicated that the slurry being injected did not have enough solids; the flow of solids was accordingly increased. Shortly thereafter the Densometers began plugging, and it was noted that the slurry in the surge tank was stiff, was difficult to pump, and tended to set. At 12:50 the injection was halted, the well was overflushed with water, and the surge tank and various slurry lines were washed. While the injection was shut down, it was noted that the mass flowmeter was indicating a flow of 2700 lb/min. The injection was restarted at 1:15.

At 1:35 bin 3 was empty, and flow was switched to bin 1 – the bin that was thought to contain many lumps of caked fly ash. To everyone's surprise, the smoothest operation of the injection prevailed while this bin was being emptied.

At 2:48 flow was switched to bin 2, and at 3:30 it was estimated that the solids left in bin 2 would suffice for only 15 min more operation; the solution flow was therefore switched so that water was being mixed and injected instead of the solution from the emergency waste trench. The solids lasted longer than expected; the storage bins did not run empty until 4:24 PM.

The injection well was overflushed with water and valved shut. The system was washed and carefully checked to be sure that all lines were open. The following day the bins and air slides were checked, and the small remaining amount of solids mix was cleaned out and discarded. The estimated remaining solids weight was 3000 lb.

Figure 8.7 shows the liquid volume pumped during the injection as measured by waste storage tank volumes and the Halliburton flow totalizer. The totalizer was apparently reading about 15% high.

Table 8.4 is a log of the injection. The volumes are from waste storage tank volumes.

Figure 8.8 is a plot of the mass flowmeter readings during the injection, an equivalent mass flow rate calculated from Densometer readings, and the difference between these two values. A comparison of these curves shows a gradually increasing difference for the first 90 min and a nearly constant difference thereafter, except for a 30-min period when the mass flowmeter was

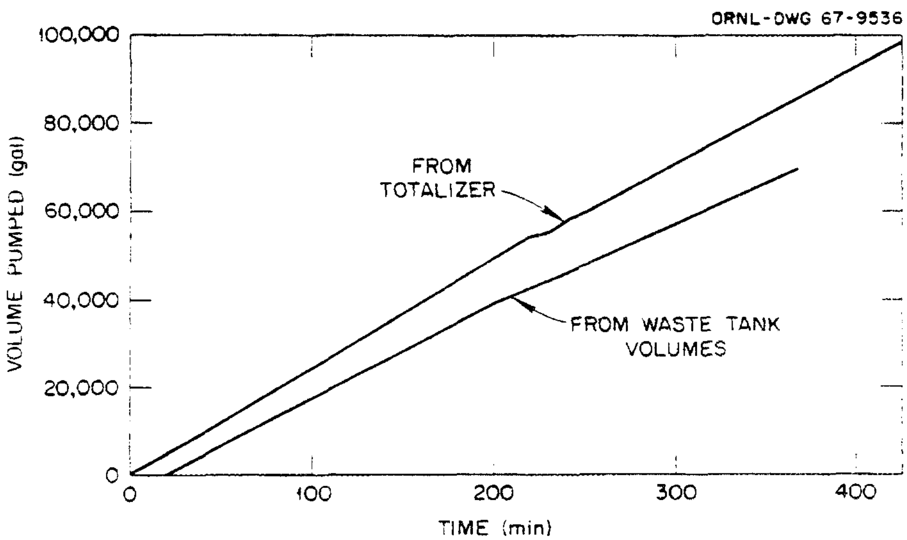

Fig. 8.7. Liquid Volume Pumped in Injection 7 as Measured from Waste Storage Tank Volumes and from Halliburton's Flow Totalizer.

Table 8.4. Log of Injection 7

Time From	Time To	Bin No.	Solution	Volume Pumped in Interval (gal)	Flow Rate (gpm)	Mix Ratio Desired (lb/gal)
900	920	3	Water	4,440	222	6.25
920	1028	3	Waste	15,110	222	7.00
1028	1210	4	Waste	22,660	222	7.00
1210	1218	P	Waste	1,800	222	7.00
1218	1250	P	Trench	4,000	158	8.00
1315	1335	P	Trench	4,000	195	8.00
1335	1444	1	Trench	14,000	185	8.00
1448	1530	2	Trench	8,000	195	8.00
1530	1624	2	Water	10,500	185	9.00

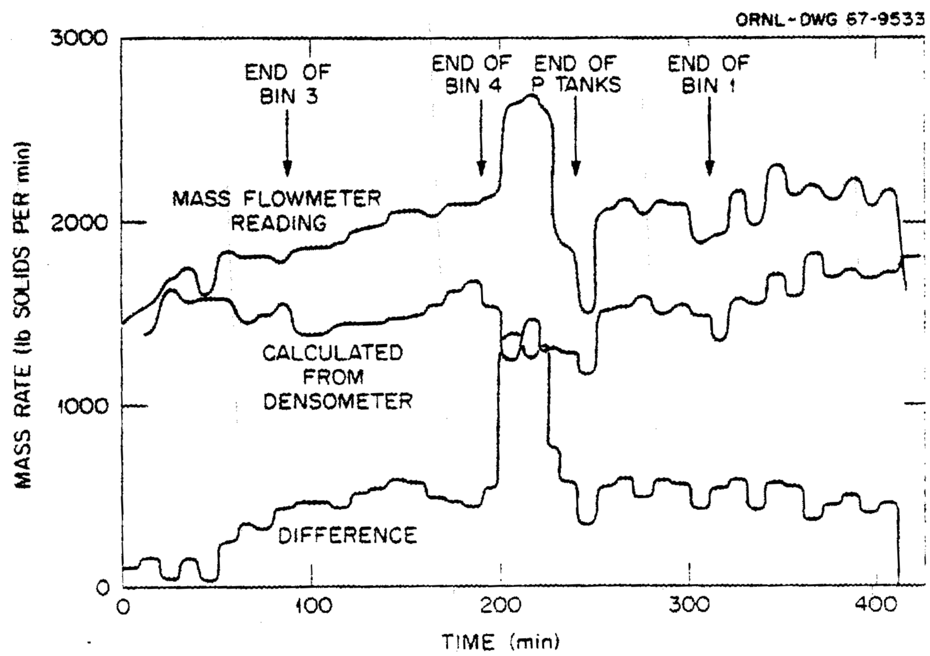

Fig. 8.8. Mass Flowmeter Readings During Injection 7 as Compared with Calculated Mass Flow Rate from Densometer Readings.

indicating very high flows and the Densometer was indicating lower than average flows. This particular period corresponds to that part of the injection just prior to the shutdown, when the slurry was particularly viscous; the Densometer was giving erratic readings and flow was very difficult to maintain. Since these conditions would be expected if too high a proportion of solids were being used, it seems most probable that the mass flowmeter was more nearly correct in this case and that the Densometer was giving false readings because of plugging, excessive air entrapment, or some other reason. Integration of the mass flowmeter curve yields a figure of 835,000 for the total weight of solids consumed; integration of the Densometer curve yields a figure of 635,000 lb (with no correction for the 30 min when consumption was probably much higher than indicated). Since only 588,000 lb of solids were actually used, the accuracy of both curves is obviously poor. It was noted during the injection that solids were building up on the mass flowmeter and giving high readings. This observation is generally consistent with the shape of the curve showing the difference between mass flowmeter and Densometer readings – a gradually increasing difference for about 90 min and a fairly constant difference thereafter. The mass flowmeter curve is therefore corrected by subtracting a fixed quantity from each reading above 90 min and a quantity proportional to time from each reading up to 90 min; the amount subtracted is chosen so that an integration of the corrected curve will show the consumption of 588,000 lb of solids. The corrected curve is shown in Fig. 8.9.

Figure 8.10 is derived from flow rates and the corrected lb/min curve and shows the desired and the actual solids to liquid ratios achieved during the injection. This curve shows that, except for a short period, the actual mix ratio was substantially below the desired mix ratio.

Flowback from Injection 7

Injection 7 was successfully completed on August 16, 1965. The injection was made into the same slot (872 ft) that was used in the concluding part of injection 6. The wellhead valve was opened initially on August 31; pressure at the wellhead prior to the start of flowback was

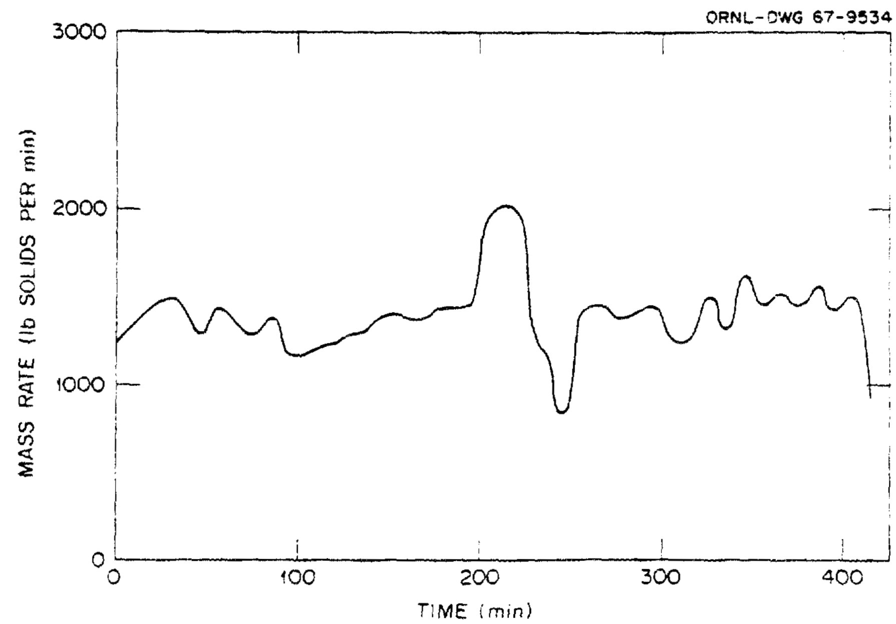

Fig. 8.9. Solids Flow Rate from Corrected Mass Flowmeter Curve, Injection 7.

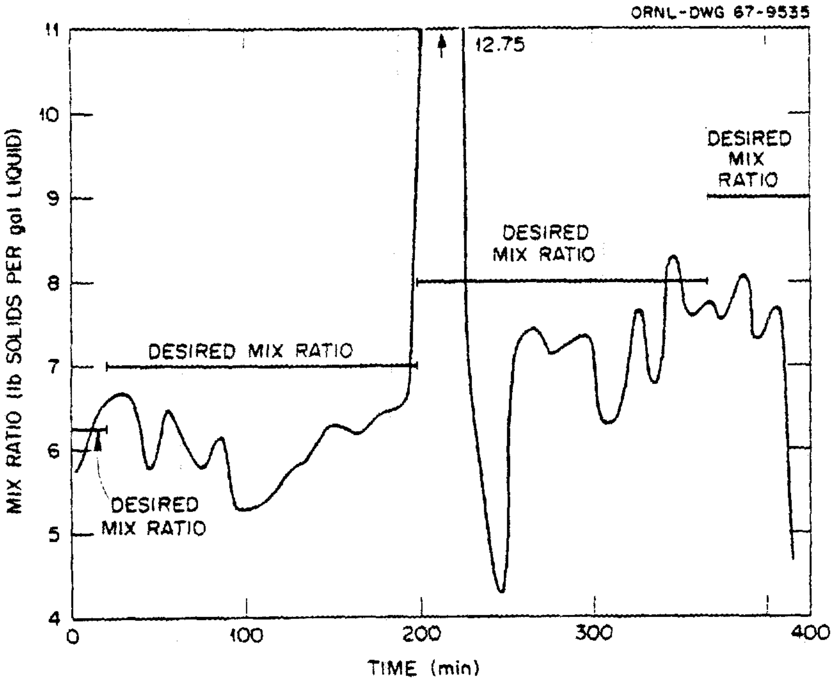

Fig. 8.10. Desired Mix Ratio and Actual Mix Ratio for Injection 7.

335 psi. During the next three days, the rate of the flowback was approximately 10 gpm; then the rate decreased rapidly and by the 5th day was 5 gpm and by the 14th day, 0.5 gpm. The well was shut in from the 23d to the 48th day after initial opening and then reopened. Flowback measurements then continued for an uninterrupted period of 77 days, constituting a total elapsed time of flowback of 100 days. Measurements of flow rate, volume, conductivity, pH, chemical concentration, and radionuclide concentration were made as before.

The rate of flowback with time and the cumulative volume are plotted in Fig. 8.11. The total volume collected was 19,800 gal; extrapolation of the flow rate indicates that 20,600 gal could have been collected – an additional 800 gal.

The conductivity and pH measurements of samples taken during flowback are shown in Fig. 8.12. The conductivity of the fluid increased with time; but unlike flowback from injection 6, the conductivity did not decrease in the later samples. As in injection 6, the pH of the samples decreased with time; the final samples showed pH's of approximately 11.

The chemical and radiochemical analyses of selected samples are shown in Table 8.5. As was observed in the flowback from injection 6, the chloride content was high. The last two samples included in Table 8.5 are of liquids from laboratory tests of phase separation with slurries obtained from the fracturing plant during injection 7. Note the absence of chlorides in these solutions, thus verifying the earlier conclusion that the chlorides must have originated in the shale formation. Note again the comparatively high nitrate concentrations, indicating that some of the flowback must have come from the injected waste slurry.

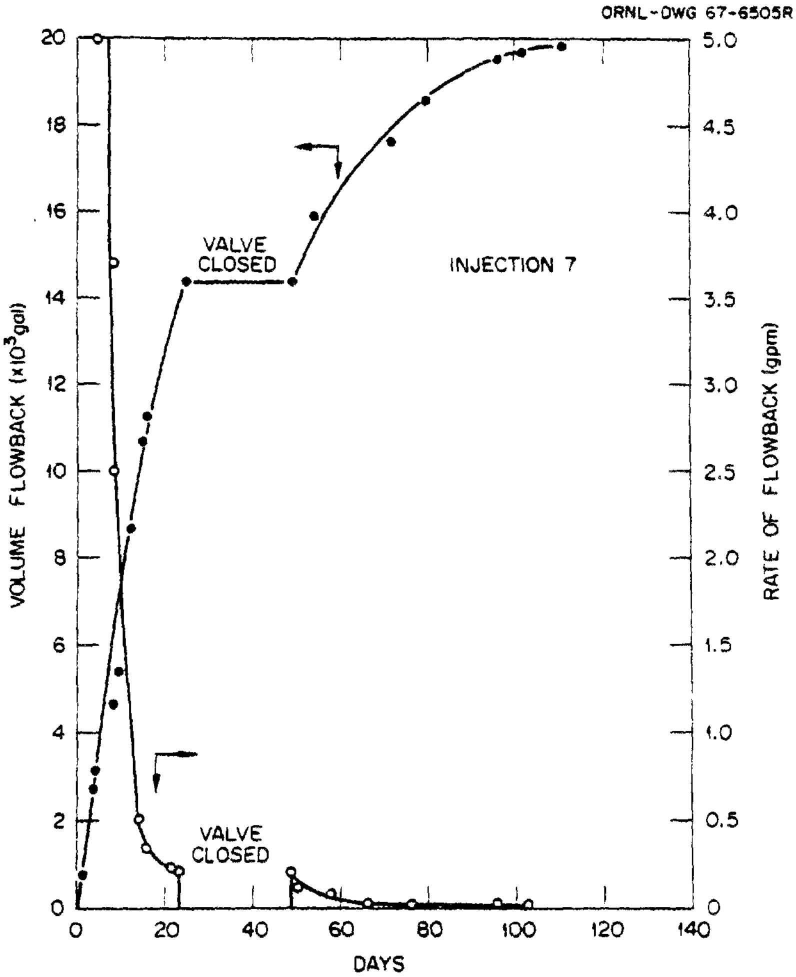

Fig. 8.11. Flow Rate and Cumulative Volume of Flowback with Time.

The total amount of ^{137}Cs in the flowback from injection 7 was 0.8 curie, or less than 0.1% of the total ^{137}Cs injected. Based on the average concentration of ^{90}Sr in samples taken to that stage, approximately 0.2 curie of ^{90}Sr was returned by the time 11,000 gal of flowback had accumulated. However, the ^{90}Sr concentrations gradually increased with time, so the total amount returned was probably more than 0.2 curie. If we extrapolate the apparent rate of increase over the last 10,000 gal of flowback and calculate the total amount of ^{90}Sr returned, it appears that an additional 0.3 curie may have flowed back. Even if a total of 0.5 curie of ^{90}Sr flowed back, it represents only about 0.1% of that injected.

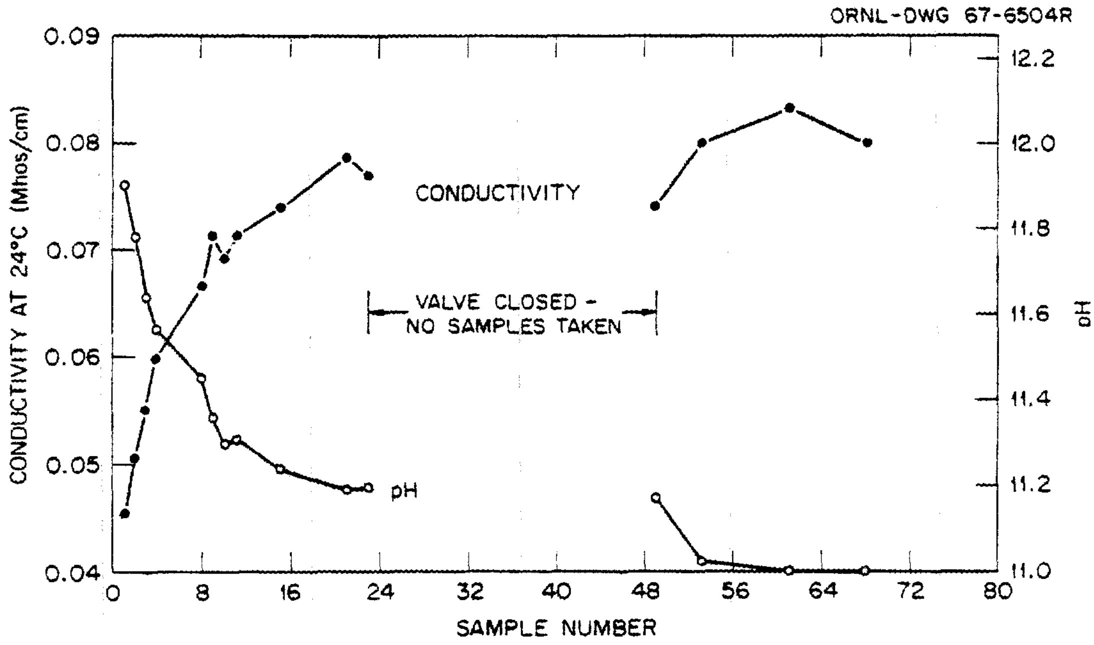

Fig. 8.12. Conductivity and pH Measurements of Flowback, Injection 7.

Table 8.5. Chemical and Radiochemical Composition of Flowback from Injection 7

Sample No.[a]	Concentration (*M*)						Nuclide Concentration (dis min^{-1} ml^{-1})			
	Na^+	Ca^{2+}	Cl^-	NO_3^-	SO_4^{2-}	CO_3^{2-}	^{137}Cs	^{90}Sr	^{106}Ru	^{60}Co
							$\times 10^4$	$\times 10^4$	$\times 10^4$	$\times 10^4$
1	0.46	0.015	0.28	0.17	0.007	0.004	2.27	0.51	0.024	0.01
2	0.53	0.024	0.38	0.18	0.008	0.004	2.22	0.54	0.027	0.018
3	0.63	0.038	0.48	0.18	0.010	0.003	2.32	0.52	0.033	0.006
4	0.66	0.042	0.53	0.19	0.010	0.002	2.38	0.66	0.018	0.000
8	0.74	0.048	0.61	0.19	0.006	0.003	2.26	0.88	0.032	0.000
10	0.080	0.064	0.69	0.19	0.008	0.002	2.48	0.93	0.026	0.000
15	0.89	0.083	0.83	0.20	0.007	0.001	2.71	1.19	0.025	0.000
Tank waste[b]	0.94	0.000	0.012	0.64	0.096	0.06	1.35	0.035	2.28	2.09
Trench waste[b]	0.19	0.000	0.008	0.07	0.000	0.03	2.37	0.050	0.02	0.02

[a]Sample number refers to day of sampling after the wellhead valve was opened initially.

[b]These are samples from phase separation tests conducted in the laboratory.

PHASE SEPARATION STUDIES

Laboratory Tests

During late stages of the mix development program, when emphasis was being put on low-solids-content mixes, we began to suspect that the shear imparted to slurries prepared by API techniques in the laboratory did not correspond to the shear imparted in the fracturing plant. If this was indeed the case, then our laboratory tests of phase separation were meaningless, or largely so.

In preparing test slurries in the laboratory, two conditions in the fracturing plant supposedly were being simulated. First, conditions in the jet mixer were being simulated by adding dry solids to the waste solution over a period of 15 sec while the Waring Blendor was rotating at "slow" speed. Second, to simulate conditions of flow through the high-pressure piping in the plant and down the injection well, the initial mixing was followed by rotating the Waring Blendor for 35 sec at "high" speed. The API procedure specifies "4000 rpm or greater at no load on 'slow' speed and 10,000 rpm or greater at no load on 'high' speed." Our Blendor was found to rotate at 5200 rpm on slow speed and at 10,560 rpm on high speed. We were concerned about this because large differences in the degree of phase separation in laboratory slurries were being observed, depending on the speed at which the Blendor was rotated.

Three samples of slurry were taken from the fracturing plant during injection 6 and brought to the laboratory. The samples were stirred for 35 sec at either 5200 or 10,560 rpm. The first sample, whose bulk density equaled the specified value of 11.7 lb/gal, was stirred at 10,560 rpm and showed no phase separation. The second sample was stirred at 5200 rpm and showed a phase separation of 29%. However, its bulk density indicated that the slurry was low in solids by approximately 10%. The third sample, low in solids by about 5%, was stirred at 5200 rpm and showed a phase separation of 22%. Slurries prepared in the Blendor which were low in solids by 10 and 5% showed phase separations of 7 and 5%, respectively, when stirred at 5200 rpm. The higher phase separations in the plant slurry were therefore ascribed to a shear that was even less than that imparted by the "slow" speed of the Waring Blendor.

The volume of flowback from injection 6 represented a 26% phase separation, based on the 64,000 gal injected. Laboratory tests of slurries prepared with samples of the dry solids blend from the plant's storage bins showed a phase separation of approximately 25% when the slurries were stirred for 50 sec at 4000 rpm. This agreement is remarkably good but probably fortuitous.

The mix formulation for injection 7 was based on laboratory tests of phase separation with slurries prepared in a different manner. Here we added the solids to the solution in the Blendor for 15 sec while stirring at 4000 rpm. The slurries were then stirred for an additional 35 sec at the same speed. The mix specifications (solids/liquid ratio and bulk density) were varied according to the different compositions of waste solutions in the storage tanks and in the emergency trench, and according to the different dry solids blends in bins 1, 2, 3, and 4. The solids/liquid ratio varied from 7 to 9 lb/gal, and the corresponding bulk densities ranged from 11.75 to 12.00 lb/gal.

The volume of flowback from injection 7 (20,500 gal) represented a 24% phase separation, based on the 84,510 gal injected. However, due to the erratic performances of both the flowmeter and the Densometer during this injection, the actual solids to liquid ratios achieved, except for one brief interval, were substantially below those desired, 10 to 15% lower. Hence the actual phase separations were probably more nearly 9 and 14% respectively.

Interpretation of Flowback Results

The conductivity of a solution is a function of the dissolved ion concentration of the solution. The flowback from both injections 6 and 7 contained considerable salts. Inspection of the data suggested that the conductivity of the flowback fluid might be related to the sodium concentration since sodium hydroxide and sodium nitrate constitute the bulk of the dissolved salts. The relationship of the conductivity to the sodium concentration is shown in Fig. 8.13. The slightly higher nitrate concentration in the flowback from injection 6 is explained by the fact that the waste solution injected was approximately 3×. The relatively high concentration of chlorides in the flowback from injection 7 suggests that the injected grout did not occupy the same fracture as the grout in injection 6; if it had, one would expect the chloride content in both flowback fluids to be approximately the same. The gradual increase in the chloride concentration of the flowback from injection 7 may be an indication that the injected grout followed the fracture of injection 6 initially and then later created a new fracture.

The ^{90}Sr content in samples of flowback from both injections appeared to increase with time. This indication was much stronger in the flowback from injection 7 than in that from injection 6.

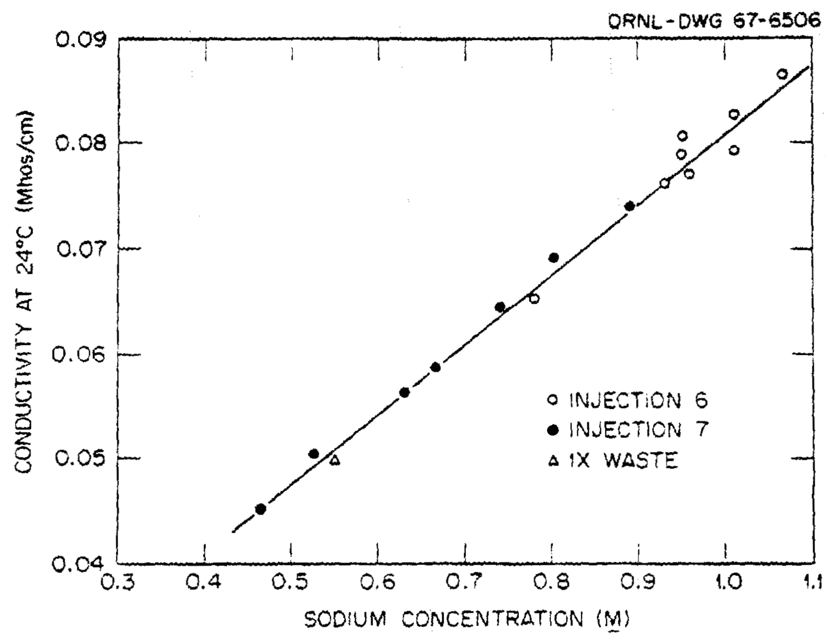

Fig. 8.13. Conductivity of Flowback from Injections 6 and 7 as a Function of Sodium Concentration.

A possible reason for this may be found in the lower pH of samples taken in the late stages of flowback. With a decrease in pH, the solid hydroxides of calcium and strontium would dissolve and therefore would more likely be released with the flowback fluid. Recall that the addition of pozzolan (fly ash) was to decrease the "free" calcium hydroxide content; this reaction occurs rather slowly, and there may not have been enough time for the reaction to take place during the flowback intervals involved (60 to 80 days).

CONCLUSIONS

During injection 6, two separate incidents caused contamination of the cells. Both in the mixer cell and in the wellhead cell, decontamination was accomplished and repairs were made without exceeding the weekly permissible radiation dose to operating personnel. The highest radiation exposure to cleanup personnel involved in cell decontamination was 30 mr.

It was also necessary to make repairs to the pump during this injection. The general background with the heads off the pump was 20 mr/hr; the radiation inside the pump was 1 r/hr. One mechanic received an exposure of 20 mr, and the other received 10 mr. These levels show that direct maintenance on the injection pump is feasible with wastes whose activity is approximately 0.1 curie/gal.

Injection 6 demonstrated the ease with which an injection can be halted, repairs made, and the injection resumed. This was done twice during the injection; in both instances the injection was resumed without difficulty.

Several conclusions concerning mix formulation may be drawn from the results of injections 6 and 7. First, the dry solids content of the slurry should be approximately 10% higher than the minimum necessary to prevent phase separation. Using a 10% higher solids to liquid ratio (thickening time to be adjusted with DGL) allows for a possible 10% decrease in mix proportioning with either the Densometer or the mass flowmeter, or both. Second, pozzolan is a good additive for the mix if it is obtainable in a perfectly dry state. During injection 7, the flow of solids from the bins to the jet mixer was extremely smooth when the pozzolan was dry. Third, even with phase separation as high as 25%, over 99% of the injected radioactivity will remain in the set grout. Finally, the high concentration of chlorides in the flowback suggests that their effects on mix formulations should be investigated.

9. Operational Injections ILW-1 and -2 [1]

When injection 7, the last experimental injection, was made in August 1965, the Laboratory's new waste evaporator plant was under construction but not yet completed; so the fracturing plant was put in standby.

Arrangements were completed by May 1966 for the Operations Division to assume responsibility for the fracturing plant. Thereafter, they were to use the plant for the routine injection or disposal of the Laboratory's intermediate-level waste. We in the Health Physics Division were to assist in performing these injections, being concerned primarily with mix formulations, with the underground distribution of injected grout sheets, and with the effects of repeated injections on the cover rock. A very important question remained concerning the application of hydraulic fracturing for waste disposal: What is the life expectancy of the well, or, in another way, what is the capacity of the disposal formation? The answer to this question could be obtained as well by observing the effects of real waste injections as by observing continued injections of synthetic wastes.

To understand the implications of the decision to use the fracturing plant for actual disposal, it is necessary to review the earlier history of the management of these wastes. During the last years of World War II, the Laboratory first started reprocessing fuel elements from the Graphite Reactor, primarily to remove plutonium, and this operation produced what we class as an intermediate-level waste. This waste was neutralized with sodium hydroxide and stored in a series of concrete tanks lined with mild steel. Most of these tanks were built in 1943. They have a combined capacity of about a million gallons and had an estimated life, when built, of about 20 years. The neutralization produced precipitates, largely iron and aluminum oxides and hydroxides, which contained the greater part of the fission product strontium as carbonate and some of the other fission products in one form or another. The supernatant liquid, however, contained the bulk of the fission products cesium and ruthenium. Providing tank capacity to store these wastes was expensive, and about 1950 an evaporator was built to reduce their volume. No great care was taken in the design of this evaporator, however, as at that time few people believed the Laboratory would continue to operate the waste-producing facilities for more than a very few years at most. Consequently, the evaporator used large amounts of steam and was very expensive to operate.

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[1] This identification of injections differs from that previously used to identify the *experimental injections*. Recognizing the importance of recording *operational injections* distinctly, the Operations Division chose to identify each injection of Intermediate Level Waste as ILW-1, ILW-2, etc.

In 1952 the Laboratory started to dispose of the neutralized intermediate-level liquid waste into earth seepage pits, and in 1954 the evaporator was no longer required and was dismantled. The wastes were still neutralized, however, and most, but not all, of the sludges formed remained in the tanks.

In 1958 it was generally agreed that disposal of the liquid supernatant and some of the entrained sludge into surface seepage pits left something to be desired. In 1959 and 1960, certain very real problems developed with the seepage pits; later, in 1961, seepage pit 6 sprang a leak the first time it was filled and had to be taken out of service. Seepage pit 7, built in 1962, was usable but far from satisfactory, and it was obvious that some other, better system would have to be found to handle the supernatant from the neutralized intermediate-level waste.

About 1963, therefore, a decision was reached to build a new and more efficient evaporator; this went into service in the summer of 1966. The original plans for the new evaporator called for tanks in which to store the concentrated waste, because in 1963 the feasibility of safe disposal by hydraulic fracturing had not yet been proven. Following injection 7, however, serious thought was given to converting the experimental plant into an operating facility, and in 1966 a decision was reached to go ahead on this basis. Consequently, a thorough review of the plant was made by several Divisions at the Laboratory (including the Operations Division, which was now responsible for the plant) and by the Halliburton Company. Many seemingly minor modifications and improvements were made, but in total they greatly improved all phases of the plant operation.

UPGRADING THE FRACTURING PLANT

Most important was the need to increase the waste storage capacity at the plant site, which was only about 40,000 gal. To this end, two surplus tanks, with a combined capacity of 47,000 gal, were located at the Y-12 Plant. These tanks were refitted for waste storage by ORNL shop forces and turned over to the local construction contractor for installation and connection to the existing system. Figure 9.1 is a photograph of the completed tank farm at the fracturing plant. The locations of the five tanks can be gaged by the locations of the nozzles or "manholes," four of which are clearly visible; the fifth is behind the flowmeter rack in the middle of the picture. To the right of the photo are the TBP metering pump and storage drums, the valve pit, and the waste pumphouse; also visible in the background is a new substation designed to increase the amount of electric power at the site.

Another significant improvement was realized with the purchase and installation of the 820-ft^3 weigh tank shown in Fig. 9.2. This simplified the dry solids blending system and eliminated the extra manpower required to weigh the cement and fly ash at the cement plant. This modification, together with Halliburton's improvement of both the Densometer and the mass flowmeter, gave much better control over the proportioning of solids to liquids during the two operational injections.

Other major improvements included the upgrading of electrical power service (mentioned above), the installation of a separate off-gas system for the surge tank, a new process water line,

Fig. 9.1. View of the Waste Storage Facilities.

and replacement of a plastic section in the waste transfer line with stainless steel. The existing 2400-v power service was inadequate, causing the pump motors to overheat during long periods of operation. A more efficient off-gas system for the surge tank was needed to reduce the possibility of airborne releases to plant environs from the elevated concentrations of activity expected in evaporator concentrate. Plant modifications were completed with the installation of a shelter for the main injection pump and painting of the solids storage bins and much of the rest of the plant.

It may be appropriate here to record other improvements to be added later as funds become available. They include:

1. an equipment storage building with a permanent change house,
2. one 3500-ft^3 bulk clay storage bin to eliminate handling bagged clay materials,
3. radiation detectors in each cell to detect leaks as quickly as possible,
4. a dual strainer in the waste line to the suction side of the waste pumps,
5. check valves in the process water lines to eliminate or minimize the possibility of waste solutions entering the process water system.

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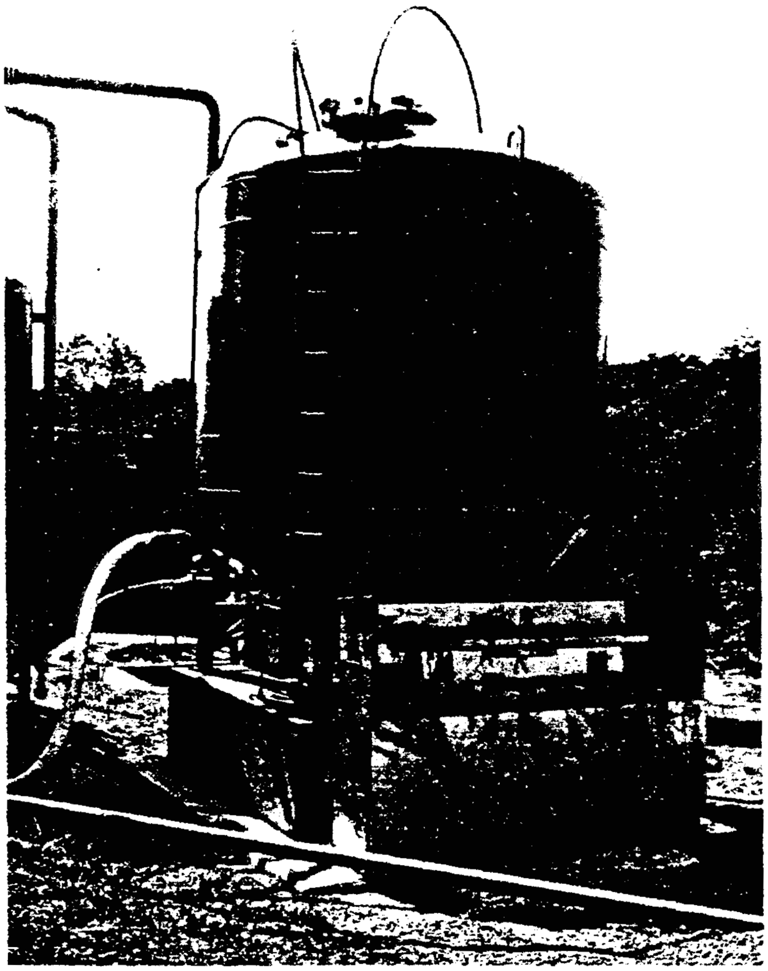

Fig. 9.2. View of the Weigh Tank.

The first ILW injection was finally scheduled for December 12, 1966, and Halliburton was asked to provide a maintenance crew several days in advance. The plant had not been operated for 15 months, strongly suggesting the possibility of equipment failure and the need for a detailed plant checkout.

WASTE COMPOSITION AND MIX FORMULATION

Waste Composition

As is customary before each injection, waste samples were taken from the evaporator-concentrate storage tank, located in the south tank farm of the main Laboratory area, and were analyzed for chemical and radioactive constituents. These samples were also used to develop the mix formulations in the laboratory beforehand, so that the bulk solids could be blended according to the fixed proportions of dry solids and so that the slurry properties could be determined. The chemical and radionuclide contents of the wastes injected in ILW-1 and ILW-2 are shown in Tables 9.1 and 9.2.

Table 9.1. Chemical and Radionuclide Content of Waste Disposed Of in Injection ILW-1

	ILW-1A	ILW-1B
Chemical concentration (*M*)		
Sodium hydroxide	0.05	0.02
Sodium nitrate	0.75	0.51
Ammonium sulfate	0.15	0.09
Aluminum sulfate	0.04	0.04
Sodium chloride	0.05	0.04
Sodium carbonate	0.04	0.01
Radionuclide content (curies)		
^{90}Sr	41	38
^{137}Cs	11,500	7600
^{106}Ru	1	8
^{60}Co	16	3
^{144}Ce	20	13

Table 9.2. Chemical and Radionuclide Content of Waste Disposed Of in Injection ILW-2[a]

	ILW-2A	ILW-2B
Chemical concentration (*M*)		
Sodium hydroxide	0.06	ND
Sodium nitrate	1.00	ND
Ammonium sulfate	ND	ND
Aluminum sulfate	ND	ND
Sodium chloride	ND	ND
Sodium carbonate	ND	ND
Radionuclide content (curies)		
^{90}Sr	564	474
^{137}Cs	31,329	26,350
^{106}Ru	99	83
^{60}Co	236	199
^{144}Ce	ND	ND

[a]ND = not determined.

Mix for Injection ILW-1

This slurry had the following composition and properties:

Composition	Evaporator concentrate waste 400 ppm TBP 2.22 lb portland cement (type II) per gallon of waste 2.22 lb Kingston fly ash per gallon of waste 1.00 lb Attapulgus 150 per gallon of waste 0.57 lb Grundite per gallon of waste 0.003 lb CFR-1 per gallon of waste
Density	11.5 lb per gallon of waste 11.6 lb per gallon of water
Volume	1.35 gal per gallon of waste
Viscosity	8 poises
Water separation	0%
Fluid loss	225 ml in 30 min (100 psi test)
Pumping time	7 hr at 89°F
Compressive strength	Not determined
Density of site waste	1.0746 g/cm^3 at 23°C
Density of laboratory waste	1.0787 g/cm^3 at 25°C
Material cost	5.9 ¢/gal

Mix for Injection ILW-2

The mix for this injection was unique in that the retarder (delta gluconolactone) (CFR-1) was omitted for the first time as a test of its effect on the phase separation problem currently under study. This slurry had the following composition and properties:

Composition	Evaporator concentrate waste 400 ppm TBP 2.30 lb portland cement (type II) per gallon of waste 2.30 lb Kingston fly ash per gallon of waste 1.05 lb Attapulgus 150 per gallon of waste 0.59 lb Grundite per gallon of waste No CFR-1
Density	11.7 lb per gallon of waste
Volume	1.34 gal per gallon of waste
Viscosity	10.0 poises
Water separation	3% before setting; 1.5% after setting
Fluid loss	Not determined
Pumping time	$>7\frac{1}{2}$ hr at 65°F
Compressive strength	Not determined
Material cost	6.1 ¢/gal

INJECTIONS ILW-1A AND -1B

Preliminary Preparations

Approximately four days were required to weigh and blend the dry solids. The four storage bins will hold about 800,000 lb of blended dry solids, enough for about 120,000 gal of liquid waste. About 590,000 lb of solids, containing 160,000 lb of portland cement (type II), were prepared for this injection.

As the dry solids were being blended, ILW waste was transferred from the south tank farm to the fracturing plant site via the waste transfer line. Prior to the transfer, the line was tested with water pressure to check for leaks; this procedure is always followed prior to each injection.

Reslotting the casing was unnecessary, since it was planned to inject into the same slot at 872 ft used for injections 6B and 7.

Injection

Since the two additional waste storage tanks were not yet ready for service, the injection was performed in two parts on consecutive days, December 12 and 13, 1966. To inject approximately 80,000 gal of waste, the procedure was as follows: As soon as the first of the three available tanks at the plant site was empty, more waste was pumped to it from the south tank farm so that all three tanks would be refilled by the next day.

Beginning at 9:00 AM, the first injection, ILW-1A, was started by pumping about 200 gal of water to open the slot. From 9:04 AM to 12:15 PM, 37,440 gal of waste, or 53,400 gal of slurry, was injected, as shown in Fig. 9.3. Control of solids/liquid proportioning was by the mass

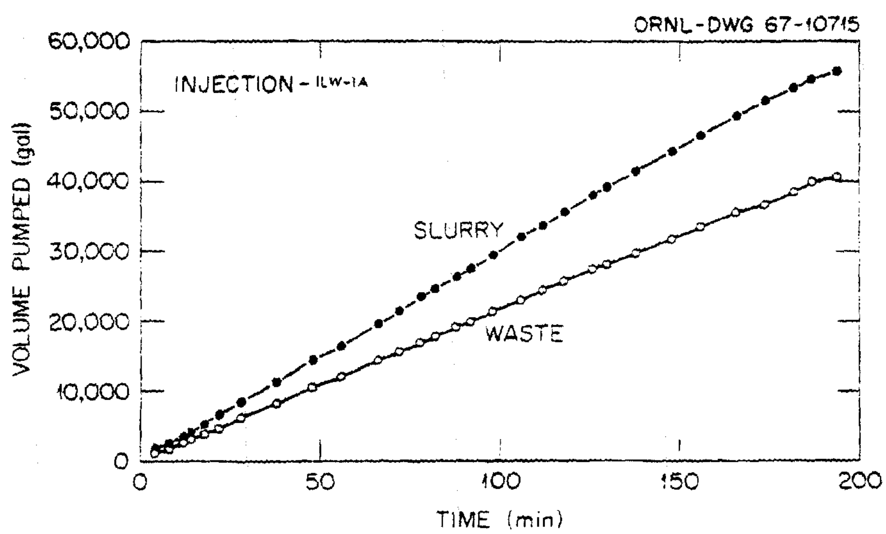

Fig. 9.3. Waste and Slurry Volumes Pumped During Injection ILW-1A.

flowmeter and was fairly steady, as shown in Fig. 9.4. Deviations in slurry density occurred while changing the solids from bin to bin. The injection pressure and injection rate are shown in Fig. 9.5. It was estimated that about 250,000 lb of solids had been used, leaving approximately 184,000 lb for the next day. At the end of the run, about 600 gal of fresh water was cir-

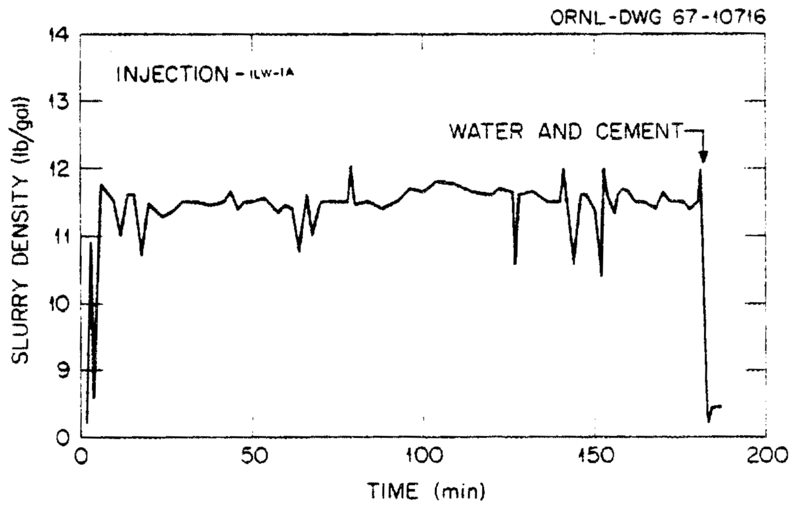

Fig. 9.4. Solids/Liquid Proportioning During Injection ILW-1A.

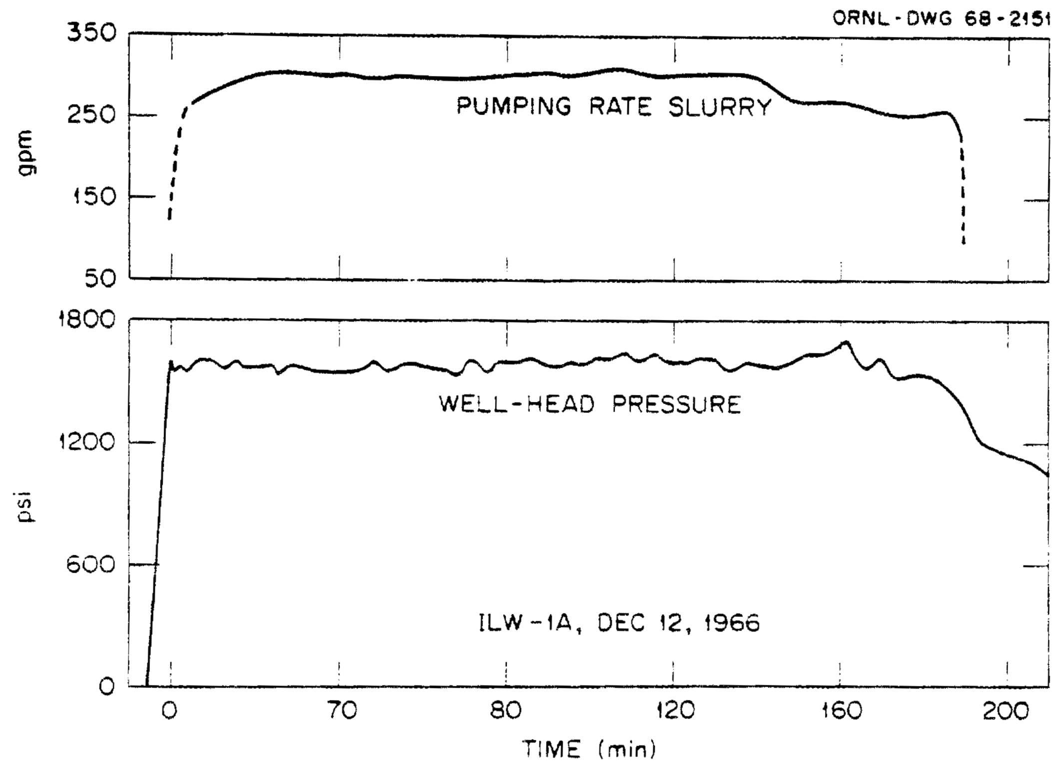

Fig. 9.5. Injection Pressure and Injection Rate During Injection ILW-1A.

culated through the plant to clean all fluid lines and the Densometers and was pumped into the well to overdisplace the radioactive grout. Then the well was closed in.

Injection ILW-1B, comprising about 26,000 gal of waste or 35,000 gal of slurry (Fig. 9.6), was completed on December 13. The plant operated smoothly, and the Densometer and mass flowmeter appeared to do a good job of proportioning the preblended solids to the liquid waste (Fig. 9.7). Injection pressure and rate were about the same as the previous day (Fig. 9.8).

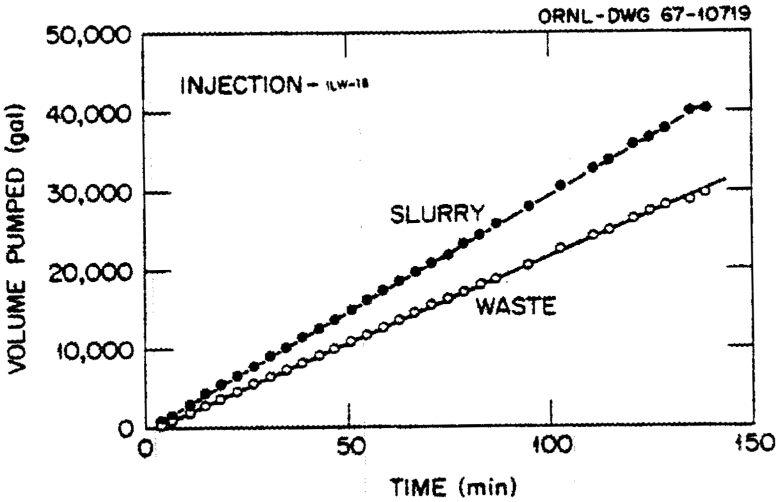

Fig. 9.6. Waste and Slurry Volumes Pumped During Injection ILW-1B.

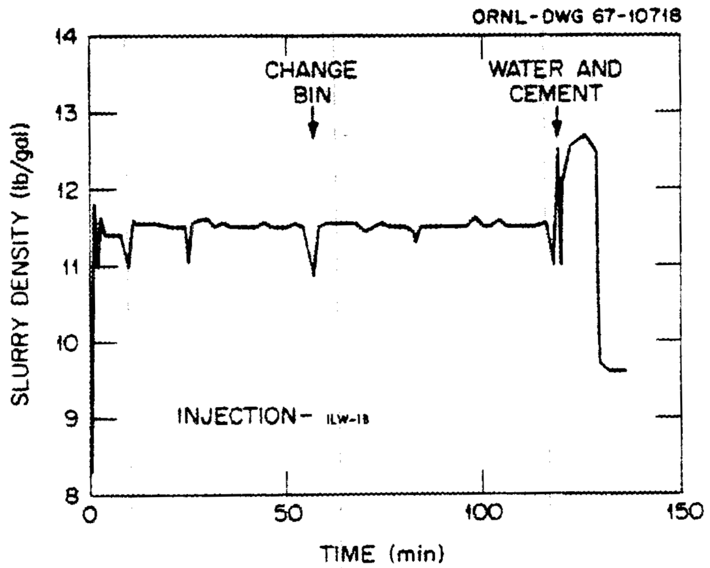

Fig. 9.7. Solids/Liquid Proportioning During Injection ILW-1B.

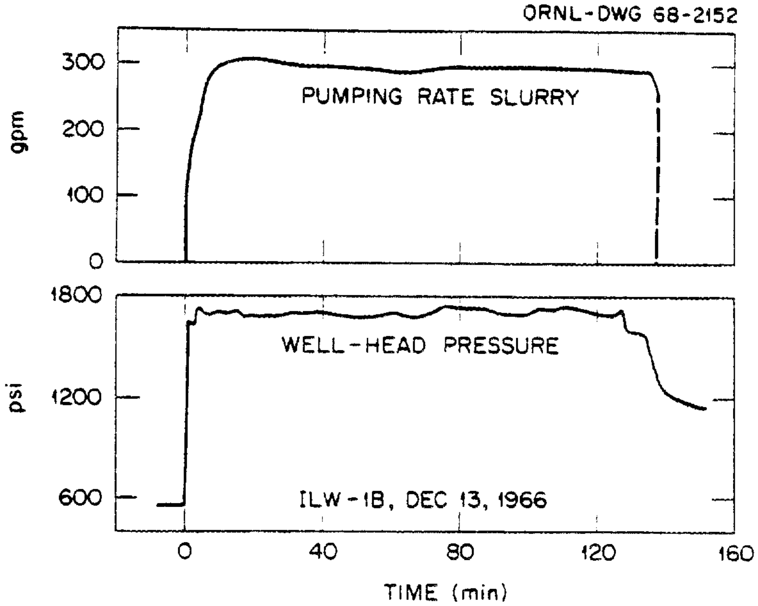

Fig. 9.8. Injection Pressure and Injection Rate During Injection ILW-1B.

In assessing the overall performance of the plant during these two injections, it is important to record the fact that we were able to obtain dry fly ash for the first time.

INJECTION ILW-2A

Preliminary Preparations

The slot at 872 ft, which contained injections 6B, 7, ILW-1A, and ILW-1B, was sealed with a cement plug on April 18, 1967. The plug was set with the HT-400 waste injection pump, since the Halliburton standby pump truck usually used for this operation had been delayed by a broken drive shaft. Three percent calcium chloride was added to the cement, and the plug was tested the next day and found to be tight. A new slot was cut at a depth of 862 ft, and the fracture was initiated with 560 gal of water at a pressure of 2500 psi.

Solids were blended, and 585,310 lb were stored in the bins and 147,230 lb in the three P tanks. The solids in the P tanks were transferred to the bins as soon as space was available.

Injection

The standby truck arrived at 1 PM, April 20, and was immediately connected to the fresh water supply at the HT-400 pump cell. The well was broken down at 1:45. The pump operator noted a breakdown pressure of 3300 psi, as compared with only 2500 psi required to initiate the fracture on the previous day. This higher pressure is believed to have been a brief transient, because the pressure as measured somewhat more reliably on the annulus of the injection well reached only 2450 psi. The injection was completed in $7\frac{1}{2}$ hr at an average pumping rate for the slurry which varied from about 250 to 300 gpm. The injection pressures, as measured at the wellhead, varied from about 1800 to 2000 psi. There was one brief halt after about 80 min when the flow was shifted from one waste tank to another (Fig. 9.9).

A total of 81,400 gal of waste and 2000 gal of wash water were mixed with a total of about 500,000 lb of solids out of the 732,540 lb on hand to give 121,805 gal of slurry injected. This was only about 6 lb of solids per gallon of liquid waste instead of 6.25 lb, the intended ratio.

This change in the proportion of solids to liquid in the mix as injected came about as follows. For all the experimental injections and the first operational injections, the pumping time of the mix was determined at 89°F, the standard temperature for the so-called API 1000-ft schedule. However, the shale at depths of about 900 ft at the disposal plant site is known to have a temperature of 64°F, and beginning with injection ILW-2A, the pumping times were measured at this temperature. This lower test temperature extended the pumping time sufficiently so that the retarder, delta gluconolactone (CFR-1), could be omitted, and still the mix had a pumping time of $7\frac{1}{2}$ hr. Only about 0.003 lb of CFR-1 per gallon of waste had been used in the previous mixes, so that no thought was given to the possibility that its omission would materially change any of the other physical properties of the mix. However, when injection ILW-2A was started, the mix was found to be almost too viscous to pump, and it was necessary to reduce the ratio of solids to only 6 lb/gal; even at this concentration the viscosity of the slurry was believed the highest of any of our injections. The average pumping pressures were from 1800 to 2000 psi, at rates of from 250 to 300 gpm, whereas for injection ILW-1A the injection pressure was about 1600 psi at a rate consistently as high as 300 gpm (Fig. 9.5).

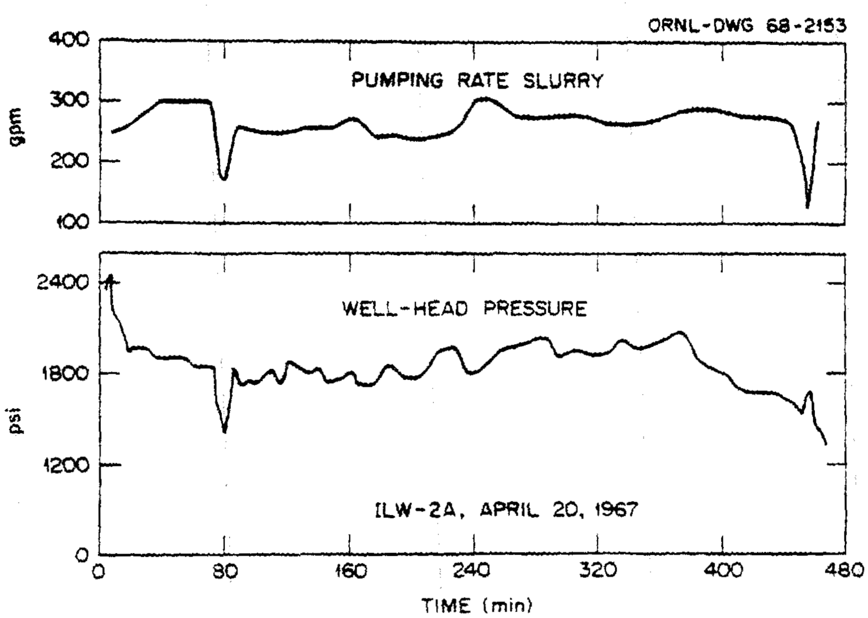

Fig. 9.9. Injection Pressure and Injection Rate During Injection ILW-2A.

The reduction in solids raised some doubts as to the possible separation of a fluid phase from the grout in the fracture, but bleedback from the injection well following injection ILW-2B amounted to only 6000 gal in $2\frac{1}{2}$ months, from a total slurry volume of about 400,000 gal.

The unexpectedly high viscosity was responsible for, or at least contributed to, another event which marked the ILW-2 injections. Following the injections the several observation wells were logged and activity was found in two of them, wells NW 100 and S 100. Well S 100 was found to be plugged with hardened cement, and the logging probe would not go below 879 ft, about the depth at which the fracture initiated in the injection well at a depth of 872 ft should have intersected it. The point of failure in well NW 100 could not be placed accurately but was also at about 870 ft. There can be little doubt that the two wells, tightly cemented into the shale above and below the plane of the fracture, were pulled apart when the overlying rock was uplifted; since the slurry injected on this occasion was particularly viscous we may surmise that the fracture was wider than usual. This type of failure had been anticipated, and all of the deep observation wells are valved shut at the surface while an injection is in progress.

INJECTION ILW-2B

A total of 285,000 lb of solids was mixed on April 21 and 22 and added to the estimated 230,000 lb left over from ILW-2A, giving a total of 515,000 lb. About 67,000 gal of waste was pumped from the Laboratory area to the waste storage tanks at the disposal plant.

Injection ILW-2B was started at 8:30 AM, April 24, 1967, and was completed in $7\frac{1}{2}$ hr. There was only one brief halt to clean the strainers between the waste storage tanks and the low-pressure pumps. A similar problem was encountered with the viscosity of the mix, and the proportion of solids to liquids was again reduced from 6.25 to 6.0 lb/gal.

A total of 64,345 gal of waste and 15,455 gal of water were mixed with 515,000 lb of solids. The solids were mixed with the water at a ratio of over 7 lb/gal in order to use up the remaining solids, because if solids are left in the bins more than a few weeks, they will set up. The total slurry injected in ILW-2B was 108,600 gal (Fig. 9.10).

The total slurry volume injected in both ILW-2A and -2B was 230,405 gal. The slurry contained 58,500 curies of cesium, 1050 curies of strontium, 442 curies of cobalt, and 194 curies of ruthenium. At the conclusion of the work the slot at 862 ft was overdisplaced with water so that injections ILW-3A and ILW-3B could be made into it.

In checking the equipment after the injection had been finished and the plant washed down, it was found that the tanks and the pump in the standby truck were slightly contaminated. Investigation showed that activity from the waste lines in the disposal plant had entered the lower ends of one or more of the fresh water lines used to clean out the slurry from the mixing and pumping equipment. Luckily it was possible to decontaminate the truck, and the piping at the plant has been modified to make a second such occurrence impossible.

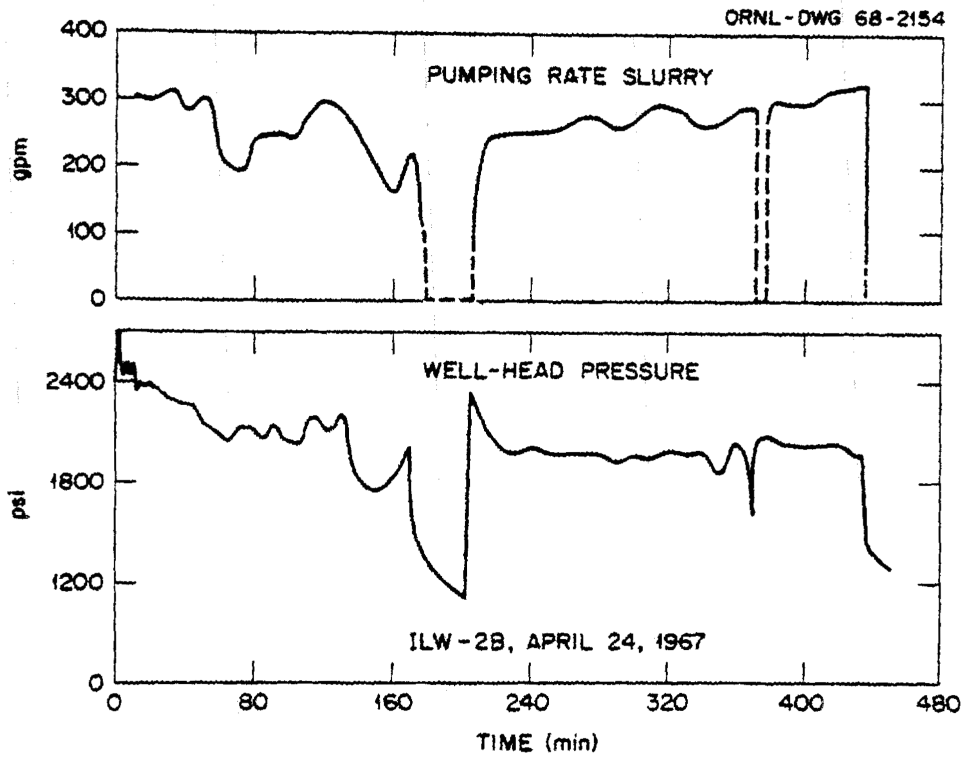

Fig. 9.10. Injection Pressure and Injection Rate During Injection ILW-2B.

LESSONS FROM INJECTIONS ILW-2A AND -2B

Although the two injections were made with a minimum of difficulty, several persistent minor troubles clearly remain to be solved.

More work needs to be done on mix formulation, not so much to reduce cost or to improve its quality as to take into account the practical problems of controlling the proportion of solids to liquid. Now that dry fly ash can be obtained, the mixing of the dry ingredients offers no serious problem, and the new weigh tank has appreciably reduced the labor involved. The liquid waste feeds to the mixer properly except when the filter in the feed line from the tanks plugs, and this problem has recently been greatly eased. But the control of the proportioning of blended solids to liquid waste still remains a problem. Although two Densometers have been installed so that one may be washed out and recalibrated while the other is in use, in practice this has not solved the problem. These instruments need to be easily accessible, but they must be well shielded (and thus inaccessible) because highly radioactive slurry is circulated through them. The viscous slurry in injections ILW-2A and -2B could not be washed out of them, even with acid. The mass flowmeter, also, does not retain its calibration. This is no reflection on these instruments, for, when the plant is operating, every minute $^3/_4$ ton of solids are mixed with some 250 gal of radioactive liquid in what is of necessity a shielded and relatively inaccessible cell. Probably the control of the proportioning can be improved, but it can never be exact.

In light of this difficulty it would seem wise to try to develop mixes which would still be satisfactory even though the slurries injected departed appreciably from the optimum proportions. The problem at present appears to rest on the fact that if the mix is slightly too rich in solids, it will be too viscous to pump properly; if it is too low in solids, there may be separation of a liquid phase before the grout has set up solid in the fracture. In general, additives which reduce the viscosity also promote phase separation and may also extend the pumping time. The relation between viscosity, phase separation, and pumping time needs to be investigated. We also need some basis for determining how important it is to avoid all phase separation and how to relate phase separation as measured in the laboratory with the phase separation that takes place under high pressure in the fracture deep underground. The core drilling tentatively scheduled for the spring of 1968 may shed some light on these problems.

10. Subsurface Distribution of Fractures and Grout Sheets

SUBSURFACE GEOLOGIC STRUCTURE AT THE PLANT SITE

The information presently available on the subsurface geologic structure at the site of the fracturing plant comes from the seven wells which have been drilled to the Rome-Conasauga contact. Five of these wells are NX core holes. One, the Joy well (see Fig. 7.14), was cored from the surface to a depth of 3263 ft, well into the Knox. The other four, wells S 100, NW 100, NE 125, and N 100, were drilled down to the top of the Rome following injection 5. These four wells were cored from a depth of about 800 ft, which is about sea level, to the Rome contact at about 240 ft below mean sea level (MSL). The other two wells, the injection well and well N 150, were drilled during the construction of the plant largely by cable tool and were appreciably larger in diameter than the NX core holes. For this reason it was possible to make neutron-gamma logs of these wells; however, because of the method of drilling, no cores were recovered.

The best information on the subsurface stratigraphy is found in the gamma-ray logs of the wells, which in every case were run from the land surface to the bottom. Figure 10.1 shows these logs from MSL +400 to −250 ft. The log of well S 100 is not shown below MSL −100 because the well was contaminated by activity from the grout sheet penetrated at this depth, and portions of the log of well NE 125 are missing for the same reason. In these cases the cores were used to locate the Rome-Conasauga contact, and where cores were available they were used to confirm the location of the contacts in the other wells.

The gamma-ray logs show the natural radioactivity of the rock, which is due to the presence of potassium, thorium, and uranium. These elements are all relatively abundant in the shale or other clay-rich beds (pen moves to the right) and low in the limestones and sandstone. The features of interest in the logs are the Conasauga-Rome contact, the "three beds of limestone" which mark the contact between the red shale (Pumpkin Valley) member of the Conasauga and the gray shale (Rutledge) member, and a few prominent limestone beds in the gray shale (A, B, and C) which can be correlated over short distances by inspection of the logs. It is not possible to correlate individual beds in the red shale, even between wells less than 100 ft apart.

The logs of the seven wells are arranged in Fig. 10.1 with the "southernmost" on the left and with the wells to the right progressively further "north," using the directions of the plant coordinates, in which "north" is 34° 12′ 51″ west of true north. This is convenient, since plant "north" is directly updip on the regional structure. The dip in this general area is about 20° to the south, and as the well logs span a north-south distance of 350 ft, the contacts should

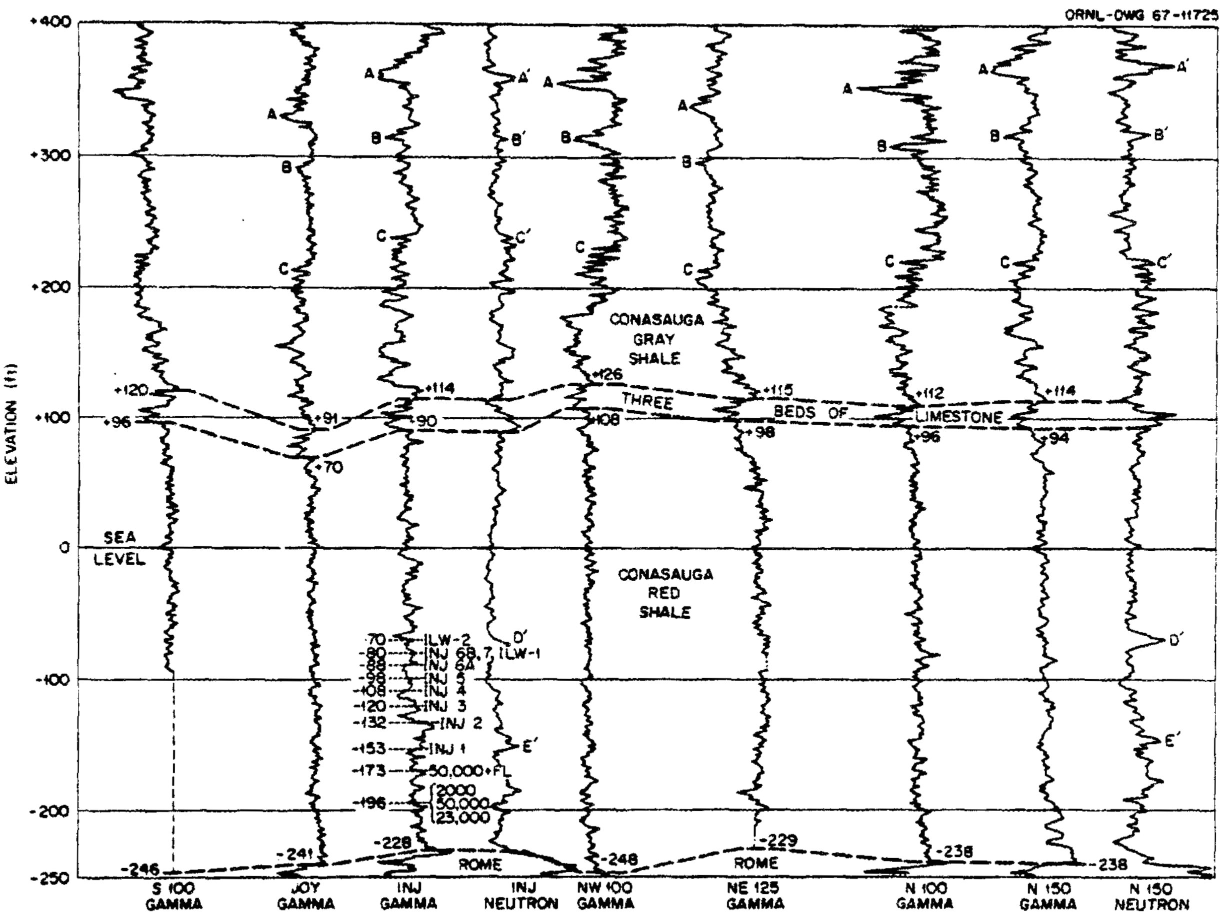

Fig. 10.1. Gamma-Ray and Neutron-Gamma Logs Showing Deep Subsurface Geologic Structure at Plant Site.

be about 125 ft higher in the log of well N 150 than in the log of well S 100. This is clearly not the case, and the principal contacts and the few beds correlated in the gray shale are all at very nearly the same elevation. The structure in the area covered by the wells must be very nearly horizontal. The possible exception is the slightly deeper position of the three limestone beds in the Joy well, but this appears to result from the red shale being somewhat thinner at this point. However, the bedding as seen in the cores has a dip which averages about 10°. The cores are not oriented, and it is possible that some of these dips are to the north and some to the south. The Joy well, the injection well, and well N 150 have been surveyed and depart no more than 1° from the vertical. Almost certainly the beds in the area of interest are essentially horizontal but locally have dips of 10 to 20° and even more where deformed by very small folds. Therefore, if the fractures and the grout sheets follow the bedding, they should be very nearly horizontal.

The neutron-gamma logs from the injection well and well N 150 are of interest for a somewhat different reason. These logs are made with a probe which contains a neutron source and, about 18 in. above it, a gamma-sensitive detector which records the log. The source is shielded from the detector, which "sees" only gamma rays which are formed in the wall rock by the capture of neutrons. The neutrons when emitted are too fast to be easily captured, but they are slowed down or moderated in the rock to thermal velocities, after which they can be captured. By far the most effective element in moderating the neutrons is hydrogen, which is present in small quantities in all the rocks. However, the shales are relatively rich in hydrogen, for the clay minerals contain combined water, and these rocks moderate a large proportion of the neutrons near the source, where they are captured; and, as this is somewhat distant from the detector, few of the resulting gammas reach it. The shales and other clay-rich beds consequently appear in the neutron logs as lows (pen moves left), and the neutron log is the mirror image of the gamma log, as seen at points A-A′, B-B′, and C-C′. The rocks have very low porosity and virtually no free water.

The neutron log highs at D′ and E′ require further explanation, for they do not correspond to lows in the gamma logs. They are believed to be due to the presence of chlorine, for sodium chloride is present in high concentration (up to 30,000 ppm) in some of the water pumped into fractures in the red shale and then recovered. Chlorine has by far the largest capture cross section of any of the elements commonly present in rocks, and the gamma rays resulting from capture are relatively penetrating. Therefore, in the absence of water, with its abundant hydrogen, which would moderate the neutrons close to their source, the salt produces a high on the neutron-gamma log. Whether the two points lettered D′ and the two lettered E′ represent the same beds is uncertain. Samples of the red shale will be analyzed for salt the next time cores are available.

CONSTRUCTION OF OBSERVATION, OR LOGGING, WELLS

By "observation wells" in this report we will mean wells used for gamma-ray logging carried out to locate the grout sheets. Each of a group of wells is logged subsequent to each waste injection, and new gamma-ray peaks in the logs indicate that the new fracture has intersected the well in question at the depth indicated. The prototype of these wells was well N 150. This well was drilled in May 1963 to a total depth of 1050 ft and cased with $2\frac{7}{8}$-in. tubing. The bottom 350 ft of the tubing was butt-welded to avoid the shoulders produced in the outside surface by couplings and was cemented into the shale with a rubber-base cement. The rest of the tubing was threaded and coupled and was cemented in with regular portland cement. The special treatment for the bottom part of the casing was to provide for the uplift of the shale above a grout-filled fracture. Some grout injections are known to produce multiple closely spaced parallel fractures with a total thickness of $\frac{1}{2}$ in., and the overlying rock is raised by this amount. If the casing were tightly cemented into the shale the casing would have to rupture at the point where the fracture intersected it, or alternatively the cement and perhaps the shale would have to break free from the casing for a distance great enough that the casing could stretch the required amount without passing the breaking point. The plastic cement was intended to yield and permit the movement of the wall rock past the casing. This it apparently did, but as we shall see it may also have crumbled. Samples of the cement, after they had set, were somewhat plastic but could be crumbled in the hand.

The problem of cementing in the casings of these observation wells was, on the one hand, to prevent rupture of the casing, and on the other hand to prevent the grout, or water squeezed out of the grout, from migrating up along the outside of the casing. Some yielding is required to prevent rupture of the casing, but the yielding should not produce channels which would permit radioactive materials to move up or down along the casing, for this could greatly complicate interpretation of the gamma-ray logs. Despite the precautions, there was considerable migration of activity up along the casing of well N 150, and subsequent wells were constructed somewhat differently.

CHARACTERISTICS OF THE LOGGING EQUIPMENT

The three original wells at the fracturing plant site (the injection well, well N 150, and well N 200 E) were logged by the Lane Wells Company with heavy, complex equipment. A wide variety of logs were run, but of these the gamma-ray logs proved to be by far the most useful; however, as described above, the gamma-neutron logs have certain points of interest. The rock density logs suggested that there might be a half dozen bedding-plane fractures in the lower 50 ft of the red shale immediately above the Rome, but the later coring has not confirmed this. The electrical logs were, as expected, of very little value.

In the summer of 1963 we purchased a trailer-mounted model VMVA Widco logger equipped for both electrical and gamma-ray logging. The characteristics of this instrument are material to an understanding of the logs.

Two probes containing scintillation detectors and preamplifiers were purchased with the instrument; one is 2 in. in diameter and the other is $\frac{7}{8}$ in. Their characteristics are similar, and both are referred to as probe No. 1.

The power supply, the main amplifiers, and the recording mechanism are housed in the trailer unit. The amplifier has seven sensitivity ranges, from 0.001 to 0.1 mr/hr; only the 0.02-, 0.05-, and 0.1-mr/hr ranges were used in obtaining the logs shown in this report.

The amplifier also has an adjustment labeled "sensitivity" which can be varied continuously from 10.0 (maximum response) to 0.0; at 0.0 there is still some response from the recorder. This sensitivity adjustment is normally used to calibrate the instrument, but since the logging of the grout sheets requires coverage of such a wide range of radiation fields, after the first few logs no attempt was made to calibrate the response, and the sensitivity control was used in an attempt to keep the response of the instrument within usable limits. In any case, once the normal range of the instrument has been exceeded, the response is no longer linear, and no logging to an absolute scale is possible.

Tests on probe No. 1 showed that with the amplifier set at 0.1 mr/hr and the sensitivity at 0.0, the least-sensitive setting possible, a field of 1.0 mr/hr gave full-scale deflection; with a field of 10 mr/hr the crystal-photomultiplier section of the probe saturated and the pen returned to zero. In mid-1964 a less-sensitive probe was secured, No. 2, with which, at the settings indicated above, full-scale deflection resulted from 3.0 mr/hr and saturation, or "reversal" of the log (marked "R" on some of the logs), occurred at 14 mr/hr. This extended the useful range of the instrument somewhat, but with injection 7, in October 1966, the specific activity of the grout sheets was such that the limits of the second probe were considerably exceeded, and a third much less-sensitive probe was procured. To date no logging has been done with the third probe.

Other variables in the logging are the time constant and the logging speed. In all the logs shown the time constant was either 5 or 10 sec, and the logging speed was about 10 fpm. Shorter time constants or even slower logging speeds do not change the character of the logs materially.

RESULTS OF LOGGING WELL N 150

The first log (see Fig. 10.2), run in late 1963 some months after the well was drilled, shows the natural variation in activity in the beds of red shale. The peaks and lows shown are 2 to 5 ft thick, about the limit of reliable resolution when logging the natural radioactivity of shales.

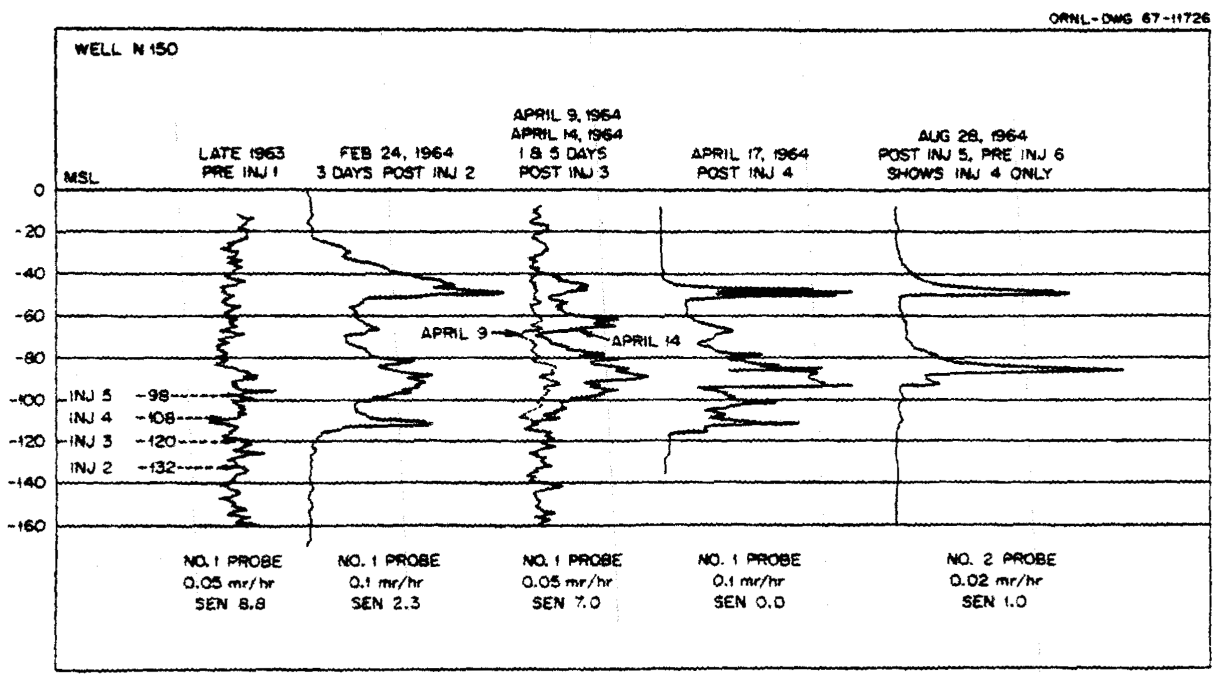

Fig. 10.2. Gamma-Ray Logs, Well N150, Late 1963 to Aug. 28, 1964.

The logs in any one well, with care, are reproducible, but no correlation of beds within the red shale is possible between wells even less than 100 ft apart. With the setting shown in the figure the logger is at least roughly in calibration, and the field varies from about 0.04 to 0.07 mr/hr.

Injection 1, the first experimental injection with simulated waste, contained no radioactive material and consequently could not be picked up by gamma-ray logging. The mix for injection 2 was tagged with 30 curies of ^{198}Au Wednesday afternoon, February 19, 1964. The injection was first attempted on February 20; but after 6000 gal had been pumped into the fracture, the screen in the waste line between the tanks and the mixing (primary) pumps clogged, and the rest of the injection had to be postponed. No change was noted in the radiation field in well N 150 during the first attempt. The next day the injection was resumed and an additional 16,000 gal of "waste" was pumped into the fracture for a total for both days of 22,500 gal, including wash water. Activity showed up in well N 150 during the second day of pumping. The log shown was made on February 24, three days after the pumping had stopped and five days after the 30 curies of gold had been added. The gold would have decayed through nearly two half-lives by this time, and only about 10 curies was present when the log was made.

Observations made with the logger during the injection showed that the activity first reached the well at about MSL −112 ft, about 20 ft above the level of the slot in the injection well, and that it then worked its way up along the casing for nearly 100 ft, reaching MSL −20. There are peaks at − 112 ft, the observed point of first arrival, and from −100 to −80 ft and again at −50 ft. Except for the point of first arrival, these peaks are believed to represent weak points in the rubber-base cement in which pockets of radioactive liquid collected. The peak activity at −50 ft represents a field of nearly 1.0 mr/hr. The fracture, therefore, is believed to have intersected well N 150 at MSL − 112 ft, about 20 ft higher than the slot in the injection well, 150 ft to the south, although the evidence is not conclusive.

Injection 3 was made on Wednesday, April 8, 1964, and consisted of 54,745 gal of grout made from synthetic waste, clay, and cement and containing 74 curies of ^{137}Cs and minor amounts of other nuclides. The injection of this grout was followed by the injection of 10,509 gal of nonradioactive grout for a total of 65,314 gal. No activity was observed in well N 150 during the injection or when the well was logged again the next day. However, when the well was logged on April 14, in preparation for injection 4, activity was found in the well from MSL −100 to −40. There was no peak at −112, as there had been following injection 2, but the peaks from −100 to −70 and from −50 to −40 strongly resemble the peaks formed by the second injection. A new peak, however, was formed in the interval between MSL −70 and −60 ft. The maximum field opposite the peaks of activity was of the order of 0.05 mr/hr, but in any case these peaks, resulting from 74 curies of ^{137}Cs, were lower than those resulting in the previous injection, from 10 curies of gold. In part this represents the much greater adsorption on the wall rock of cesium than of gold.

The next log was made on April 17, 1964, three days after injection 4. The total volume injected was 60,144 gal, containing 50 curies of ^{137}Cs and minor amounts of other nuclides. Observations made with the logger while the injection was in progress showed that activity appeared in well N 150 as the grout was being injected, first at MSL −112, and within a few minutes had formed peaks at −88 and −50 ft. These peaks had sufficient activity to saturate the probe and make the logs reverse; so the log does not clearly show the true distribution of the grout.

Injection 5, consisting of 211,275 gal of slurry containing 143 curies of ^{137}Cs and 4099 curies of ^{144}Ce, was made on May 28, 1964. It did not reach well N 150. Shortly after this date probe No. 2, a less-sensitive probe, was received, and on August 28 a log made with this probe gave a much clearer picture of the radiation field in well N 150. This log shows two sharp peaks, one at −88 ft and another at −50 ft. The higher of these peaks represents a field of roughly 10 mr/hr. Injection 4 was made at an elevation of −108 ft, so that the fracture apparently had broken upward about 20 ft between the injection well and well N 150.

In injection 6 troubles were encountered with the mix equipment, the pump, and the well head, and the injection was made in two parts. Injection 6A, on May 19, 1965, consisted of 5670 gal of grout and an additional volume of 18,800 gal of wash water; 6B, on May 22, consisted of 86,543 gal, largely of grout. Injection 6A was made into a slot at an elevation of −88 ft and 6B into a slot at −80 ft, which was left open at the close of the injection. The total activity in both parts of the injection was 1562 curies of ^{137}Cs and minor amounts of other nuclides (Fig. 10.3).

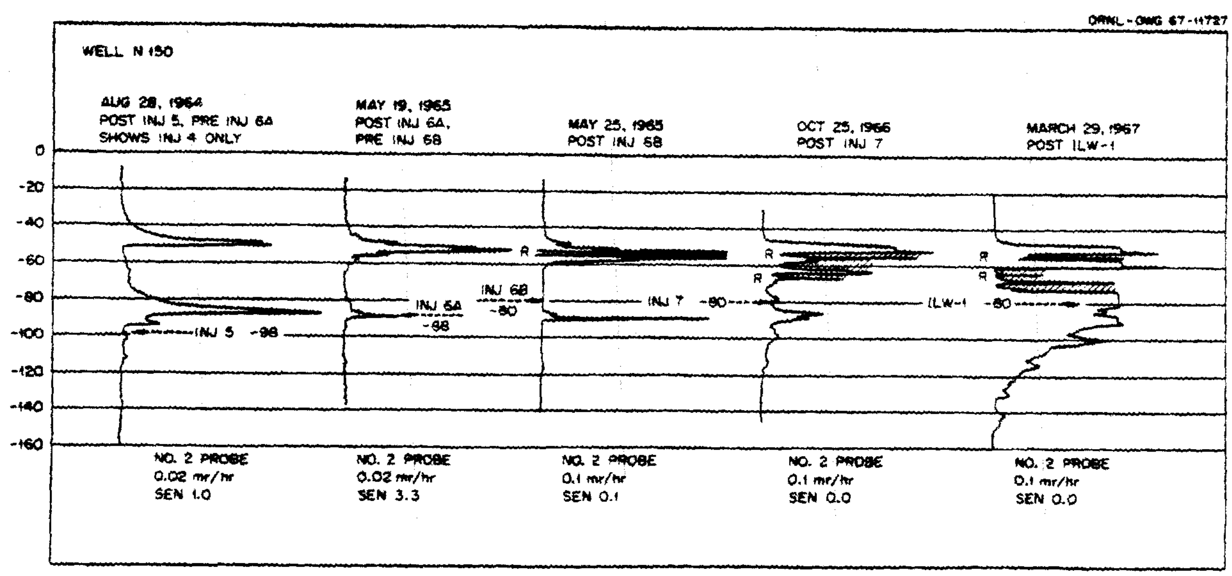

Fig. 10.3. Gamma-Ray Logs, Well N150, Aug. 28, 1964, to Mar. 29, 1967.

A log made on May 19, after the grout of injection 6A had been pumped but prior to the injection of the wash water, showed a reduction in the activity peak at −86 ft and a possible slight increase in the peak at −50 ft. It is improbable that any activity from this injection reached the well at −50 ft, but we have no convincing explanation of why the peak at −88 ft appeared lower in this log than in the essentially identical log of August 28, 1964.

The next log, run on May 25, 1965, after injection 6B had been completed, showed a marked increase in activity both at −88 ft (note mr/hr setting) and also at −50 ft, where the log shows two reversals. Injection 6B was made at an elevation of −80 ft. There is at least a possibility that this grout sheet came past the observation well in a fracture at −50 ft; if so an important part of injection 4 also followed this plane of weakness. Alternatively, the peaks at −50 and −88 ft represent weak places in the rubber-base cement in which a liquid phase from the grout sheets collected.

The next log, on October 25, 1966, shows the results of injection 7. This injection, made on August 16, 1965, into the same slot as injection 6B, consisted of 123,411 gal of grout containing 3358 curies of ^{137}Cs and minor amounts of several other nuclides. The sensitivity is virtually the same as the log of May 25, 1965; so the decrease in height of the peak at −88 ft is probably genuine. Whether this is due to decay or migration of fluid is unknown. Three new peaks at −54, −60, and −66 ft, which show up as reversals in the log, represent the grout from injection 7, which intersected the observation well at these depths. This grout was injected into a slot in the disposal well at −80 ft.

The next log, on March 29, 1967, was made after the injection of ILW-1, also into the slot at −80 ft. This log shows an increase in activity between −120 and −80 ft that is almost certainly due to migration downward along the well casing of liquid squeezed out of the grout, and what may be a new peak shows up as a reversal of the log at −70 ft. The accuracy of the depth measurements is not such that the new peak can be placed precisely, particularly when the sensitivity of the logger is so overloaded. About all one can say is that additional activity appears to have reached the observation well in the interval between −70 and −50 ft as the result of injection ILW-1.

In general we may conclude the following about the injections:

Injection 2 intersected well N 150, probably at −112 ft, 20 ft above the point of injection, although activity was present outside the well casing as far up as −20 ft.

Injection 3 came near the observation well, but the fracture did not actually intersect it. Radioactive liquid from the grout sheet had reached the well five days after the injection and appeared outside the well casing over much the same interval as injection 2, although the peak at −112 ft was missing.

Injection 4 intersected the observation well and produced a new peak at −88 ft, 20 ft above the elevation at which it was injected, and greatly increased the intensity of the old peak at −50 ft.

Injection 5 did not reach the observation well.

Injection 6A probably did not reach the observation well.

Injection 6B probably did reach the observation well, intersecting it at −55 ft, 23 ft above the depth of the injection.

Injection 7 intersected observation well N 150 in the interval between −70 and −50 ft, also roughly 20 ft above the depth of injection.

ILW-1, injected into the same slot as injection 7, apparently reached the observation well, reinforcing the peaks between −70 and −50 ft; however, the record is not clear.

RESULTS OF LOGGING WELL N 100 (Fig. 10.4)

Well N 100 is located on a north-south line joining the injection well with well N 150 and, as its number suggests, is located 100 ft north of the injection well and 50 ft south of well N 150. The well was drilled in August 1964, following injection 5 and prior to injection 6A. It was cored from about sea level down through the lower Conasauga and a short distance into the Rome. To our surprise no radioactive grout seams were intersected by this well, although it did flow salt water slowly after the drilling was completed, presumably from one of the fractures formed during the water-injection tests. Injection 1 contained no radioactive material, and by mid-1964 the ^{198}Au in injection 2 had long since decayed away; so the fractures formed by these injections could have been penetrated without our knowledge. The grout seams formed by injections 3, 4, and 5 should still have been unmistakable, particularly in the gamma-ray log of the well; however, as injection 5 was not found at well N 150, there was no particular reason to expect it in well N 100. But injections 3 and 4 were found at or very near well N 150, and the failure to find them at well N 100 was an unexplained surprise.

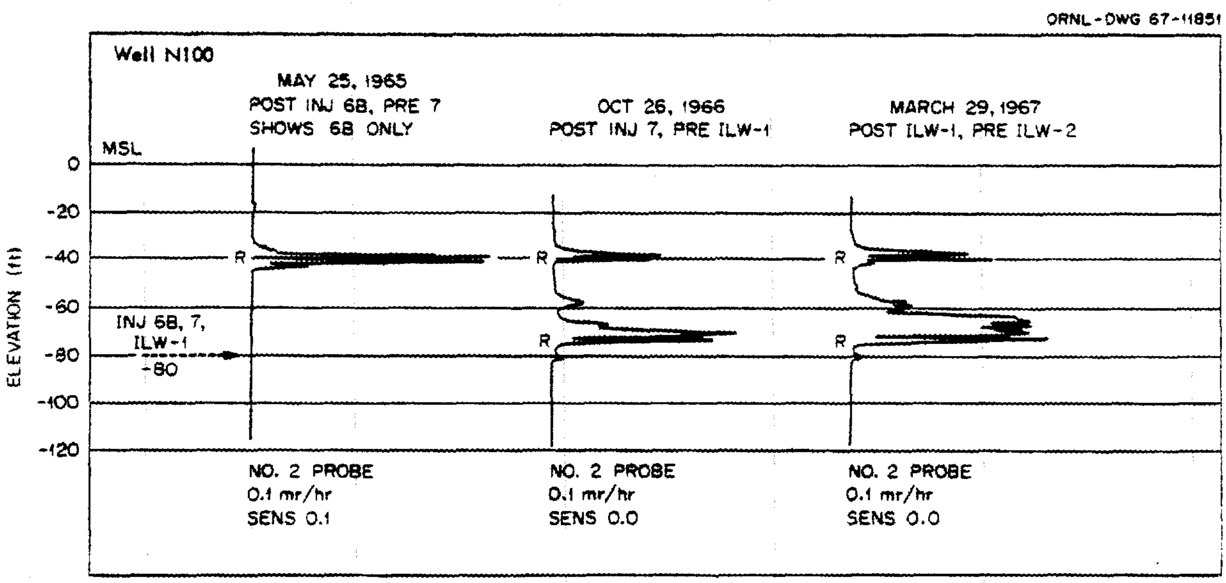

Fig. 10.4. Gamma-Ray Logs, Well N100, May 25, 1965, to Mar. 29, 1967.

A possible explanation was provided by the log of well N 100 made on May 25, 1965, subsequent to injection 6B. This injection was made at an elevation of MSL − 80 ft but showed up as a thin sharp peak in well N 100 at MSL − 40, showing that this fracture had broken 40 ft up across the bedding in moving 100 ft to the north. This also places this fracture 15 ft higher in well N 100 than it appeared to be in well N 150. Combined with the failure to find injections 3 and 4 in well N 100, the deflection of the fracture suggests that there is a barrier from roughly MSL − 120 to − 40 which forced injections 3 and 4 to detour around it to reach well N 150 and injection 6B to detour over it. The barrier could well be a zone of tightly folded rock, although there is no direct evidence that such a zone exists.

It is interesting to note the sharp narrow peak in the gamma-ray log formed where injection 6B intersects well N 100; there is no evidence that the grout, or liquid squeezed out of the grout, migrated up or down the well casing. This well, like the other core holes, was cased with $1\frac{1}{4}$-in.-ID steel tubing cemented with neat portland cement. This appears to be greatly superior to the rubber-base cement used in well N 150, although there may be danger of rupturing the tubing if one of the fractures intersects the well at a coupling.

The next log of well N 100 was made on October 26, 1966, after injection 7. This injection, like injection 6B, was made at an elevation of − 80 ft and intersected well N 100 at − 70 ft, 30 ft below the point of intersection of injection 6B. Injection 7 therefore appears to have broken through the barrier after having been deflected upward only 10 ft. This is certainly not the type of pattern one would anticipate, although the evidence is clear that this is what must have happened.

The next log of well N 100 was made on March 29, 1967, following injection ILW-1, which, like the two preceding injections, was made at − 80 ft. The log shows clearly that additional activity reached well N 100 at − 70 ft along the same fracture followed by injection 7. No part of injection 7 or injection ILW-1 appears to have followed the fracture formed by injection 6B.

RESULTS FROM LOGGING WELL NW 100 (Fig. 10.5)

This well was drilled during late August and early September 1964. No grout was found in the cores, and gamma-ray logging showed no activity above background. The well was then cased with $1\frac{1}{4}$-in.-ID tubing, which was cemented in with neat portland cement. Logging of the well following injection 6B showed no signs of this grout seam, but on October 26, 1966, about a year after injection 7, logging showed a high peak of activity at MSL − 75 ft and two minor peaks at − 52 and − 87 ft. Injection 7 was made into a slot in the injection well at − 80 ft, so that in traveling 100 ft to the NW the fracture moved up about 5 ft.

The next log, on April 3, 1967, followed injection ILW-1, which also was made into the slot at − 80 ft. This log shows a possible increase in activity in the peak at − 75 ft (note the more marked reversal of the recorder) and a new minor peak at − 63 ft. There is a strong presumption that ILW-1 followed much the same fracture as injection 7, but that it did not reach well NW 100 in force.

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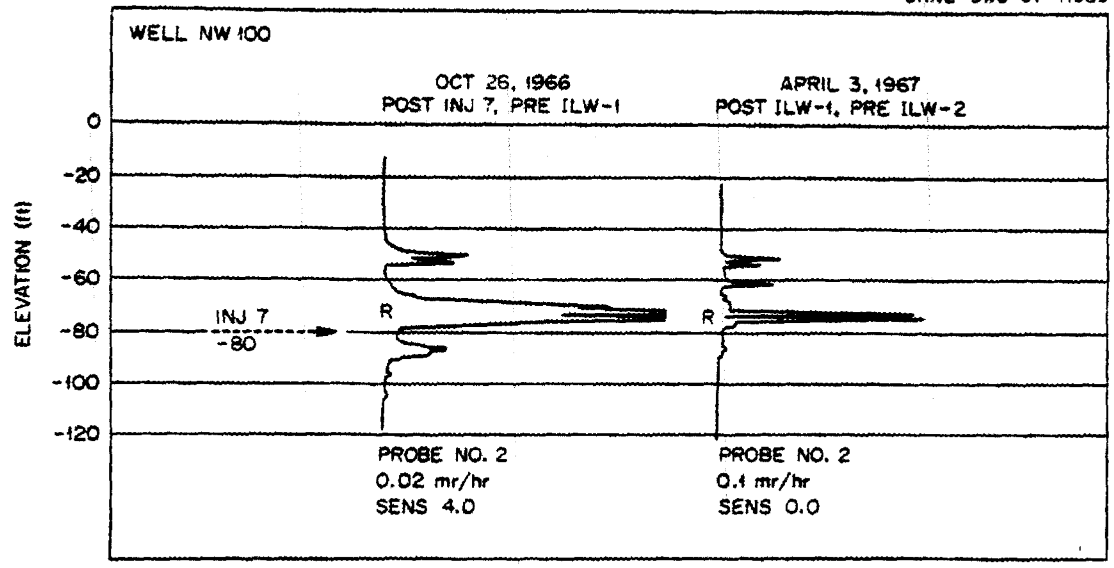

Fig. 10.5. Gamma-Ray Logs for Well NW 100.

INFORMATION FROM WELL NE 125 (Fig. 10.6)

This well was drilled in September and October 1964 and was cored from about mean sea level down into the Rome at about MSL −229. Three of the fractures were identified in the cores: injection 1, as two thin seams of white attapulgite clay at MSL −132.9 and −133.1 ft; injection 2, as a seam of cement and clay 0.03 in. thick at MSL −93.0 ft; and injection 5, as six thin sheets of cement and clay. These were: (1) a sheet 0.035 in. thick at −87.4 ft, (2) a sheet 0.1 in. thick at −86.5 ft, (3) two sheets, each 0.1 in. thick, at −86.3 ft, (4) a sheet 0.06 in. thick at −84.6 ft, and (5) a sheet 0.27 in. thick at −84.4 ft (see Fig. 10.7).

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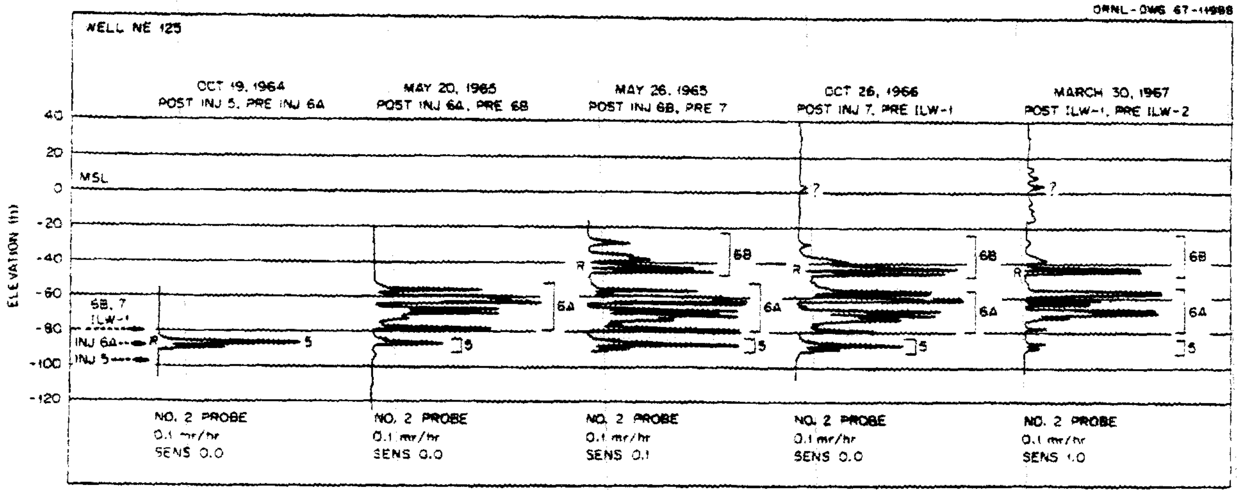

Fig. 10.6. Gamma-Ray Logs for Well NE 125.

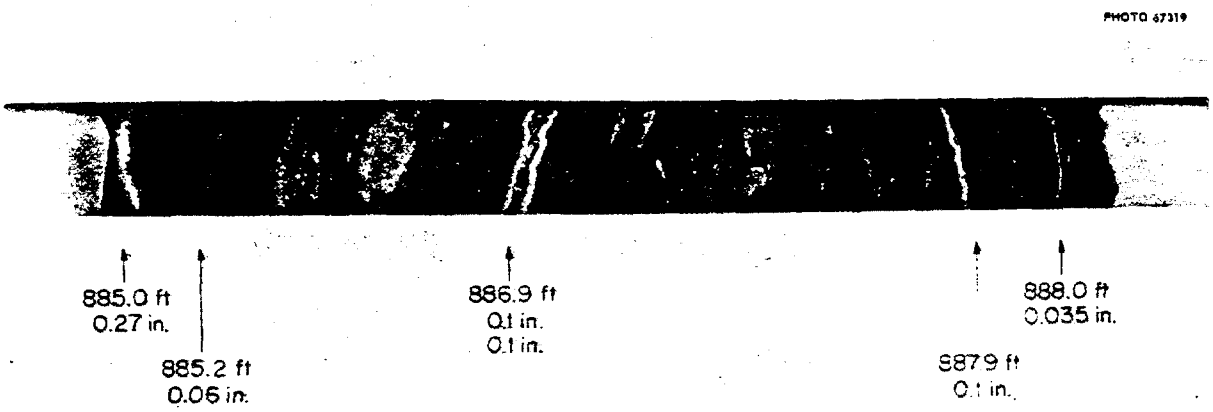

Fig. 10.7. Well NE 125, Core Showing Injection 5.

Injection 1 was made into a slot at an elevation of MSL −153 ft; since it was found at an elevation of −133 ft, it rose 20 ft in traveling 100 ft to the northeast.

Injection 2 was made into a slot at an elevation of MSL −132 ft; since it was found at an elevation of −93 ft, it rose 39 ft in traveling 100 ft to the northeast.

Injection 5 was found at an average elevation of MSL −86 ft; since it was made into a slot at an elevation of −98 ft, it rose 12 ft in traveling 100 ft to the northeast.

The first log of well NE 125, made on October 19, 1964, shows injection 5 as a single peak at an elevation of MSL −88 ft; depths determined by logging are less accurate than depths determined during coring operations. The apparent double peak in the log comes from saturation and reversal of the recording equipment.

The second log was made on May 20, 1965, the day following injection 6A. This log shows several peaks, with reversals between MSL −56 and −80 ft. As injection 6A was made at an elevation of MSL −88 ft, this injection also had come up about 12 ft in reaching well NE 125.

The third log was made on May 26, 1965, shortly after injection 6B, and shows several new peaks between MSL −30 and −50 ft, with the largest showing a reversal at MSL − 44. This injection was made at an elevation of MSL −80 ft, so that it came up 36 ft in traveling out to well NE 125.

Logs were also made on October 26, 1966, following injection 7, and on March 30, 1967, following ILW-1, but neither of these showed any large new peaks. Several small peaks were noted in these logs at MSL +2, +9, and +14 ft, but whether these were formed at the time of injection 6B or later was not clear.

In summary we can say with confidence that injections 1, 2, 5, 6A, and 6B reached well NE 125 but that injections 3, 4, 7, and ILW-1 did not.

INFORMATION FROM WELL S 100 (Fig. 10.8)

This well was drilled in late November and early December 1964. It was cored from about MSL through the top of the Rome at about MSL −246. Injections 3, 4, and 5 were identified in the cores; no evidence was found of injections 1 and 2.

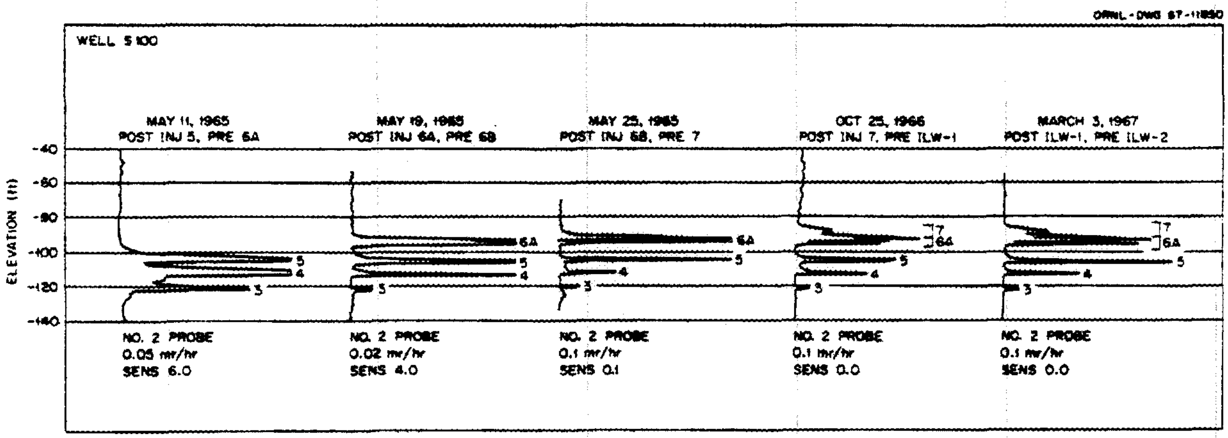

Fig. 10.8. Gamma-Ray Logs, Well S 100, May 11, 1965, to Mar. 3, 1967.

Injection 5 was found at an elevation of −101.6 ft as measured in the core and at −105 ft as measured by the logger. The depths as measured in the logs seem to average about 0.5% deeper than the more accurate measurements made in the cores, although the difference is not yet sufficiently well established to apply a correction factor to the logged depths. Injection 5, as seen in the core, was a single irregular fracture containing broken pieces of shale and varying in thickness from 0.60 to 0.65 in.; the average thickness was about 0.625 in. Injection 5 was made at an elevation of −98 ft in the injection well, so that it went down about 3 ft in traveling to well S 100.

Injection 4 was found at an elevation of from −109.3 to −109.1 ft as seen in the cores and −112 ft as seen in the logs. In the core it appeared as one very irregular major sheet with several minor sheets; the aggregate thickness was 0.30 in. (see Fig. 10.9). Injection 4 was made at an elevation of −108 ft in the well, so it went down about 1 ft in traveling to well S 100.

Injection 3 was found at an elevation of −118.4 ft in the core and at −122 ft in the log. The grout sheet appeared in the core as a single layer about 0.35 in. thick (see Fig. 10.10). Injection 3 was made at an elevation of −120 ft in the injection well, so that it came up nearly 2 ft in traveling out to well S 100.

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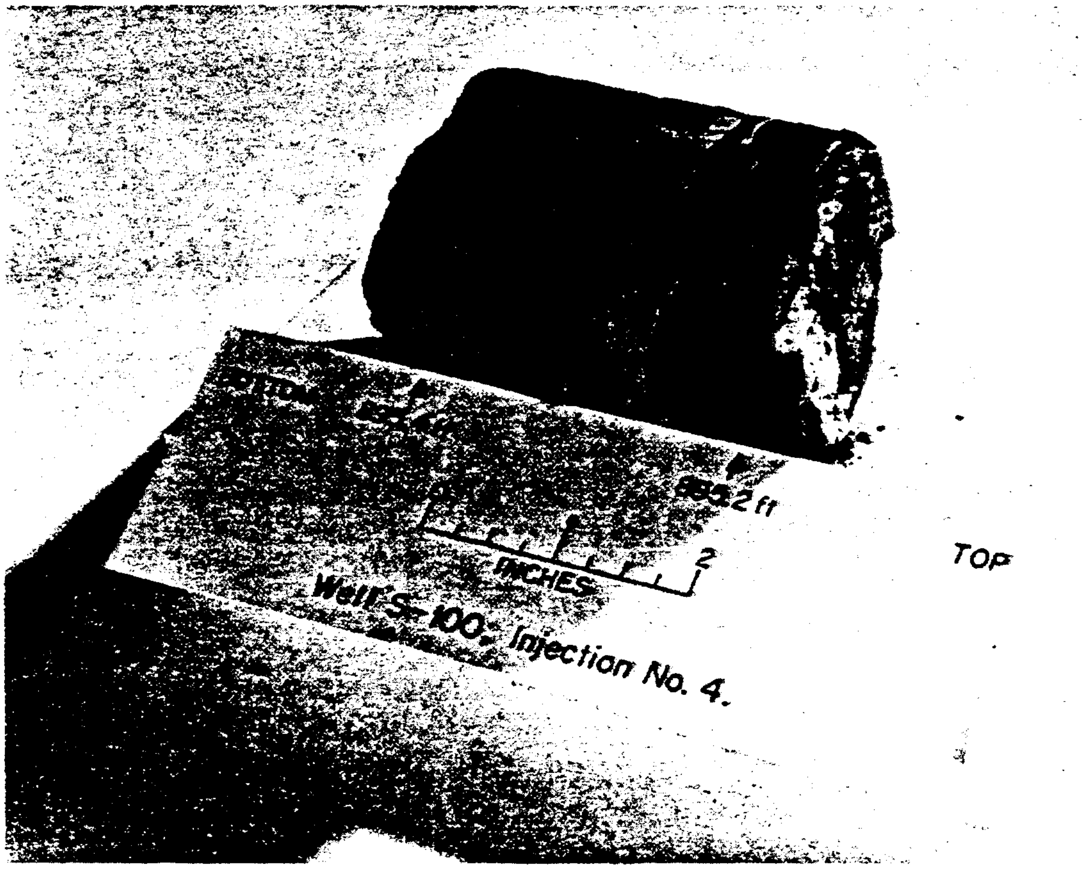

Fig. 10.9. Well S 100, Core Showing Injection 4.

The first complete log of well S 100 was made on May 11, 1965, following injection 5 but prior to injection 6A. Injections 3, 4, and 5 can easily be identified in the log.

The second log was made on May 19, 1965, following injection 6A and prior to injection 6B. Injection 6A formed a sharp, narrow peak at − 95 ft. It was injected at − 88 ft, so it moved down 7 ft in traveling from the injection well to well S 100.

The third log was made on May 25, 1965, shortly after injection 6B. There is no evidence that any radioactive material from this injection reached well S 100.

The fourth log was made on October 25, 1966, following injection 7. Activity from this injection is seen in the log of well S 100 at an elevation of about − 90 ft. The injection was made into a slot at − 80 ft, so the fracture went down 10 ft in moving out to well S 100.

The fifth and last log of this series was made on March 3, 1967, following injection ILW-1. No evidence of any additional activity was found in this log, and ILW-1 apparently did not reach well S 100. ILW-1 was injected into the same slot as injections 6B and 7.

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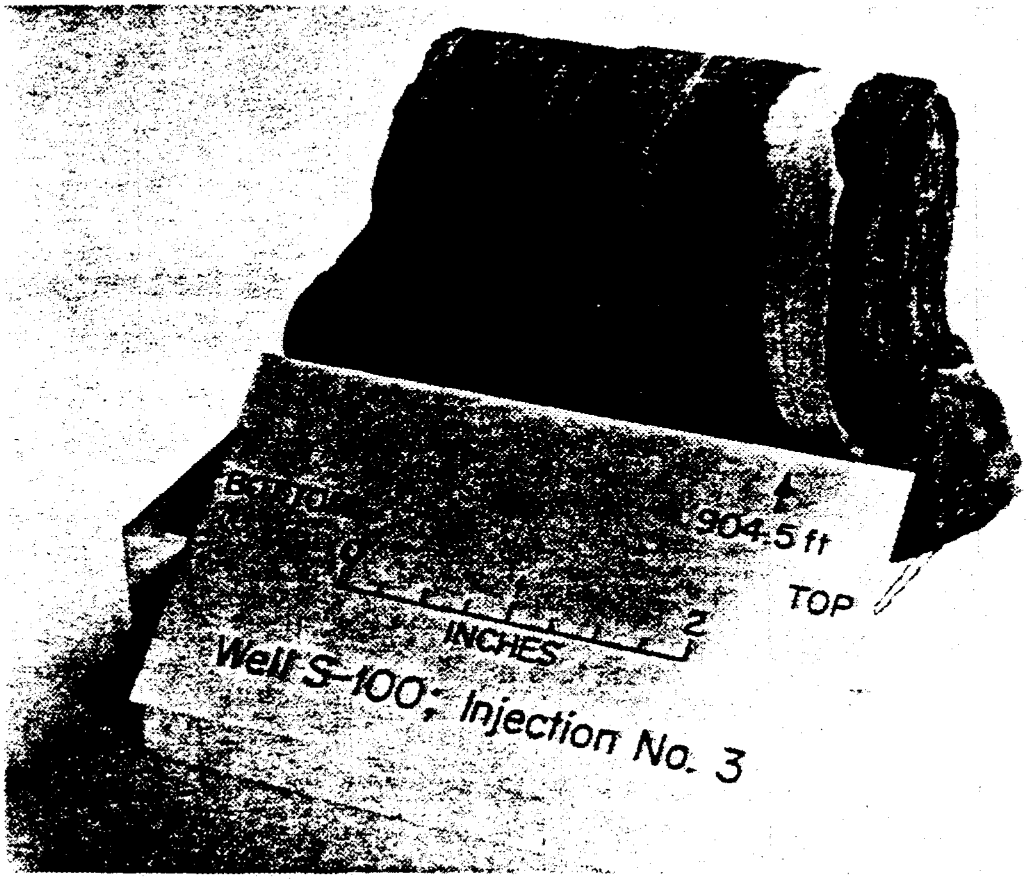

Fig. 10.10. Well S 100, Core Showing Injection 3.

INFORMATION FROM THE JOY WELL (W 300) (Fig. 10.11)

The Joy well was drilled during the summer of 1961, and a $1\frac{1}{4}$-in.-ID casing was cemented in about a year later. There is reason to believe that the cementing job was not well done and that it may be weak in places. The top of the casing was bent in the winter of 1963–64, and the well was not logged until the summer of 1964, after injection 5 and prior to injection 6A. The log of August 31, 1964, shows two sharp peaks, at MSL -110 and -99 ft, and a minor peak at MSL -90, above which the level of activity falls off gradually. The peak at -110 ft is believed to represent injection 4, which was made at an elevation of -108 ft, and the peak at -99 ft is believed to represent injection 5, which was made at -98 ft. If this is so, then these two fractures traveled nearly horizontally to reach the Joy well, 300 ft west of the injection well. The minor peak at -90 ft is believed to represent water squeezed out of the grout of injection 5, which migrated up along the casing.

The second log was made on June 1, 1965, following injection 6B and prior to injection 7. Two new peaks are present in this log. One is at -105 ft, between the two earlier peaks at

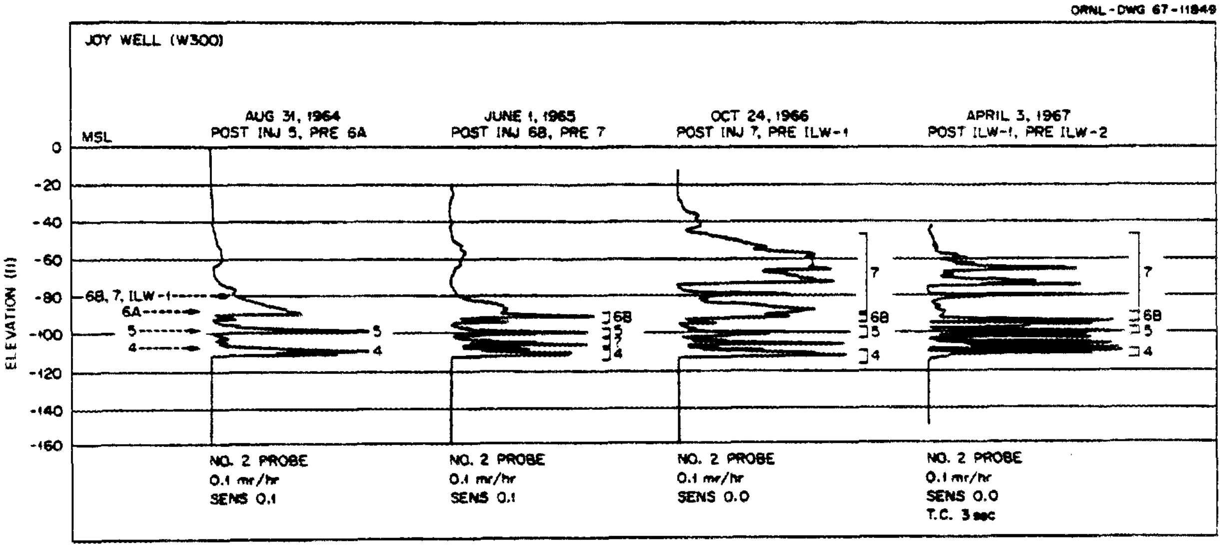

Fig. 10.11. Gamma-Ray Logs, Joy Well (W 300), Aug. 31, 1964, to Apr. 3, 1967.

– 110 and – 99 ft. No explanation is advanced for this peak. The other is at – 91 ft and is believed to represent injection 6B, which was made at – 80 ft. It is believed that not enough grout and wash water were contained in injection 6A to reach the Joy well, 300 ft away, although the elevation of this peak corresponds more closely to injection 6A, which was made at – 88 ft.

The third log, made on October 24, 1966, following injection 7, shows several new peaks between – 90 and – 57 ft, with some activity as high as – 40 ft. From this record it is impossible to say whether injection 7 intersected the Joy well as a series of sheets over a span of nearly 40 ft or whether radioactive grout or water migrated up along the casing, although this latter explanation appears more probable. If the activity did move along the casing through the weak cement, it is not possible to determine just where the main fracture intersected the well, but it may have come in on top of 6B, for both injections were made into the same slot.

The next log of the Joy well was made on April 3, 1967, following injection ILW-1. This log was made with a time constant (T.C.) of only 3 sec, shorter than the 5- or 10-sec time constant normally used, and with a logging speed of only 5 to 8 fpm. This gives a somewhat "busier" log than the log of October 24, 1966, with many more sharp peaks and reversals. The activity around the well is the same in the two logs, and injection ILW-1 did not reach the Joy well. However, the log of April 3, 1967, illustrates the need both for a less-sensitive probe and for an expanded vertical logging scale. Attempts are in hand to provide both.

11. Surface Uplifts Resulting from Experimental Injections

INTRODUCTION

The surface uplift measurements obtained from the second fracturing experiment (see Chap. 3) indicated that although the pattern of uplift cannot be used as a guide to the underground location of the grout sheet, it may suggest that a horizontal rather than a vertical fracture has been formed. Furthermore, uplift measurement is one of the very few methods available for collecting data on the behavior of the rocks overlying the injected grout. For these reasons, an extensive network of bench marks was installed at the site of the hydraulic fracturing plant, and procedures were instituted for making periodic elevation surveys during the course of the experimental injections.

In this chapter, only the results obtained from the first seven experimental injections at the fracturing plant will be described and analyzed.

EXPERIMENT AND PROCEDURES

Bench Marks

The primary monuments consist of a 1-ft-long, $^5/_8$-in.-diam stainless steel bar embedded in concrete. The concrete was poured in place in 18-in.-diam holes drilled with an earth auger. These holes were dug to a depth of 9 to 10 ft except where the rock base was reached at a shallower depth. Most of the monuments were constructed with the tops about level with the ground surface; a few were built with their tops below ground level to protect them from being run over.

Several auxiliary bench marks consisting of lag bolts set into the roots or lower parts of large trees were also installed at the site. The purpose of these bench marks was to provide a check on the stability of the concrete monuments. However, this originally intended use was forgotten, and they were incorporated into the lines of traverse and leveled along with the bench marks.

Bench Mark Net

The monuments were laid out in the field on two lines crossing at approximately 60° near the injection well (Fig. 11.1). The radial lengths of these lines are: line A to the northeast, 1700 ft; line B to the east, 1800 ft, and connecting to an existing line from the second fracturing ex-

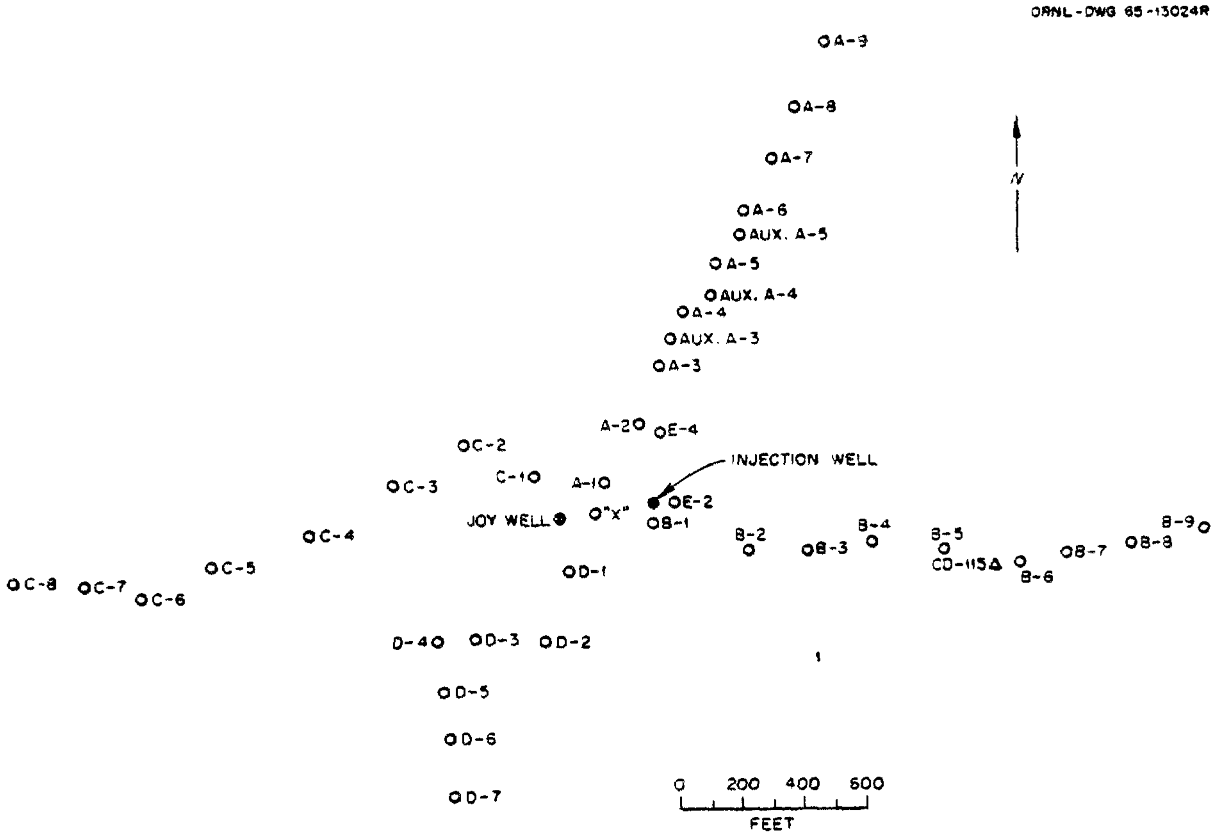

Fig. 11.1. Layout of Leveling Bench Marks at the Hydraulic Fracturing Plant (as of 1966).

periment, thereby effectively extending it another 1400 ft; line C to the west, 2000 ft; and line D to the southwest, 1100 ft. The topography at the hydraulic-fracturing plant not only limited the length of line D but also made it impractical to provide a more adequate areal coverage of the site. It would have been very difficult to construct and accurately to survey lines running to the northwest and southeast. Wherever possible, the locations of the lines and of the individual monuments were chosen adjacent to existing roads. This provided easy access for construction and eliminated many line-of-sight interferences.

The bench marks were spaced about 200 ft apart because this appeared to give as much detail for the plotting of profiles showing uplift as was warranted by the precision of the leveling. Temporary turning points, in the form of wooden stakes driven in the ground each time the line was run, were used to shorten the length of the sights, which rarely exceeded 50 ft.

The size of the required leveling net can be estimated by assuming a circular injection sheet. The radius of the circular area on the surface to be observed (R') is then given by

$$R' = R + H \tan \alpha + 20\% \, (R + H \tan \alpha) + 2L \, , \tag{1}$$

where

R = maximum expected radius of the injection sheet,

H = depth of injection,

α = angle of draw,[1]

L = distance between stations, and $2L$ is included to ensure that two stations are beyond the limit of movement in order to accurately tie down absolute movements,

20% = experimental contingency included to allow for the inherent unpredictability of geologic materials and possible deviations from circularity of the injection.

For the experimental injections, $R = 400$ ft, $H = 1000$ ft, and $L = 200$ ft; thus

$$R + H \tan \alpha = 400 + 1000 \times 0.7 = 400 + 700 = 1100 ,$$

and from Eq. (1),

$$R' = 1100 + 220 + 400 = 1720 ,$$

giving a required radial length of survey line of 1720 ft. This suggests that the bench mark net was just adequate to cover the anticipated area of uplift. Since the current series of operational injections involves volumes of approximately 100,000 gal, the expected radius of injection (R) may be longer than 400 ft. Based on this and the analysis of the uplift data obtained from the first seven injections (see below), lines A and C have each been extended by the addition of three bench marks. These two lines are now approximately 2400 ft long.

Surveying Equipment and Techniques

For the first traverses, a dumpy engineer's level was used; later, a Wild N-3 precision level was obtained. With sufficient time and care, the dumpy level can give as accurate results as the Wild level, so that the better instrument served primarily to save time, not to improve the results. An Invar leveling rod with 0.01-ft divisions was used throughout. The technique adopted and used at every sighting was as follows:

1. The instrument was erected at a point midway between the front and back sights and very carefully leveled.
2. The three cross hairs in the instrument (level and two stadia hairs) were read to 0.001 ft by estimating the last figure.
3. These three readings were averaged, and the mean was compared with the level reading. If this reading departed from the mean by 0.001 ft or more, the entire set of readings was repeated; if not, the calculated mean, calculated to 0.0003 ft, was recorded as the sight reading.

[1] This is a concept from subsidence engineering and is defined as the angle made by the vertical and a line drawn from the limit of surface disturbance to the edge of the underground workings. It is nearly universally found to be between 34 and 39° and is usually assumed to be 35° in areas where it has not been previously determined. See K. Wardell, "The Minimization of Surface Damage by Special Arrangement of Underground Workings," *Proc. European Cong. on Ground Movement, Leeds, April 9–12, 1957.*

4. Any error of closure was balanced by averaging the outbound and inbound differences in elevation between each of the points in the closed traverse.

The accuracy of the determination of the difference in elevation of two adjacent bench marks therefore should be about 0.001 ft. Examination of the data shows that only in a few percent of the readings do the determinations on the outbound and inbound leg differ by more than 0.001 ft. In these few cases the reading was repeated still another time. For a 4000-ft traverse of 20 bench marks, the cumulative error should be of the order of 0.004 ft; and a sampling of closure errors indicates that this level of accuracy was maintained. Even though this high level of accuracy on the leveling data is maintained, it still represents a sizable fraction of the uplift resulting from a single injection, which is of the order of 0.01 ft. This problem is inherent in the technique and could have been overcome only by increasing the accuracy of the measurements by an order of magnitude, which would probably have increased the cost by an equivalent amount. In the analysis of the results given below, some of these difficulties are avoided by considering the uplifts resulting from a group of injections rather than a single one.

ANALYSIS OF UPLIFT DATA

The data obtained from the repeated levelings of the bench mark network during the seven experimental injections were analyzed in two different ways. In the first analysis, an effort was made to carry out all the calculations as rigorously as possible without making assumptions as to the general character of the uplift. The calculations were performed on the adjusted closed traverses by assuming that point 3-E, some 3500 ft east of the injection well, was undisturbed by the injections and remained stable throughout the entire period. The elevation of the center point of the network, X, relative to point 3-E can then be established from those line B traverses which were extended out to point 3-E. Since point X is included in each of the other three radial legs of the net, the elevation of all points can be determined.

The profiles of surface uplift calculated in this way are shown in Figs. 11.2 and 11.3. A number of conclusions can be drawn from the examination of these two figures:

1. Apparently there was an error in the original (zero establishing) survey of February 2–12, 1964, involving points C-7 and -8 and most of line D. Although this error (estimated at no more than 0.01 ft) *will persist throughout*, its relative effect will diminish as the total uplift increases.

2. The end points (farthest from center) of all the legs of the net show a net uplift of 0.01 to 0.02 ft. Although this was expected at point D-7, the end points of the other three lines should not have been disturbed. Furthermore, the general shape of the profiles suggests that the uplift of the end points is not real.

3. The total volume of surface uplift estimated by integrating the empirical equation of the profile curve,

$$w = 0.073 \exp\left(\frac{-x^2}{0.71 \times 10^6}\right) ,$$

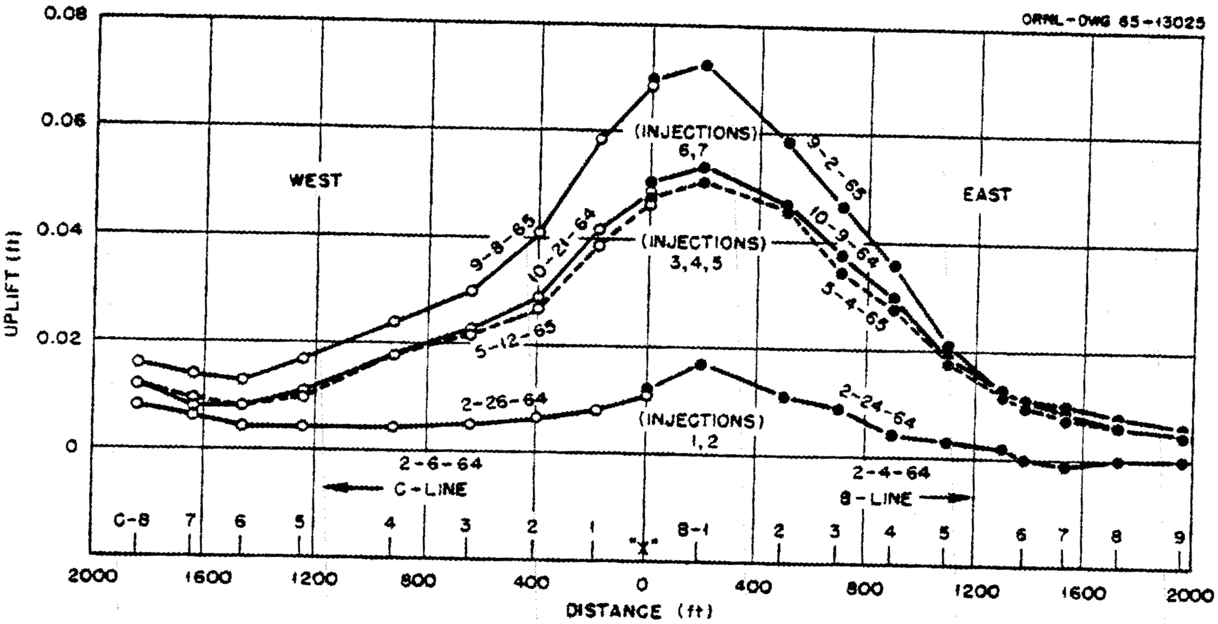

Fig. 11.2. Profile of Surface Uplift, East-West Section.

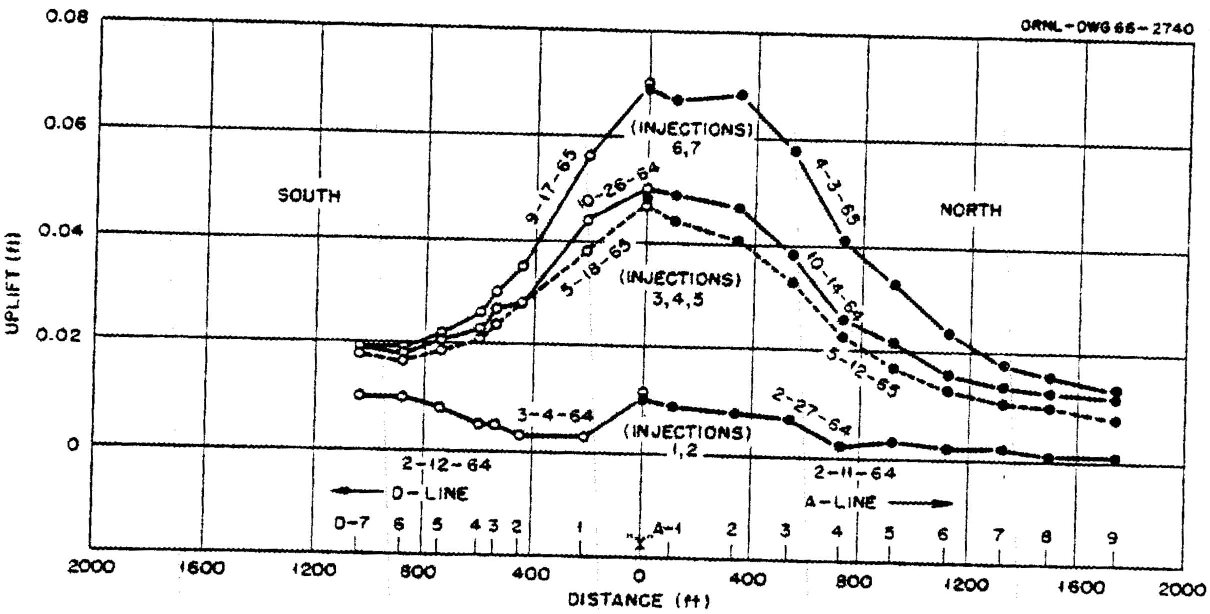

Fig. 11.3. Profile of Surface Uplift, North-South Section.

where

w = surface uplift (ft),

x = radial distance from center (ft),

0.073 = maximum uplift at center,

gives 1.22×10^6 gal, compared with an injected volume of only 0.652×10^6 gal.

These last two observations suggest that some kind of systematic error occurred in either the surveys or the assumptions. For instance, the excessive uplift could be accounted for by a gradual settlement of the base point 3-E during the period.

In the second analysis an attempt was made to obtain a more realistic picture of the uplift by making internal adjustments. In this case, it was assumed that points A-9, B-9, and C-8 were stable and were unaffected by the injections. For each set of traverses, this gave three different elevations for the center point X. A mean of these three elevations was then considered to be the true elevation, and the three individual leg traverses were then "tipped" so that the end points remained undisturbed. The uplift profiles produced by this procedure are shown in Figs. 11.4 and 11.5. Note that point D-7 is still shown uplifted slightly, as expected.

The total volume of surface uplift in this case is 0.80×10^6 gal, calculated from

$$W = 0.062 \exp\left(\frac{-x^2}{0.55 \times 10^6}\right) ,$$

which agrees much more closely with the injected volume of 0.652×10^6 gal. Also, the uplift profiles look much more reasonable and probably more closely represent the actual uplift.

In both analyses of the uplift data, only the surveys taken after injections 2, 5, and 7 were analyzed. Partial data are available for each injection in case the need for that amount of detail should arise.

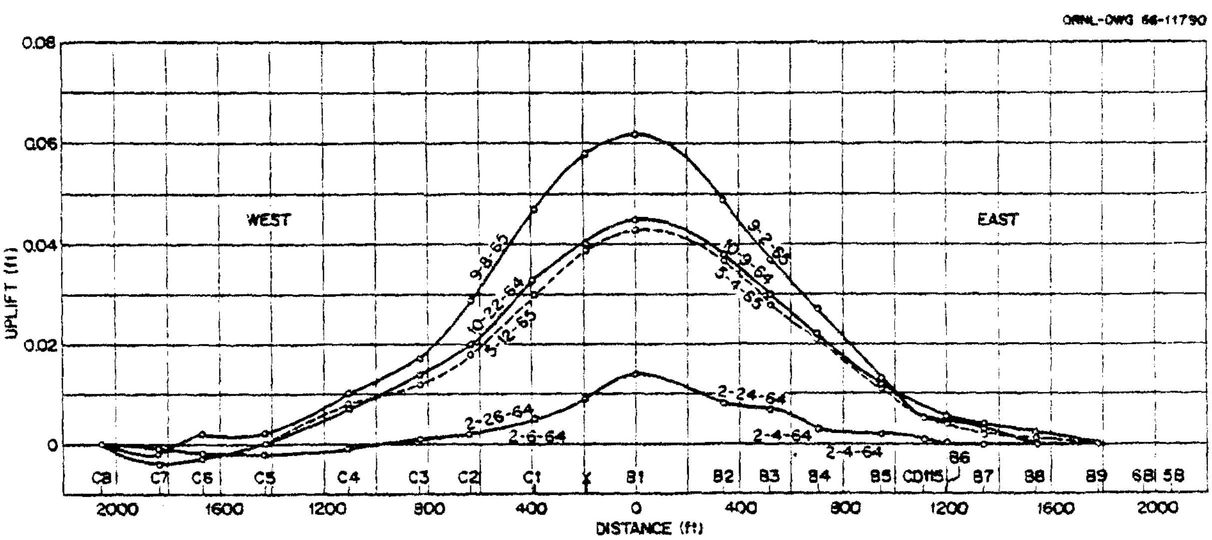

Fig. 11.4. Profile of Surface Uplift, East-West Section.

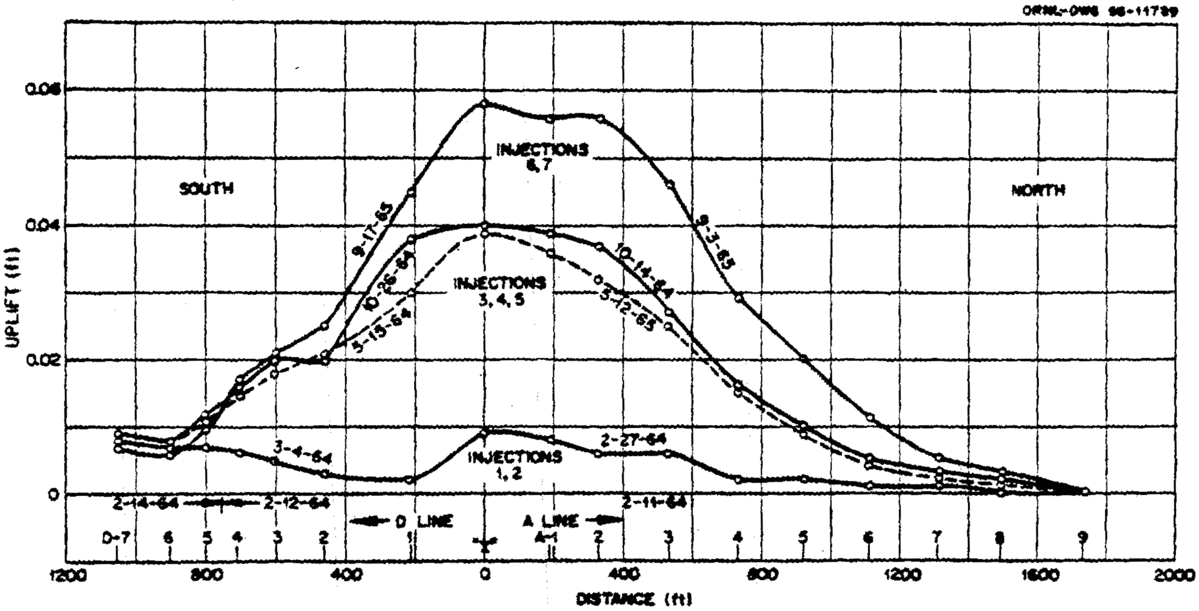

Fig. 11.5. Profile of Surface Uplift, North-South Section.

THEORETICAL DERIVATION OF SURFACE UPLIFT

The surface leveling measurements indicate that each injection caused the ground surface to be uplifted approximately 0.01 ft. This is somewhat less than the estimated thickness of the injection and suggests that the movement of the rock around and over the injections could be considered to be inversely analogous to the subsidence movements which occur over extractive mining operations. If this analogy is valid, the movements and deformations induced by the injected grout sheets are subject to analysis using concepts and techniques borrowed from the highly developed discipline of mining subsidence engineering.

An elastic analysis of mining subsidence by Salamon[2] is particularly applicable to hydraulic fracturing because any algebraically expressible input geometry can be used, equations are available for a number of different physical models of the rock having different deformational characteristics, and a solution can be obtained for any point in the rock system.

The geometrical arrangement of Salamon's analysis is shown in Fig. 11.6. The equations defining the displacement of any point P in the rock are:

$$w = \frac{1}{\pi} \iint_A I_z(\xi,\eta)\, f_1(r^2, z, H)\, d\xi\, d\eta \,, \tag{2}$$

[2]M. G. D. Salamon, "Elastic Analysis of Displacements and Stresses Induced by Mining of Seam of Reef Deposits," *J. S. African Inst. Mining Met.*, pt. I: 64–4, 128–49 (November 1963); pt. II: 64–6, 197–218 (January 1964); pt. III: 64–10, 468–500 (May 1964).

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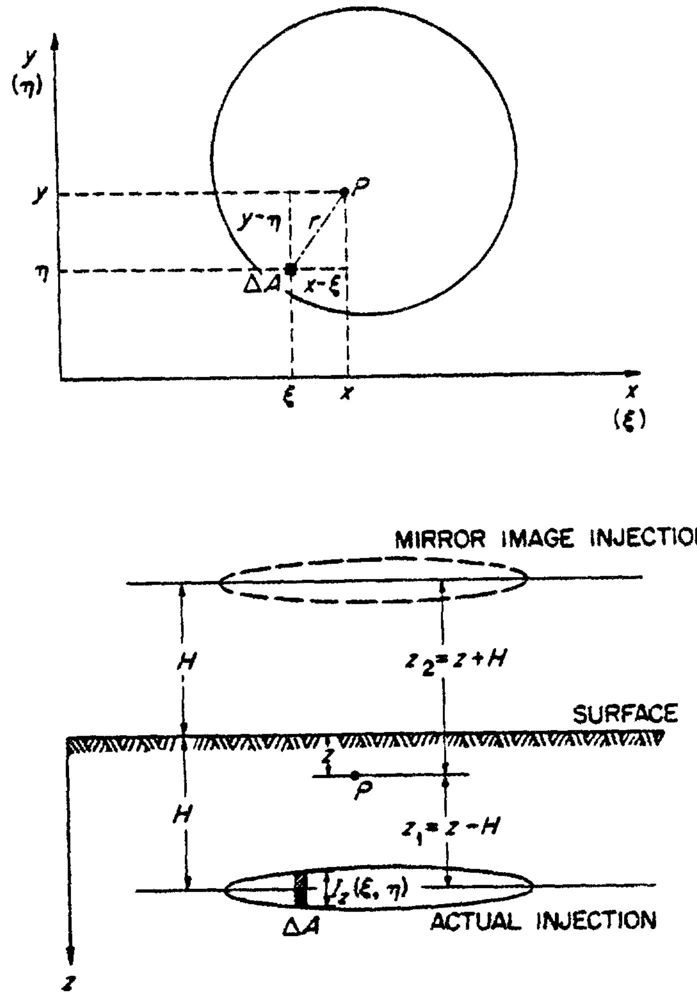

Fig. 11.6. Notation and Geometrical Arrangement of Mirror Image Method.

$$u = \frac{1}{\pi} \iint_A I_z(\xi,\eta)\,(z - \xi)\, f_2(r^2, z, H)\, d\xi\, d\eta\ , \tag{3}$$

$$v = \frac{1}{\pi} \iint_A I_z(\xi,\eta)\,(y - \eta)\, f_2(r^2, z, H)\, d\xi\, d\eta\ , \tag{4}$$

where

$$r^2 = (x - \xi)^2 + (y - \eta)^2 \tag{5}$$

and w, u, v = displacements of point P in the z, x, and y directions respectively,

$I_z(\xi,\ \eta)$ = thickness of the injected grout sheet at any place,

$\iint_A$ = integration over the entire area of the grout sheet,

$f(r^2,\ z,\ H)$ = function describing the deformational properties of the various models simulating the rock,

H = depth of injection,

z, x, y, ξ, η = coordinates as defined by Fig. 11.6.

The functions $f(r^2, z, H)$ for different idealized physical models are given below.

Homogeneous Isotropic Model

The function $f(r^2, z, H)$ that describes the deformational properties of this model is obtained by superimposing the solutions for two injections in an infinite medium so that the condition of a stress-free surface is satisfied (see Fig. 11.6). The superposition is made according to

$$f = F_a + F_m + F_s , \tag{6}$$

where F_a, F_m, and F_s are the functional components arising from the actual injection, the mirror image iniection, and a normal stress, respectively. Components F_a and F_m can be obtained from

$$F_{1i} = \frac{z_i}{8(1-\nu)} \frac{2(2-\nu)z_i^2 + (1-2\nu)r^2}{(r^2 + z_i^2)^{5/2}} \tag{7}$$

$$F_{2i} = \frac{z}{8(1-\nu)} \frac{2(1+\nu)z_i^2 - (1-2\nu)r^2}{(r^2 + z_i^2)^{5/2}} \tag{8}$$

by replacing z_i with z_1 in the actual case and with z_2 in the mirror image case, using

$$z_1 = z - H, \quad z_2 = z + H .$$

The f_s portion is given by

$$F_{1s} = \frac{1}{4(1-\nu)} \left\{ \frac{2(1-\nu)z_2}{(r^2 + z_2^2)^{3/2}} + [z + 2H(1-\nu)] \frac{2z_2^2 - r^2}{(r^2 + z_2^2)^{5/2}} + 3Hzz_2 \frac{2z_2 - 3r^2}{(r^2 + z_2^2)^{7/2}} \right\}, \tag{9}$$

$$F_{2s} = \left[\frac{z}{4(1-\nu)} \frac{1-2\nu}{(r^2 + z_2^2)^{3/2}} - \frac{3z_2(z_1 + 2\nu H)}{(r^2 + z_2^2)^{5/2}} + \frac{3Hz(4z_2^2 - r^2)}{(r^2 + z_2^2)^{7/2}} \right], \tag{10}$$

where ν is Poisson's ratio for the material, the only physical property required.

Frictionless Laminated Model

This model, which can be visualized as a stack of elastic plates separated by frictionless partings, has been suggested as more nearly representing the strongly laminated shale and similar strata in a coal-producing sequence. Since the surface is automatically shear stress free, the mirror image principle can be used for the elimination of the normal stress according to

$$F = F_a - F_m , \tag{11}$$

where F_a and F_m are given by

$$F_1 = -\frac{1}{8\lambda z_i} e^{(-r^2/4\lambda z_i)} \tag{12}$$

and z_1 and z_2 are given by Eq. (8). The physical property parameter λ is defined as

$$\lambda = \frac{h}{2\sqrt{3(1-\nu^2)}}, \tag{13}$$

where h is the mean lamination thickness. This model is not sufficiently rigorous to allow the derivation of horizontal components of displacement.

Similar equations have been derived for a homogeneous transversely isotropic model, which has different properties in the vertical and horizontal directions, and a multimembrane model, which is made up of a large number of completely flexible membranes separated by elastic springs.[2] The expression of the deformational properties of these models is very complex algebraically and will not be given since they were not used in the analysis.

Components of strain can be derived for the homogeneous isotropic model by differentiating Eqs. (1), (2), and (3) according to

$$\epsilon_x = \frac{\partial u}{\partial x},\ \epsilon_y = \frac{\partial v}{\partial y},\ \epsilon_z = \frac{\partial w}{\partial z},\ \gamma_{xy} = \frac{\partial u}{\partial y} + \frac{\partial v}{\partial x},\ \gamma_{xz} = \frac{\partial u}{\partial z} + \frac{\partial w}{\partial x},\ \gamma_{yz} = \frac{\partial v}{\partial z} + \frac{\partial w}{\partial y}, \tag{14}$$

where γ is shear strain in the subscript-indicated plane. The differentiations of Eq. (14) can be performed either before or after the integration indicated in Eqs. (1), (2), and (3). Since a computerized numerical integration was employed in this analysis, the differentiation was carried out first, in which case only the functions describing the model properties require differentiation.

Results of Calculations

A few trial calculations were made on various cross-sectional shapes of circular injections (disk, truncated cone, normal error curve) which indicated that a very flattened circular ellipsoid yielded the most satisfactory displacement distribution. It was also shown that the vertical movements calculated from the homogeneous isotropic model and the frictionless laminated model were nearly identical. Therefore, in all calculations, an elliptical cross section was used in the shape function. The frictionless laminated model was used when only vertical movements were desired, and the homogeneous isotropic model was used when horizontal movements were required for strain calculations.

The calculations were performed on a large digital computer using the Gauss method for numerical double integration. For a circular ellipsoid, the shape function can be written

$$l_z(\xi,\eta) = \frac{a}{c}(c^2 - \xi^2 - n^2)^{1/2}, \tag{15}$$

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where a is the thickness of the very flattened circular ellipsoid measured at the center (i.e., twice the semiminor axis) and c is the radius of the circular ellipsoid (i.e., semimajor axis). Substituting Eq. (15) into Eq. (2) and defining the limits yields the equation on which the integration was performed for the vertical movement,

$$w = \frac{a}{c\pi} \int_{-c}^{c} \int_{-(c^2-\xi^2)^{1/2}}^{(c^2-\xi^2)^{1/2}} (c^2 - \xi^2 - \eta^2)^{1/2} f_1(r^2, z, H)\, d\xi\, d\eta \,, \tag{16}$$

where $f_1(r^2, z, H)$ is obtained from Eqs. (5), (6), (8), and (9) for the homogeneous isotropic model or Eqs. (4), (11), and (12) for the frictionless laminated model. Since a large number of cases were examined and the equations become somewhat involved, Eq. (16) and its derivation are given as an example, and no other expressions of the actual functions to be integrated will be quoted.

Figure 11.7 shows the radial (horizontal) and vertical displacements obtained by this method using a circular ellipsoidal-shaped injection of radius 700 ft at a depth of 1000 ft in a homogeneous isotropic material ($\nu = 0.25$). All displacements are proportional to the center thickness of the injected grout sheet, a, and therefore the displacements are plotted in terms of a. A number of significant points concerning the behavior of the rock mass are apparent from this figure:

1. The defomation below the injected grout sheet is slightly less than, but nearly equal to, that above. The slight difference between upward and downward deformations, caused by the presence of the free surface, results in the center line of the injection being slightly above the original plane of the injection.

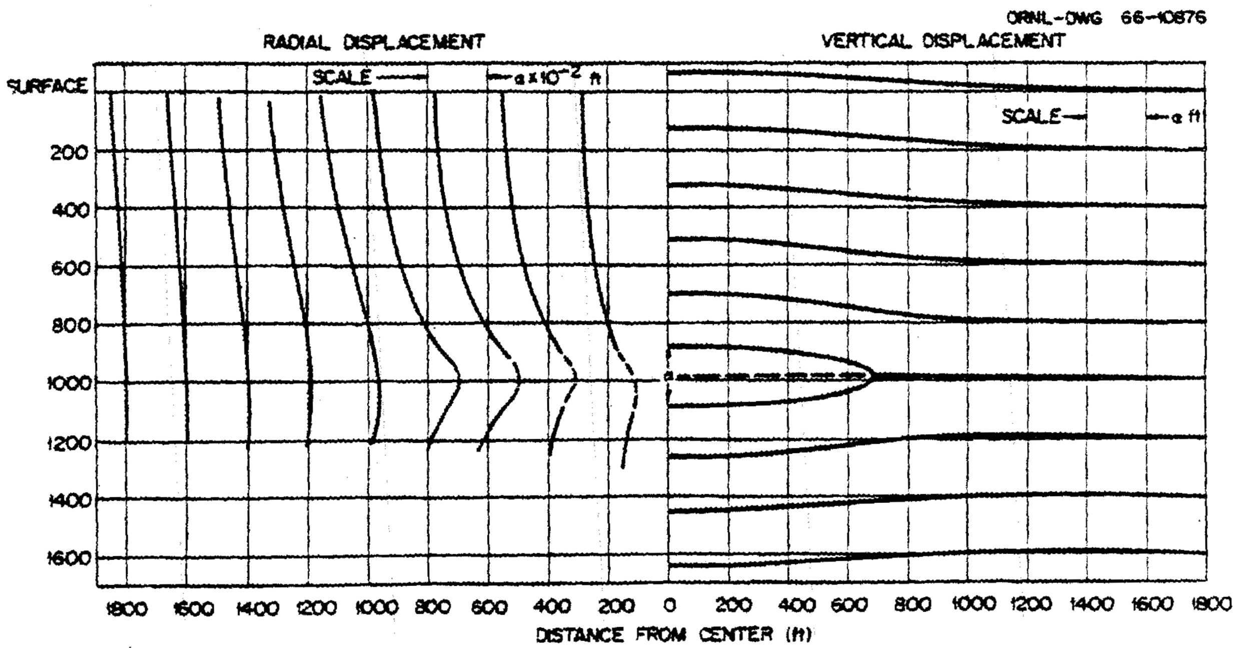

Fig. 11.7. Vertical and Radial Displacement Around a Circular Ellipsoidal Injection.

2. The maximum surface uplift is smaller than the center thickness of the injection (in this case about $\frac{1}{4}$), but the surface uplift extends over a much greater area than the injection.
3. Radial movements are appreciably smaller than vertical movements (in this case approximately $\frac{1}{100}$).
4. The first two points are special cases of a much more important conclusion, which states that the net volume of uplift at any plane above the grout sheet (including the ground surface) is equal to the volume injected and that the net volumetric displacement of any plane below the grout sheet is zero. The downward movement under the grout sheet must be compensated by a lift around the edges (Fig. 11.7), and the reduced surface uplift over the center of the grout sheet is made up by the uplift being spread over a larger area. These relationships can be shown to be theoretically valid regardless of the properties of the rock.

Radial and vertical strain contours for the homogeneous isotropic model (c = 500 ft) are shown in Fig. 11.8. This figure is essentially the differential of the previous one. Again the value of strain is given in terms of the center thickness of the injected grout sheet, α. For example, if $\alpha = 1.0$ ft the values of strain are 10^{-6} ft. This figure illustrates primarily the regions of compressive and tensile strains and the very high strain (stress) concentrations at the tip of the injection.

The manner in which the vertical displacements decrease in amplitude and increase in areal extent upward from the injection suggests the reason for the difficulty in trying to establish the outline of the grout sheet underground based on surface uplift measurements. This is il-

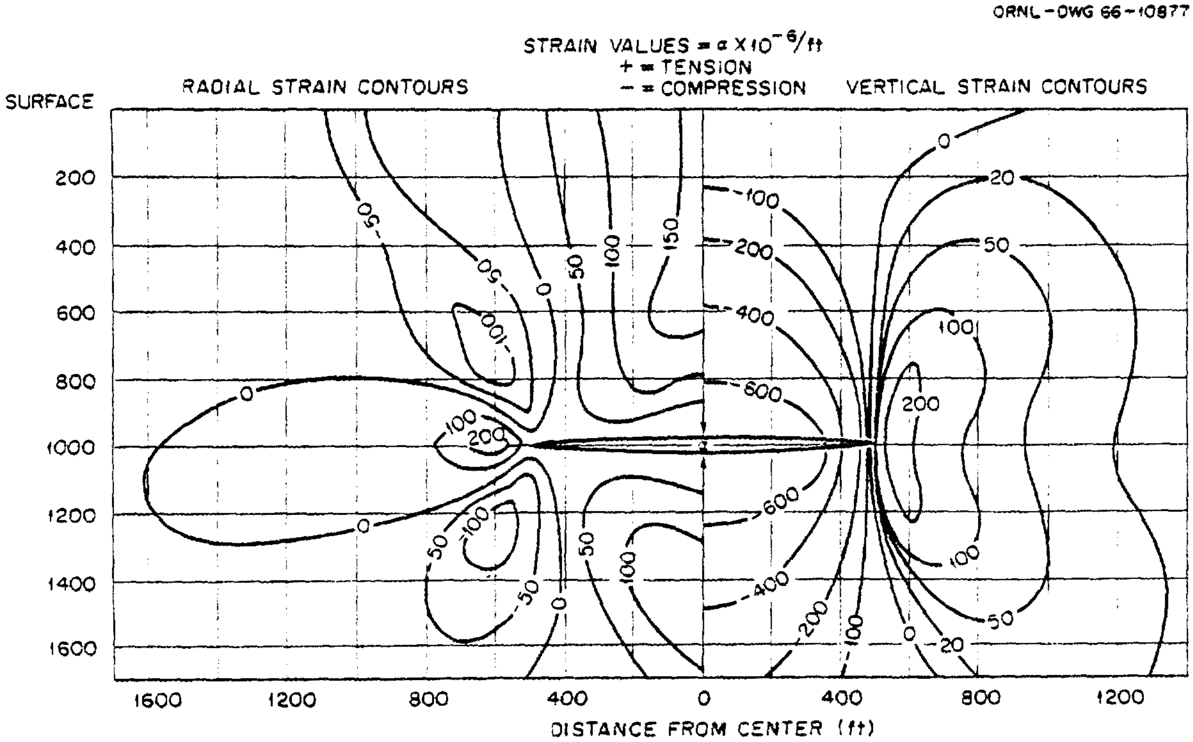

Fig. 11.8. Vertical and Radial Strain Around a Circular Ellipsoidal Injection.

lustrated in Fig. 11.9*a*, where the ratio of maximum surface uplift (a_s) to injection thickness (a_I) is plotted against the ratio of radius of injection to depth (c/H). This shows that at a depth of 1000 ft the maximum surface uplift to be expected ranges from 8% of the injection thickness with a 300-ft radius ($c/H = 0.3$) to 50% of the thickness with a 1000-ft radius ($c/H = 1.0$). When it is realized that the thickness of a single injection is probably of the order of 0.01 ft, it is obvious that extreme accuracy of surface leveling is required. The insensitivity of the surface uplift to changes in shape of the injection is further illustrated in Fig. 11.9*b*, where the eccentricity of the surface uplift contours is plotted against the eccentricity of a completely ellipsoidal grout sheet (i.e., elliptical in plan and section). The figure shows that a high

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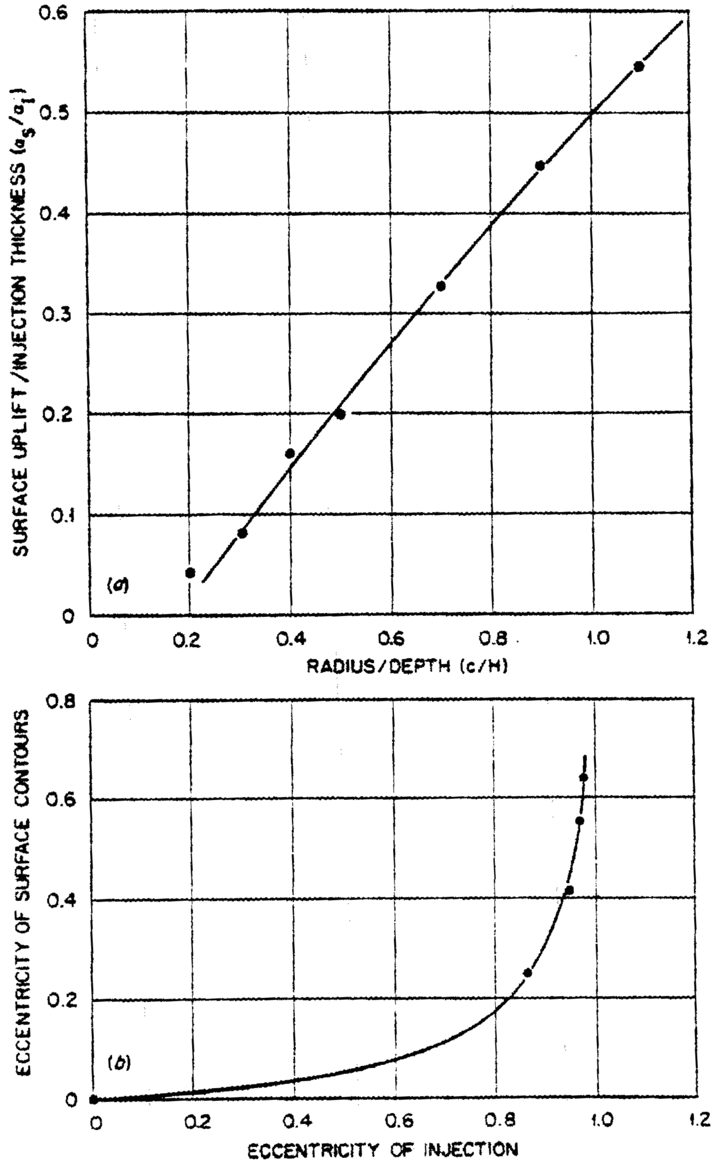

Fig. 11.9. Relationship Between Shape of Injected Grout Sheet and Shape of Surface Uplift.

horizontal eccentricity ($e = 0.8$ to 1.0) is required in the grout sheet before the surface uplift contours depart appreciably from circular ($e = 0$). The eccentricity (e) is defined as

$$e = \frac{\sqrt{a^2 - b^2}}{a} , \tag{17}$$

where a and b are the semiaxes.

The behavior of the surface during the injection process was examined theoretically by assuming a constant pumping rate (224 gpm) and an arbitrary proportionality between the center thickness (α) and the radius of the injection (c),

$$\alpha = c/7000 .$$

As can be seen in Fig. 11.10, the elevation of *all* points on the surface increases linearly with time under these conditions. In the actual case, an exact proportionality between the thickness and the radius of the injection would not be expected throughout the course of an injection.

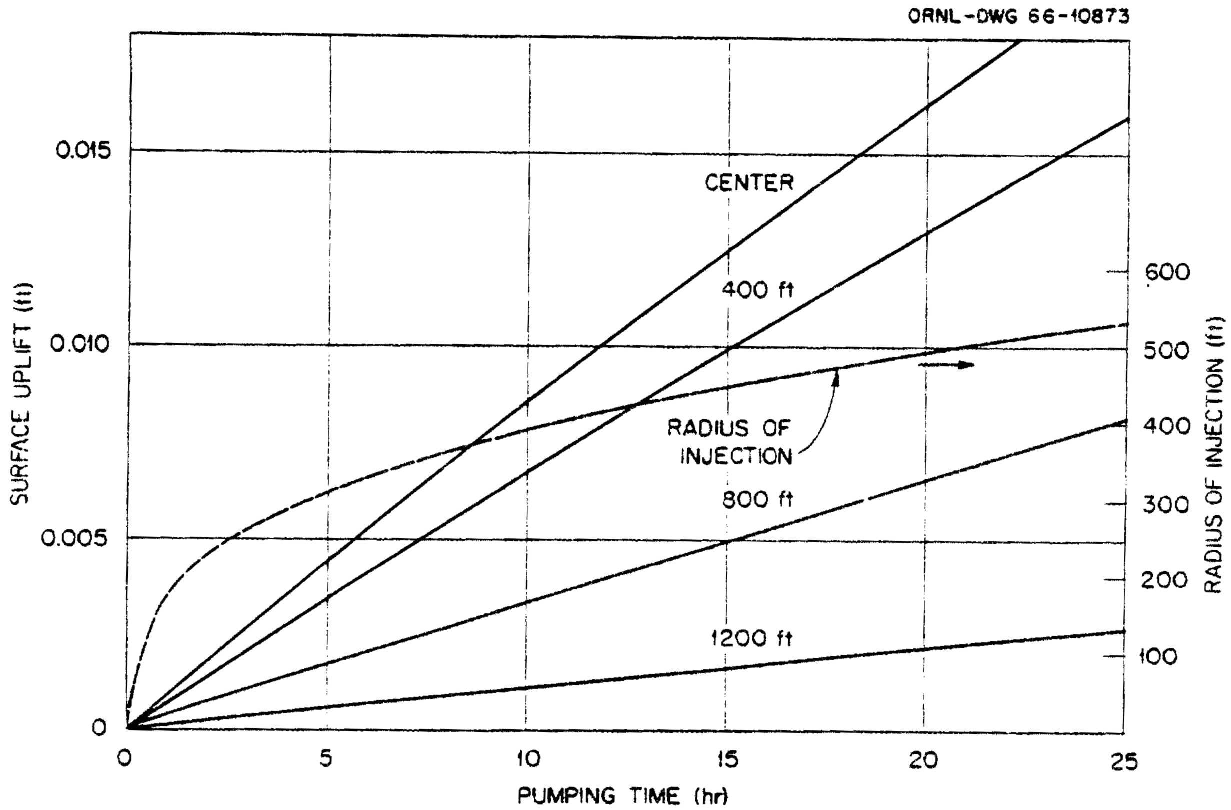

Fig. 11.10. Surface Response Due to a Constant Rate of Water Injection.

CONCLUSIONS

The comparison of analytical results with the meager experimental evidence available tends to support the validity of the inverse subsidence analog assumption and the applicability of Salamon's elastic solution. The main point of departure of the experimental data from that anticipated from the theory is in the volume of the surface uplift. The principal points of agreement are as follows:

1. Vertical movements in the rock overlying the injected grout sheet will decrease in magnitude with distance from the injection. At the surface, approximately 1000 ft above the injection, the uplift will be bell shaped, nearly circular in plan with a normal-error-curve-shaped profile. The surface uplift 2000 ft from the center will be 1 to 5% of the maximum (center) uplift, depending on the radius of the injection.
2. The surface uplifts are very insensitive to the shape and size of the injected grout sheet and therefore are not suitable for inferring the behavior of the injection.

12. Safety Evaluation

The "system" involved in disposal by hydraulic fracturing includes both the fracturing plant on the surface, which mixes and injects the radioactive slurry, and the underground rocks into which the slurry is pumped. In an assessment of the safety of this disposal method, therefore, it is convenient to treat the problem in two parts. The first part discusses the possible failures in the surface plant, the consequences of such failures, and the engineering safeguards that have been taken to assure that these failures will not result in significant releases of radioactivity to the plant environs. The second part examines the possible mechanisms of failure of the rock in the disposal formation and of the rock cover and, on these bases, estimates the total capacity of the present injection well.

SAFETY ANALYSES OF PLANT AND EQUIPMENT

Rupture of Wellhead

The worst single hazard associated with an injection is the possibility that fittings at the wellhead may break off right at the wellhead, thereby permitting some, or all, of the waste slurry that has been injected into the well to flow back up the well into the wellhead cell with no way of shutting off the flow. Depending on the nature of the break at the wellhead, this flow could be up the tubing string, up the annulus between the tubing and the casing, or up both the tubing and the annulus. This hazard will be most severe near the end of an injection, when the volume of waste that has been injected is a maximum. The maximum flow rate back up the well will be determined by the pressure at the bottom of the well and the pressure drop in the well. In this analysis the wellhead injection pressure is assumed to be 1700 psi. The flow up the well, then, is that flow required to produce a pressure drop of 1700 psi. The slurry is a non-Newtonian fluid with n' and K' factors of 0.84 and 0.0099 respectively.[1] The calculated pressure drop of this fluid at various fluid rates in both the annulus and the tubing is shown in Fig. 12.1. From this curve the maximum flow in the tubing is found to be 530 gpm, and the maximum flow in the annulus is found to be 995 gpm; the combined flow would be 1525 gpm. The actual flow rate would be less, because these calculations take no account of friction losses and pressure drop in the fracture.

[1]Halliburton Company, *Chemical Research and Development Report for November, 1962*, C 55–62.

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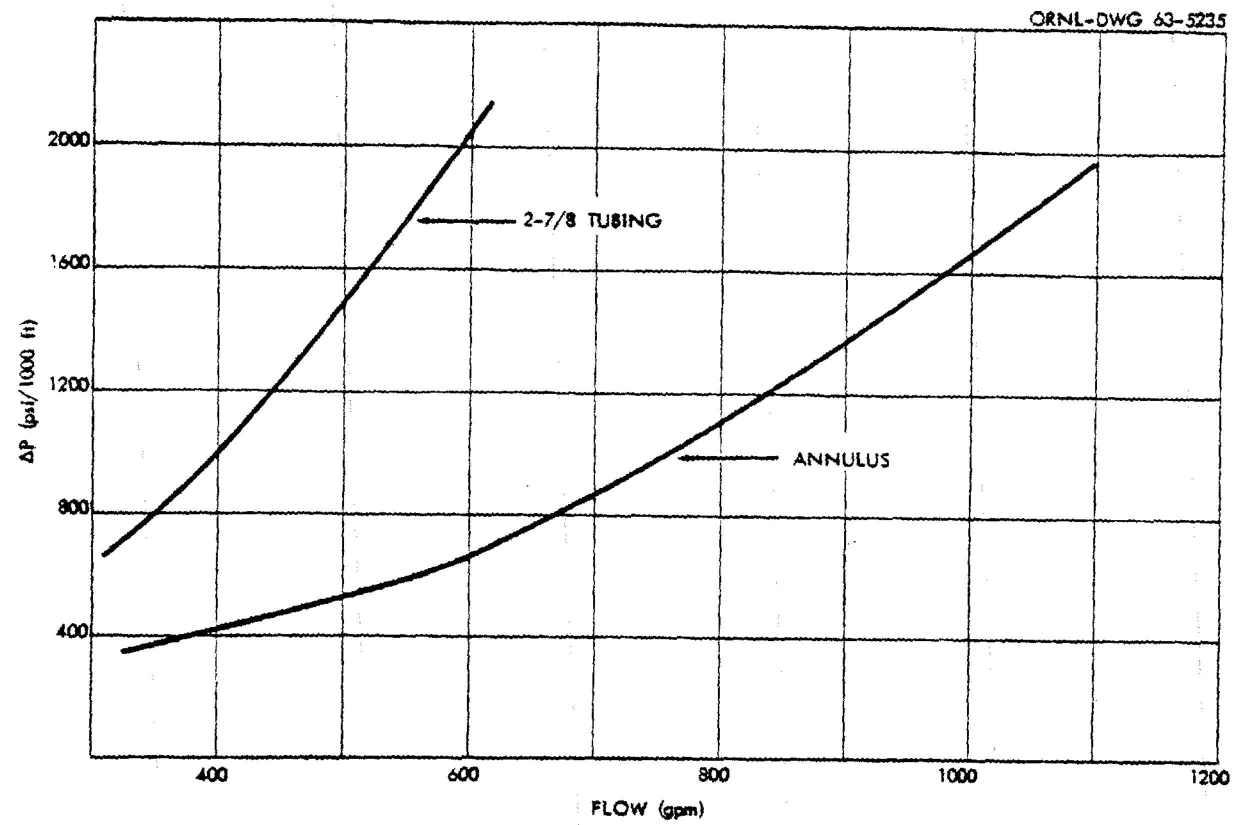

Fig. 12.1. Pressure Drop of Slurry in the Injection Well.

In the event that an accident such as that described above causes the slurry to be discharged into the wellhead cell, an 18-in. drain line has been installed from the floor of the wellhead cell to the nearby emergency waste trench. This line is 130 ft long and drops 22 ft in this distance. The calculated pressure drop in this line, at a flow of 1500 gpm, is approximately 1 psi. Two water lines have been installed in the wellhead cell to assist in washing the slurry down the drain. Once the slurry has been washed into the waste trench, it can be allowed to set there and be covered over at leisure.

Break in Process Line

The type of hazard that will result from a break in a process line depends on the location of the line, on whether it is in high-pressure or low-pressure service, and on the fluid carried by the line.

The low-pressure process lines that carry radioactive waste solution have been installed either underground or in enclosed pits or cells. A break in one of the underground lines would result in the loss of some quantity of waste solution to the ground, but this is a hazard shared with other waste transfer lines, and it seems no more serious here. A break in one of the low-pressure process lines inside a cell or pit would result in the discharge of a considerable quantity of radioactive fluid over equipment, piping, and anything else in the vicinity. The valve pit and process cells are so constructed that there is no direct path for the escape of any fluid discharged into a cell; any material so discharged can be contained and cleaned up at leisure. Operating procedures require that all operators be outside the cells and the cell hatches be closed while waste solution is being pumped; hence the hazard likely to result from a broken line inside a cell is small.

A rupture of a high-pressure line inside a process cell would, as was the case for the low-pressure lines, result in the spraying of slurry inside the cell until a pump was shut off or a valve closed. This hazard seems no more serious than was the case for the low-pressure lines. In this case, however, there is the additional hazard that a rupture might occur suddenly enough so that a fragment of high-pressure pipe would be given sufficient energy to penetrate a wall, a window, or the roof of a cell, and thereby release contamination outside the cells. To guard against this hazard the windows in the pump cell and the wellhead (the only cells to contain high-pressure lines) are made of bullet-proof glass, and the roof grating is covered with $\frac{1}{4}$-in. steel plate. The largest unrestrained piece of equipment that seems likely to become a missile is a fragment of the plug container, which is on the top of the wellhead assembly. A sudden fracture of this piece of equipment could propel a mass of perhaps 50 lb against the hatch of the wellhead cell. A calculation of the maximum probable impact force of this fragment gives a value (22,500 lb) well below the yield strength of the roof structure (about 50,000 lb). The impact force of a similar fragment against the cell wall is also far below the force necessary for penetration. The calculation of the maximum probable kinetic energy of a small metal fragment directly against the $\frac{1}{4}$-in. roof plate gives a value of 114 ft-lb/in.; literature values indicate that at least 1400 ft-lb/in. is required to penetrate a $\frac{1}{4}$-in. plate. It is concluded, therefore, that there is little danger of the cell integrity being breached by a missile.

There are two cases in which process lines extending outside the cells will be subjected to high pressure: (1) the operation of the standby pumping equipment which will pressurize the line between the standby pump and the valve rack in the wellhead cell and (2) the slotting of the casing at the beginning of a run, which has to be done with high-pressure wellhead connections extending through hatches in the roof of the wellhead cell. Neither of these operations involves the use of radioactive materials, but both have the inherent hazard of all high-pressure operations. In this case it is a hazard that is common to similar operations in the petroleum industry and, as such, is a hazard with which the operators are quite familiar.

Spread of Contamination from Slotting Operation

At the conclusion of each slotting operation the tubing string in the injection well must be lifted about 20 ft to position the bottom of the tubing string well above the slot through which the injection will be made. This operation requires the handling and removal of 20 to 30 ft of wet tubing that will be contaminated to some unknown extent. The hazard of direct radiation is negligible in this case; the only real problem is the possible spread of contamination. An estimate of the amount of ^{90}Sr that might be present on a 30-ft length of tubing indicates that the total amount would be about 3×10^{-7} curie. If it is assumed that 10% of this becomes airborne and that 10% of that is inhaled by one person (both assumptions are quite pessimistic) the maximum intake is only 20% of the maximum allowable weekly intake. The hazard of this operation seems slight.

Leak in Waste Transfer Line

This facility shares with the existing waste transfer system the hazard of waste leaking into White Oak Creek from a leak in the waste transfer line that crosses the creek. Safeguards against this hazard include the usual Laboratory procedure of pressurizing the line before each transfer to detect the existence of major leaks and the monitoring of the creek a short distance downstream of the crossing. If it is assumed that a doubling of the background reading on the downstream monitor will be regarded as indicative of a leak, then at an average stream flow of 198×10^6 gal/month and an average background of 1.36×10^{-6} $\mu c/ml$, a leak of as little as 6 ml/min could be detected.

Plugging of Jet Mixer

In grouting operations in the petroleum industry, it is not uncommon for the jet mixer to be plugged by a large piece of caked cement or by some foreign object. In such cases the liquid flow is diverted up the mixer hopper, resulting in considerable splashing and scattering of material. To reduce the hazard of such an occurrence in this operation, the hopper has been enclosed with a metal shield to contain any splashing that may occur, and an overflow line to the surge tank has been provided to increase the allowable time for shutting off the waste pump. Spray nozzles have been installed in the hopper to help in washing the hopper after such a mishap.

Failure of Services

A power failure at the plant site would affect the waste pump, the water pump, the Densometer pump, and the lights. Failure of these items would force a halt in the injection but would not cause a serious hazard, since the injection pump and the standby pump are not dependent on outside power and would not be affected. If the power failure were temporary, the wellhead could be valved off and the injection pump shut down until pumping could be resumed. Alternatively, if the power were likely to be off for a considerable time, the injection could be terminated. Water from the storage tank would be used to feed the standby injection pump, which would force the slurry in the well down into the fracture; the well would be sealed off, and the equipment would be washed.

Failure of one air compressor would not be serious, since a spare compressor is always provided. Failure of both compressors would force a halt in the injection but would not cause serious difficulties; the injection could be terminated, if necessary, in the same fashion as after a power failure.

The water supply will be used for washing equipment and as a feed for the standby injection pump. Water for these functions can be supplied from several sources – a 25,000-gal storage tank, the waste pit, a 2-in. water line supplying the area, and tank trucks – and the failure of all these sources is extremely unlikely.

Airborne Activity from Waste Tank Sparging

Several days before an injection takes place, each of the waste storage tanks is agitated by air sparging and then sampled. The air flow rate required for sparging is 16 cfm in two of the waste tanks and 8 cfm in the third. Data on aerosols formed by vigorous mixing of solutions and air indicate that the particulate concentration formed by sparging will be of the order of 10 to 15 mg/m^3 originally and about 10 mg/m^3 after several changes of direction of the air stream. The particle size distribution will contain equal weight fractions of particles in the range of less than 0.4 μ, 0.4 to 1.3 μ, 1.3 to 3 μ, 3 to 5 μ, and greater than 5 μ.[2] The filter efficiency is assumed to be 99.97% for particles larger than 0.3 μ, 95% for particles between 0.3 and 0.1 μ, and nil for particles smaller than 0.1 μ. These assumptions of filter efficiency, particle size distribution, and particle concentration can be used to calculate a particle concentration in the filtered air of 0.89 mg/m^3. The assumed waste activity is 0.015 curie/gal. The product of this waste activity and the particulate concentration gives a figure for the airborne contamination leaving the filter of 3.4×10^{-9} $\mu c/ml$. For a waste of the assumed composition, this is equivalent to 1.9×10^{-10} $\mu c/ml$ of ^{90}Sr (63% of the MPC_a for occupational workers for a 40-hr week), 2.98×10^{-9} $\mu c/ml$ of ^{137}Cs (5% of MPC_a), and 1.67×10^{-10} $\mu c/ml$ of ^{106}Ru (0.21% of MPC_a). Since there will be further dilution from the vent and since the exposure time is not likely to exceed 8 hr/month, the waste tank filter system is deemed adequate.

Radiation Exposures

The specific activity of the ORNL intermediate-level waste solution is so low that external radiation exposure is not a serious hazard; the protection installed for containment is more than adequate for shielding protection also. Dose rates have been calculated for three cases that are of particular interest: 5 ft from the surge tank with 12 in. of concrete shielding, on top of the surge tank with no shielding, and above the valve pit with no shielding. The respective doses were 0.36, 28, and 41.4 mr/hr.

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[2] A. R. Irvine and J. P. Nichols, *Hazards Report for Building 2527*, CF-60-5-22, 40 pp.

Conclusions

Most of the hazards associated with the fracturing plant are hazards that are common to any process that handles waste solution, for example, a leaking transfer or process line and airborne contamination. As such, these hazards do not seem very serious, particularly since the specific activity of the waste solution is so low. The remaining hazards are those that are inherent in dealing with high-pressure equipment. Here the hazard has been minimized, where feasible, by installing the equipment in cells where leakage or fragments of ruptured equipment can be contained. There remains the hazard that some operations with high-pressure equipment must be performed outside the cells. These operations are routine to the petroleum industry, the equipment is pressure tested before the operations are performed, the operations are of short duration, and no radioactive solutions will be involved. Nonetheless some small but immeasurable hazard exists. (Recalculation of the above in light of modifications to the plant, new procedures used, and the higher activity of the waste concentrate in the ILW injections does not materially change these conclusions.)

SAFETY ANALYSES OF ROCK FAILURES

It was realized from the beginning that the behavior of the shale near the injected grout sheets and of the rocks making up the rest of the system would exercise a controlling influence on the ultimate capacity of the disposal well. The rocks overlying the injections provide both shielding and an isolation barrier, the integrity of which must be maintained if the method is to be successful. Each successive injection disturbs these overlying rocks, as was seen by the measured uplift of the surface directly over the seven experimental injections. Obviously, it is not possible to continue to inject grout sheets, one on top of another indefinitely, with each injection adding an increment of rock deformation and surface uplift. Eventually the rocks must fail, and continued injection could result in the outflow of the waste slurry on the surface or the opening of fissures in the rocks, leading to leaching of the grout by circulating groundwater.

Failure Mechanisms

Based on an understanding of the various parts of the system, it was possible to postulate a number of failure mechanisms. These are listed and discussed below in order of decreasing probability or importance. Some of the lower ranked ones, although having a small probability, are still possible and are included primarily to broaden the understanding of the associated rock mechanics.

1. Failure by the formation of a vertical instead of a horizontal fracture. Since this mechanism is considered the most probable, it will be analyzed and discussed in detail.

2. Failure by a large increase in the permeability of the shale. The upward-directed displacements over and around the injection could cause an opening of pore spaces and permeability channels in the shale. This might permit groundwater to percolate to the injection depth. The rock cover wells installed at the site were designed so that the permeability of the shale at the 550- to 650-ft depth level could be measured periodically. This can be accomplished simply by measuring the rate at which water under relatively low but constant pressure flows into the strata. Any large increase in this acceptance rate following a group of injections would indicate that the permeability of the cover rock had been affected.
3. Failure by shear fracture along a conical surface. A sufficiently large number of nearly identically sized injections may be capable of inducing a shear stress in excess of the strength of the rocks so that an inverted cone-shaped mass of material would be "punched" up out of the ground. Stress analysis indicates that the shear stresses die out very rapidly upward and outward from the edge of the injection but that they are high near the tip. This would suggest that whereas such a failure may be initiated at the tip of the fracture, it would not extend far enough to cause a failure.
4. Failure of the cement bonding a well casing into the hole. A failure of this type may be more probable than is indicated by its position in this list because of the large number of observation and monitoring wells which have been drilled and cased through the injection depth. It was placed here because (1) the failure is primarily a function of the quality of the cement and the care in its placement, (2) the failure would be localized at the site of the well and any release would probably be small, and (3) it may be possible to repair the damage by suitable operations at the well. For these reasons, a failure of this type is not considered serious and probably would not force termination of operations.
5. Failure of the rock around cased holes due to pinning effect. The several holes cased and cemented through the injection level effectively pin the strata above and below the injection together. The restraint imposed on the rocks around the well in this manner could give rise to a failure of the rock. This situation is extremely difficult to analyze, but a failure does not seem probable for the following reasons: After the first few injections have intersected the well, a vertical compressive stress is induced in the rock around the well. This stress would tend to restrict later injections approaching the area, either by forcing them to become thinner or by preventing close approach entirely. In either case the net effect is to limit the induced stresses around the well.

Failure by the Formation of a Vertical Fracture

As was indicated in the preceding section, the most probable mechanism by which the rock at the hydraulic fracturing plant may fail is the formation of a vertical fracture. The orientation of a hydraulically induced fracture is controlled mainly by the orientation of the principal stress field in the rock.[3] It will form perpendicular to the least compressive principal stress. Other factors, such as bedding plane weaknesses, stress concentrations around the borehole, and the configuration of the casing perforation, may affect the fracture orientation, especially when the intermediate principal stress has very nearly the same value as the least stress.

In this analysis, the original state of stress, the induced stress, and the tensile strengths of the shale will be considered; the other factors will be discussed later. The analysis is based on

[3] M. K. Hubbert and D. G. Willis, "Mechanics of Hydraulic Fracturing," *J. Petrol. Technol., Trans. AIME* 210, 153–66 (1967).

the assumption that a failure condition has been reached when the total stresses at any point in the rock mass are such that there is an equal probability of either a vertical or a horizontal fracture. This situation will occur when the total vertical stress exceeds the minimum total horizontal stress by an amount equal to the difference between the vertical and horizontal tensile strengths.

If this condition could be identified, it would represent the time when use of the disposal well should be discontinued. Substantially larger volumes would have to be injected in order to create a vertical fracture of dangerous dimensions. The vertical component of the primitive stress field is usually taken to be a principal stress and to be due to the weight of the overlying material:

$$S_z = \delta H ,$$

where

S_z = vertical component of original stress,

δ = density factor (usually very close to 1 psi per foot of depth),

H = depth.

The horizontal components of the primitive stress have been measured only in those areas where the rock comes very close to duplicating the behavior of a perfectly elastic solid (i.e., granite or dense homogeneous limestone). Even then the accuracy of the measurement is not good. In other localities the value of the horizontal primitive stresses can only be estimated from elasticity [$S_x = \nu S_z/(1 - \nu)$, where ν = Poisson's ratio], from plasticity ($S_x = S_y = S_z$), or from geologic observations. For example, in the Oak Ridge area, the geological structure is dominated by thrust faulting and folding associated with the Appalachian Revolution. This suggests that large compressive horizontal stresses were once present, and, since there is no normal faulting of a more recent age, they probably still exist but are reduced in magnitude. The development of horizontal hydraulic fractures in the area, indicating that both the horizontal stresses are larger (in compression) than the vertical stress, tends to confirm this conclusion.

Measurement or even estimation of the original state of stress is very difficult. In those few areas in the world where measurements have been made, the maximum horizontal stress has never been found to exceed three times the vertical stress.[4] Since it is the intermediate stress, the lesser of the two horizontal stresses, which controls the fracture orientation, an upper limit of $S_y/S_z = 2.0$ is assumed for the Oak Ridge area. Geological evidence and the fact that horizontal fractures develop suggest that the horizontal stress is not less than the vertical, and therefore a lower limit of $S_y/S_z = 1.0$ is indicated.

The stresses induced in the host rock around an injected grout sheet can be analyzed by a modification of Sneddon's[5] solution for the stress distribution around an elliptical Griffith crack

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[4]E. R. Leeman, "The Measurement of Stress in Rock," *J. S. African Inst. Mining Met.* 65(2), 45–114 and 65(4), 254–84 (1964).

[5]I. N. Sneddon, "The Distribution of Stress in the Neighborhood of a Crack in an Elastic Solid," *Proc. Roy. Soc., Ser. A* 187(1009), 209–60 (Oct. 22, 1946).

in an infinite elastic body. The equations defining these stresses are as follows:

$$
\begin{aligned}
\sigma_z &= \frac{2P_0}{\pi}\,[C_1^0(\rho,\zeta) - C_2^0(\rho,\zeta) - S_1^0(\rho,\zeta)]\,,\\
\tau_{zR} &= \frac{2P_0}{\pi}\,[C_2^1(\rho,\zeta) - S_1^1(\rho,\zeta)]\,,\\
\sigma_R + \sigma_\theta + \sigma_z &= \frac{4(1+\nu)}{\pi}\,P_0\,[C_1^0(\rho,\zeta) - S_0^0(\rho,\zeta)]\,,\\
\sigma_\theta - \sigma_R &= \frac{2P_0}{\pi}\,\{(1-2\nu)[C_1^2(\rho,\zeta) - S_0^2(\rho,\zeta) - \zeta\, C_2^2(\rho,\zeta) - S_1^2(\rho,\zeta)]\}\,,
\end{aligned}
\tag{2}
$$

where

σ_z, σ_R, σ_θ = vertical, radial, and tangential stresses respectively,
τ_{zR} = shear stress,
ν = Poisson's ratio,
P_0 = pressure inside crack,
ρ, ζ = dimensionless coordinates defined as $\rho = r/c$ and $\zeta = z/c$.

Here z, r, θ are cylindrical coordinates of the point at which the stresses are computed taking the center of the crack as the origin, and c is circular radius of crack.

The functional coefficients $C_n^m(\rho,\zeta)$ and $S_n^m(\rho,\zeta)$ are given by

$$
\begin{aligned}
C_1^0 &= R^{-1/2}\cos\frac{1}{2}\Phi\,, & S_1^0 &= R^{-1/2}\sin\frac{1}{2}\Phi\,,\\
C_2^0 &= \lambda R^{-3/2}\cos\left(\frac{3}{2}\Phi - \bar{\omega}\right), & S_2^0 &= \lambda R^{-3/2}\sin\left(\frac{3}{2}\Phi - \bar{\omega}\right),\\
C_0^1 &= \frac{1}{\rho}\left(R^{1/2}\cos\frac{1}{2}\Phi - \zeta\right), & S_0^1 &= \frac{1}{\rho}\left(1 - R^{1/2}\sin\frac{1}{2}\Phi\right),\\
C_1^1 &= \frac{1}{\rho} - \frac{\lambda}{\rho}R^{-1/2}\cos\left(\bar{\omega} - \frac{1}{2}\Phi\right), & S_1^1 &= \frac{\lambda}{\rho}R^{-1/2}\sin\left(\bar{\omega} - \frac{1}{2}\Phi\right),\\
C_2^1 &= \rho R^{-3/2}\cos\frac{3}{2}\Phi\,, & S_2^1 &= \rho R^{-3/2}\sin\frac{3}{2}\Phi\,,\\
C_1^2 &= \frac{2}{\rho}C_0^1 - C_1^0\,, & S_1^2 &= \frac{2}{\rho}S_0^1 - S_1^0\,,\\
C_2^2 &= \frac{2}{\rho}C_1^1 - C_2^0\,, & S_0^2 &= \frac{1}{\rho}(C_0^1 - \zeta S_0^1)\,,\\
S_0^0 &= \tan^{-1}\frac{R^{1/2}\sin\frac{1}{2}\Phi + \lambda\sin\bar{\omega}}{R^{1/2}\cos\frac{1}{2}\Phi + \lambda\cos\bar{\omega}}\,,
\end{aligned}
\tag{3}
$$

where

$$\lambda^2 = 1 + \zeta^2 , \quad \tan \bar{\omega} = 1/\zeta ,$$

$$R^2 = (\rho^2 + \zeta^2 - 1)^2 + 4\zeta^2 , \quad \cot \Phi = \frac{(\rho^2 + \zeta^2 - 1)}{2\zeta} . \tag{4}$$

Since the points which will be of interest are relatively near to the injection, the effect of the free surface can be neglected without introducing appreciable error.

Analysis of these induced stresses indicates that except for a small area near the tip of the injection, the maximum difference between the vertical and horizontal stresses occurs along the line above the center of the grout sheet, that is, coincident with the injection well. Also, along this line the two induced horizontal stresses are equal, and the induced vertical stress is a principal stress. The variation of these stresses in terms of the internal pressure P_0 with distance from the level of the injection is shown by the solid curves in Fig. 12.2. The internal pressure

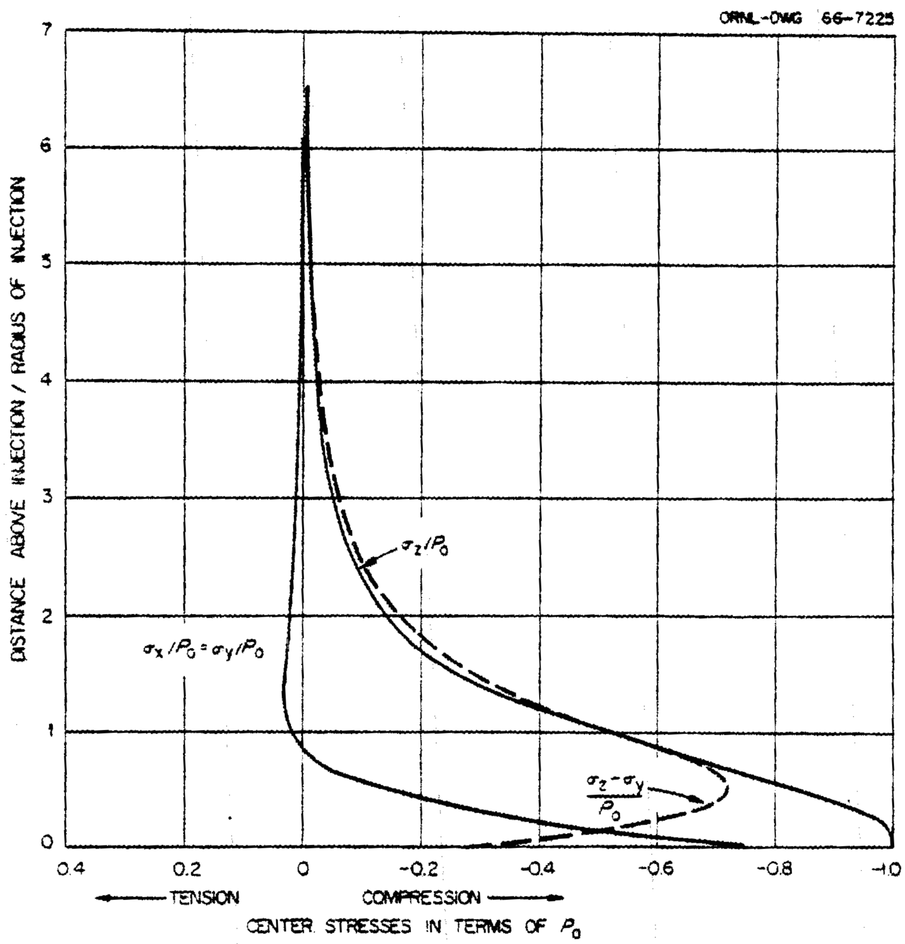

Fig. 12.2. Induced Stresses Above Center of Circular Ellipsoidal Injection.

P_0 in this case is the amount by which the static fluid pressure in the injection exceeds the overburden pressure. For a single injection P_0 is very small. It can be estimated using[5]

$$P_0 = \frac{\pi E \alpha}{8(1 - \nu^2)c}, \tag{5}$$

where

c = horizontal radius of injection,

α = thickness of injection measured at the center,

E = modulus of elasticity,

ν = Poisson's ratio.

For a 40,000-gal injection with $c = 500$ ft and $\alpha = 0.01$ ft and using $E = 10^6$ psi and $\nu = 0.25$ (determined from laboratory tests), this equation gives $P_0 = 8.4$ psi. The effects of each individual injection will be cumulative, however, and it is obvious that after a few score injections a sizable pressure will be built up.

It is the difference between the induced vertical and horizontal stresses ($\sigma_z - \sigma_y$) which determines the influence of the prior injections on the stress field. This difference is plotted as the dashed curve in Fig. 12.2, where it can be seen that the most adverse location is 0.55c (where c = radius of injection) above the center of the injection. This critical point will be the first to satisfy the failure condition, and all of the following analysis is therefore based on its behavior.

Estimated Capacity of Present Injection Well

It is now possible to write the equations defining the sum of the influences in the vertical (Σ_z) and horizontal (Σ_y) directions at any point in the rock mass:

$$\begin{aligned} \Sigma_z &= S_z + \sigma_z - J_z \\ &= S_z + \alpha_z P_0 - J_z , \\ \Sigma_y &= S_y + \sigma_y - J_y \\ &= \beta S_z + \alpha_y P_0 - J_y , \end{aligned} \tag{6}$$

where

α_z, α_y = coefficients of the induced stress from Fig. 12.2 (for the critical point, $\alpha_z = -0.85$, $\alpha_y = -0.10$),

β = ratio of the original horizontal to vertical stresses ($S_y = \beta S_z$),

J_z = tensile strength in z direction, that is, parallel to the bedding,

J_y = tensile strength perpendicular to bedding planes.

When the sums of the influences in the two directions are equal at the critical point, by the previous definition, a failure condition exists. From this, it can be seen that the ratio Σ_y/Σ_z has the significance of an engineering safety factor for the system.

The variation of this safety factor as a function of the total thickness of injections for various radii of injection and various β values is shown in Fig. 12.3. The physical properties of the shale used in the preparation of this figure were: depth = 870 ft, $E = 10^6$ psi, $\alpha = 0.25$, $J_y = 900$ psi, and $J_z = 300$ psi. These values were estimated from laboratory tests of specimens obtained from the plant site. This shale is very variable both vertically and laterally, and the samples were not originally obtained for these tests. Therefore these values for the physical properties can be considered only as estimates.

The maximum ultimate capacity of the present injection well can be estimated from Fig. 12.3. Table 12.1 shows the range of that ultimate capacity.

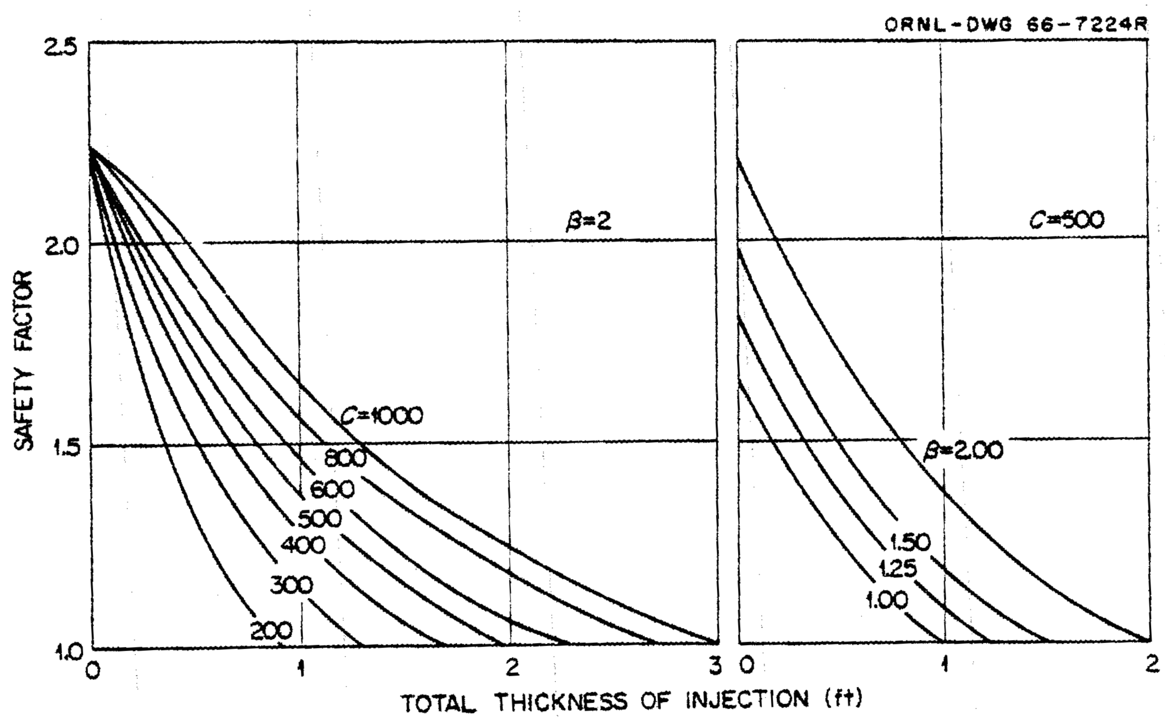

Fig. 12.3. Variation of Safety Factor as a Function of Total Thickness of the Injection, Injection Radius (c), and Original Stress Ratio (β).

Table 12.1. Function of Rupture Radius and Preexisting Rock Stresses

Mean Radius of Injection (ft)	Maximum Safe Capacity (millions of gallons) $\beta = 1.0$	Maximum Safe Capacity (millions of gallons) $\beta = 2.0$
300	0.9	2.0
500	4.1	8.0
700	11.3	20.0
1000	32.8	49.3

Discussion

The induced stress solution is based on the assumption that the material behaves elastically. Laboratory tests indicated that small samples from the shale formation are approximately linearly elastic perpendicular to the bedding planes. Although some transverse anisotropy is undoubtedly present, this should not introduce appreciable error at the relatively small values of stress and strain attained. The validity of the assumption of homogeneity and continuity appears to be supported by the lack of any well-developed jointing or fracturing in the many cores taken from the site. It is questionable whether the shales at the plant site will exhibit sufficient time-dependent properties over the lifetime of a single well to influence the analysis. Any stress relief due to plastic deformation which may occur would tend to increase the capacity of the system. Neglecting this effect is therefore an error on the side of safety.

The analysis is based on the proposition that only the state of stress and the tensile strength of the shale influence the orientation of the fracture. The state of stress immediately adjacent to the borehole is modified by the presence of the hole. In general, this disturbance will increase the horizontal stresses but leave the vertical stress unchanged. This stress concentration effect would tend to favor the formation of horizontal fractures. These stress concentrations die out within three diameters from the borehole, and it has been suggested[6] that a horizontal fracture initiated under the control of these concentrations will revert to its normal, vertical mode a few feet from the well and "back up" to the well. The configuration of the pressurized interval in the well also contributes to the orientation of the fracture, initially at least. When the fracturing is done in an uncased hole with a packed-off interval greater than 1.5 m, the induced stresses favor the formation of a vertical fracture except very near the packers.[5] The sand-jet slotting technique used at the fracturing plant produces a very narrow pressurized interval. This configuration is highly conducive to the initiation of horizontal fractures. The overall influence of this factor depends upon the propensity of a fracture to continue along its original orientation. Both of these effects favor the initiation of a horizontal fracture, and neglect of their influence therefore represents a built-in safety factor. Since the ability of the fracture to change its orientation cannot be evaluated, the value of this safety factor cannot be estimated.

A further built-in safety factor is present in the analysis in the assumption that a failure condition has been reached when any point exhibits an equal possibility for vertical or horizontal fractures. By restricting the injections, the critical point can be avoided. Furthermore, even if an injection was initiated at the critical point, the stress distribution in the rock a short distance away would favor a horizontal fracture.

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[6] R. O. Kehle, "The Determination of Tectonic Stresses Through Analysis of Hydraulic Well Fracturing," *J. Geophys. Res.* 69(2), 259–73 (Jan. 15, 1964).

Still another built-in safety factor is implicit in the assumption that the critical points from the individual injections are superimposed. In the actual case the injections or groups of injections are spaced vertically along the injection well, which would distribute the critical points. The induced stresses would not therefore be directly superimposed, and the net stresses at the overall critical point would build up much more slowly. This effect could be included in the analysis by making a series of assumptions about the spacing between slots, the volume injected at each slot, and the extent of the various sheets.

Conclusions

The ultimate capacity of the shale formation at the present site as estimated from rock mechanics considerations and within the limitations of the analysis appears to be greater than that required for the economic feasibility of the method.[7] Based on the analysis of the failure mechanism, a number of recommendations can be made to avoid, as much as possible, the conditions leading to failure by the formation of a vertical fracture. The most important of these recommendations are as follows:

1. As many injections as possible should be made into a single slot and a minimum distance maintained between slots. This procedure will tend to increase the mean diameter of the grout sheets relative to the thickness, which in turn decreases the P_0 pressure and also places the critical point at the maximum distance above the sheets.
2. The viscosity of the slurry should be as low as possible, in an effort to increase the horizontal dimensions of the sheets.
3. No injection should be made higher than 0.3 times the grout sheet radius above the first injection. This will prevent the injection of wastes into the area of the critical points and should not unduly restrict the life of the well. For example, at the plant site, the first injection was at 945 ft, with an indicated radius of 670 ft; the minimum depth for injections would be

   $$Z = 945 - (0.3)\,670 = 744 \text{ ft} .$$

4. The formation of a vertical fracture may be indicated during the breakdown, not the injection, phase. Therefore both the breakdown pressure and an instantaneous shut-in pressure should be observed and recorded. If either of these pressures, referred to static conditions at the level of the fracture, is less than the overburden pressure, a vertical fracture is indicated, and the injection should not be made into it. It would be advisable at this stage to move up to a higher level and try again before abandoning the well. Analysis of these pressures before waste slurry is injected into the fracture will therefore prevent a release of activity, and the few hundred gallons of water injected with the fracturing procedure should not extend a vertical fracture far enough to allow entry of groundwaters.

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[7]H. O. Weeren, "Cost Estimates for Hydrofracture Facilities," memo to E. G. Struxness, June 21, 1963.

13. Preliminary Cost Evaluation

No engineering report is complete without a discussion of the costs involved, and this chapter is an attempt to evaluate the cost of waste disposal by hydraulic fracturing. The first part summarizes the actual cost experience at the Oak Ridge plant, including the capital investment in plant and equipment and the operational costs. The second part considers the relative contributions to total cost of the various cost components and the effects of widely varying conditions. Hopefully, this analysis will provide some insight into the expected cost of using the method at other sites.

COST EXPERIENCE AT ORNL

Several major difficulties were encountered in the effort to collect data on the costs actually incurred at the Oak Ridge plant.

The first of these was the fact that construction of the plant was started nearly five years ago. Although a finely detailed breakdown of these expenses probably could have been obtained, the data are so deeply buried that the effort required to retrieve them was considered to be excessive.

Second, the development program was very much a team effort involving personnel from several divisions within the Laboratory and several outside contractors. This division of responsibility, while necessary to the success of the program, further obscured the cost data and made it difficult to carry a complete running summary during the course of the program.

Finally, the most serious difficulty was the fact that in this type of situation, it is almost impossible to separate the costs associated with the research function from those attributable to operation. Since only the operational costs were desired, every cost item had to be examined and a decision made as to what part of the expense, if any, would have been incurred in an operating plant. As a consequence of this disregard of the research costs associated with the operations, it was necessary to discard the operational data from the first four experimental injections. These injections were primarily concerned with the testing and checking of the plant and equipment and therefore would grossly misrepresent actual operational costs. Salary costs for the scientific and research personnel associated with the project were excluded also.

Most of the cost figures were obtained from actual invoices or work orders. Where this was not possible, the figures were estimated based on published prices or standard cost-estimating procedures. Only in a few cases was it necessary to rely on someone's memory of the situation or to make a "ball park" cost estimate of a specific item.

Capital Costs

The capital costs actually incurred in the design and construction of the hydraulic fracturing plant at Oak Ridge are shown in Table 13.1. One observation well and one rock cover monitoring well were considered adequate (in light of present knowledge) for starting operations even though eight or ten of each will eventually be constructed at the Oak Ridge site. Both the injection well and the observation well are cased to 1050 ft, and the figures given in Table 13.1 include the costs of the drilling at Oak Ridge, which are somewhat higher than would normally be encountered because of the research requirement of the program. The "plant equipment" item in Table 13.1 includes all the mechanical apparatus installed initially; additional equipment added later is detailed under "modifications." Some of the equipment, particularly the waste storage tanks, was obtained on U.S. Government surplus, and the estimated open market price of this equipment is given as the last entry on Table 13.1. The first subtotal figure of $400,400 represents the initial construction costs of the ORNL fracturing plant. Comparison with the USAEC Directive Authorization figure (dated October 19, 1964) of $400,473 for this work suggests that the summary in Table 13.1 is reasonable and that no major items have been overlooked.

Table 13.1. Actual ORNL Capital Costs

Engineering design		$ 46,300
Injection well		22,600
Observation and rock cover monitoring wells (1 each)		25,800
Plant equipment		
Purchase orders	$146,000	
ORNL labor and overhead	29,873	
Total		$175,800
Plant construction (labor-materials-overhead)		$119,700
Emergency trench		1,200
Waste transfer line extension		9,000
Subtotal		$400,400
Modifications		
Mass flowmeter	$ 5,000	
Dust collection system	3,000	
Modification of waste tanks	25,000	
New power line	27,000	
Total		$ 60,000
Subtotal		$460,400
Estimated purchase price of equipment obtained on surplus		$100,000
Total		$560,400

Operating Costs

The actual operating costs of injections 5 through ILW-2 are itemized in Table 13.2. As was mentioned above, the experimental aspects of the first four injections made it inadvisable to use the cost data from these injections. In the table the Halliburton charges were taken directly from invoices and do not include the expenses of a development engineer who provided engineering assistance for each injection. All the costs of the dry materials were taken from invoices or delivery slips. The quantities delivered to the site usually will be slightly greater than those required for a given mix formulation. This is because of the allowance for spillage and for material used both before and after the wastes are injected. Therefore the dry material cost per gallon may not agree exactly with the theoretical unit costs. The "ORNL services" are based on the manpower requirements during an injection and immediately preceding the injection (for dry solids

Table 13.2. Operating Costs

Injection:	5	6	7	ILW-1	ILW-2
Date:	May 28, 1964	May 19–22, 1964	Aug. 16, 1965	Dec. 12–13, 1966	Apr. 20–24, 1967
Volume waste (gal):	148,000	64,000	95,000	62,000	148,000
Halliburton (labor and expenses)	$ 5,955	$ 7,386	$ 5,205	$ 5,939	$ 5,329
Dry materials					
Sand	$ 112	$ 112	$ 66		$ 74
Cement	10,766	4,260	2,069	$ 1,526	3,615
Attapulgite	1,210	1,166	1,166	814	2,535
Grundite	609	348	348	310	642
Sugar	905	240	240	240	120
Fly ash			532	162	368
Transportation			656	496	
TBP				482	482
Total dry materials	$13,602	$ 6,126	$ 5,077	$ 4,030	$ 7,836
ORNL services (labor and overhead)	$ 3,200	$ 5,760	$ 2,880	$ 2,560	$ 2,000
ORNL incidentals	2,000	2,000	2,000	2,000	2,000
HP services	150	300	150	300	300
Specials		6,401			1,614
Total operating cost	$24,907	$27,973	$15,312	$14,829	$19,079
Dry materials cost per gallon of waste	$ 0.134	$ 0.096	$ 0.053	$ 0.065	$ 0.053
Total operating cost per gallon of waste	$ 0.169	$ 0.437	$ 0.161	$ 0.239	$ 0.129

blending). The "ORNL incidentals" item is an estimate of the amount of work done at the plant between injections in the form of routine inspection, maintenance, and cleanup. Both of the ORNL items include an overhead factor consisting of electrical power, water, fuel, administration, and security. At ORNL these charges are distributed according to the man-hours of effort, and there is no way to obtain even an estimate of actual overhead at the hydraulic fracturing plant. It was necessary to include a "specials" charge for injections 6 and ILW-2 to cover the unusual and nonrecurring expense of equipment malfunction. For injection 6, this charge includes $1725 for the purchase of contaminated material from the Halliburton Company and $4676 to construct another waste pit. During injection ILW-2, $918 was spent to replace contaminated Halliburton equipment and $696 on decontamination. The difficulties with injection 6 are reflected in the abnormally high cost per gallon of waste ($0.44).

The cost of pumping waste to the disposal site (except for the installation of the line) is not included as an operational expense. This charge would be incurred regardless of the method of waste disposal employed and should be considered in any waste management evaluation but perhaps should not be charged directly to the disposal operation. No charges were made for the core drilling and logging, the rock cover well monitoring, or the surface uplift measurements. These were considered to be within the realm of research. However, in any disposal facility, it will be necessary to monitor underground dispersion of the grout sheets and the response of the cover rock in some as yet unspecified way.

COST PROJECTION

In order to examine the costs of operating a hydraulic fracturing waste disposal plant under a wide range of conditions such as might exist at some other (especially commercial) site, it is necessary to make several assumptions concerning the unit costs. These assumed values are given in Table 13.3. The $800,000 capital investment figure was estimated from the Table 13.1 total of $560,000 (in 1963 dollars), which at normal price increases would now be worth nearly $700,000,

Table 13.3. Projected Costs of Disposal by Hydrofracturing

Capital investment (in 1968 dollars) (plant, equipment, construction, and overhead, including one observation well and one rock cover monitoring well)	800,000 (55,000/year)[a]
Dry solids ($/gal)	0.06
Injection operating crew ($/injection) (Halliburton)	6,000
ORNL support ($/injection) (maintenance, blending, health physics, etc.)	4,000
Monitoring ($/year)	25,000

[a]Amortized over 20 years at 4% interest per annum.

and by assuming that an operating facility might necessitate a somewhat larger capacity or higher quality equipment amounting to about an additional $100,000.

This estimate of the plant capital costs, being based on the Oak Ridge experience, tacitly assumes that the postulated plant is of about the same size and of similar design. Conditions at any real proposed plant may be so different that the cost projections presented here are no longer valid. For example, on-site waste storage may not be necessary, thereby eliminating the sizable expense of the tanks, or the waste production rate may be several million gallons per year, necessitating a complete redesign of the mechanical equipment.

Both the operating experience at the ORNL plant and the theoretical work on mix development indicate that a dry solids cost of $0.06 per gallon can be maintained easily and that it will be very difficult to reduce this figure appreciably without a relaxation of present mix specifications. The estimate of $6000 per injection for the operating crew is based on Halliburton costs to date (Table 13.2) and can be expected to continue at about the same rate regardless of the choice of a subcontractor to provide this service. Also, our operating experience indicates that each injection will require approximately $4000 for ORNL labor and overhead, principally for blending the dry solids, health physics monitoring, maintaining the equipment between injections, testing the mix formulation for particular wastes, and other incidentals.

A charge of $25,000 per year was estimated to cover the cost of monitoring the underground behavior of the grout sheets and the behavior of the cover rock. This figure was obtained by assuming that, regardless of the eventual monitoring procedures and the utilization rate of the disposal formation, monitoring would require approximately one-half time of a professional engineer and an average of $10,000 per year of services (in the form of coring, logging, and/or surface leveling) for the lifetime of the plant. This estimate of the cost of monitoring, which represents a sizable proportion of the total cost of disposal, contains a fairly large safety factor to cover our present deficiency in predicting failure modes, especially of the rocks confining the wastes in a safe configuration. As knowledge of and experience with the Oak Ridge facility is gained, it should be possible to reduce this charge by an appreciable amount.

No charge was made against the disposal operations for the acquisition of land at the disposal site. Presumably, any disposal operation would be associated with some type of nuclear chemical plant, which, by its very nature, will require a sizable reservation. The disposal site will be located somewhere within this reservation. It will be necessary to carry out an extensive site testing program to confirm the applicability of hydraulic fracturing at any proposed site. The cost of this testing program may be significant and should be charged against the disposal operation as a capital expense. It was not included in this analysis because it is not yet possible to even estimate the cost of this site testing program. This aspect of disposal by hydraulic fracturing is currently under investigation at ORNL.

The variation of the unit disposal cost (dollars per gallon) as a function of both the waste production rate and the size of each injection is shown in Fig. 13.1. This figure was constructed by assuming that the capital investment funds were borrowed at an interest rate of 4% per annum and

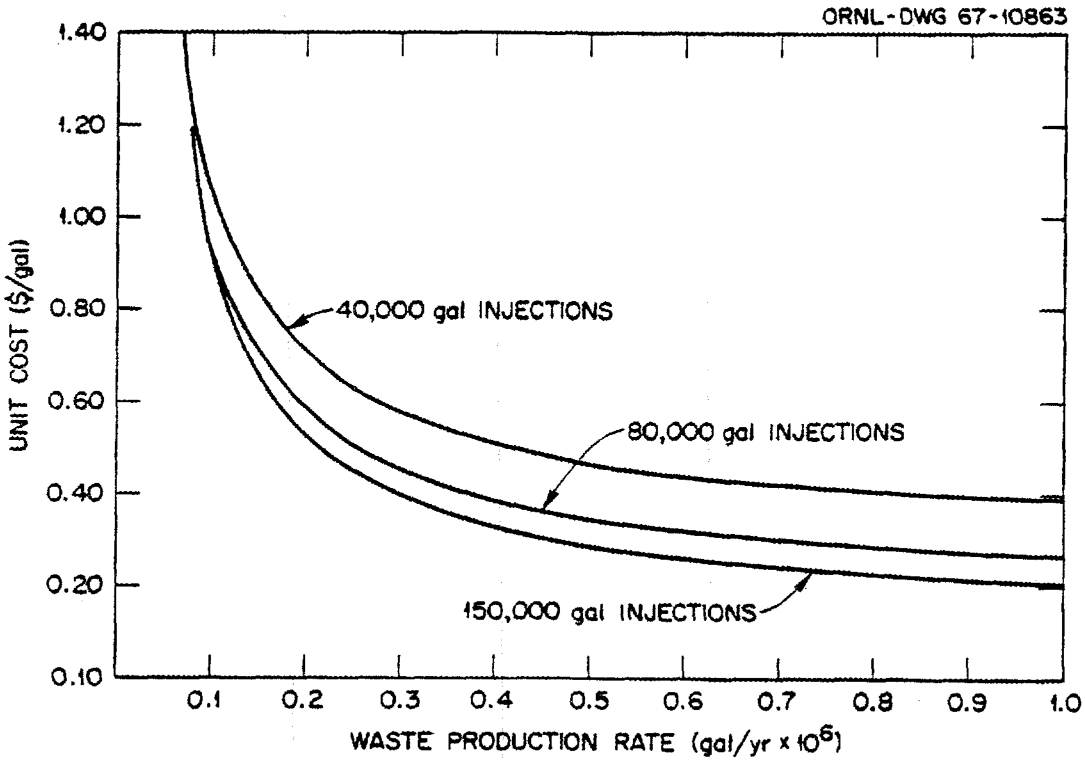

Fig. 13.1. Unit Cost as a Function of Waste Production Rate and Volume of Individual Injections.

repaid in 20 equal installments of $55,000. The life of the plant was assumed to be 20 years, at which time none of the equipment was considered to be worth salvaging. The capacity of the shale formation into which the injections are made was assumed to be greater than the 20-year waste production. As can be expected with this type of operation, the unit costs decrease very rapidly as the rate of utilization (waste production rate) increases. The unit costs also decrease as the size of the individual injection is increased. Both of these factors will be examined in more detail below. The unit costs shown in Fig. 13.1 range from over $1.00 per gallon for a 40,000-gal injection every five months (100,000 gal/year) to approximately $0.20 per gallon when a million gallons of waste per year are disposed in 150,000-gal injections.

Figure 13.1 suggests that further increases in the size of each injection above 150,000 gal will serve to decrease the overall cost by much smaller amounts. This is borne out in Fig. 13.2, where the influence of the size of the injected batch is shown over a wide range. This figure was constructed using the same assumptions as for Fig. 13.1 with a waste production rate of 400,000 gal/year. As can be seen, above a batch size of 160,000 gal, only about $0.01 per gallon, or 3%, is saved for each 40,000-gal incremental increase in batch size. This result is obtained even under an assumption that larger injections can be carried out without increasing the operational costs, which are largely labor. Actually, there would be a small increase in these charges and a slight increase in capital expenditure for larger on-site tank storage capacity. This would tend

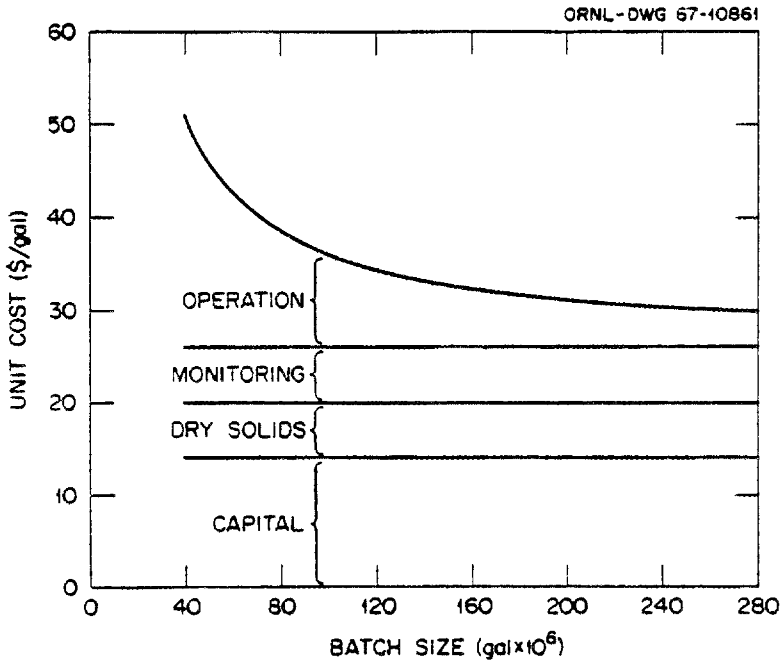

Fig. 13.2. Influence of Size of Individual Injections on Breakdown of Costs.

to flatten out the curve of Fig. 13.2 even more. It would appear therefore that for waste production rates of up to about a million gallons per year, the present routine batch size of 150,000 to 160,000 gal used at ORNL is probably about optimum. At a waste production rate of 400,000 gal/year, this size of injection will cost about $0.32 per gallon. The relative contributions of the several factors making up this total cost are also shown in Fig. 13.2. These are, per gallon: dry solids, $0.06 (as per assumptions in Table 13.3); monitoring, $0.06; capital, $0.14; and operation, $0.06. Further significant cost reductions in the dry solids and operations areas due to technological developments do not appear promising at this time, and the monitoring charge probably represents a minimum estimate. Therefore it would appear that any future reductions in the unit cost would require a manipulation of the capital charges, and this is outside the scope of the present evaluation.

These capital charges are less significant if the equipment is utilized at a greater rate (larger rate of waste production) and much more significant at a lesser rate of utilization. This feature is shown in Fig. 13.3, where the cost components are plotted as a function of the waste generation rate for an injection batch size of 150,000 gal. Of course, the unit cost continues to decrease with increasing utilization, but this reduction becomes less significant at waste production rates above about 500,000 gal/year. This suggests that (from the cost point of view), optimum utilization of disposal by hydraulic fracturing will require a facility such as a chemical reprocessing plant which produces at least 400,000 to 500,000 gal of wastes per year. Other considerations, such as safety, may lower this minimum requirement.

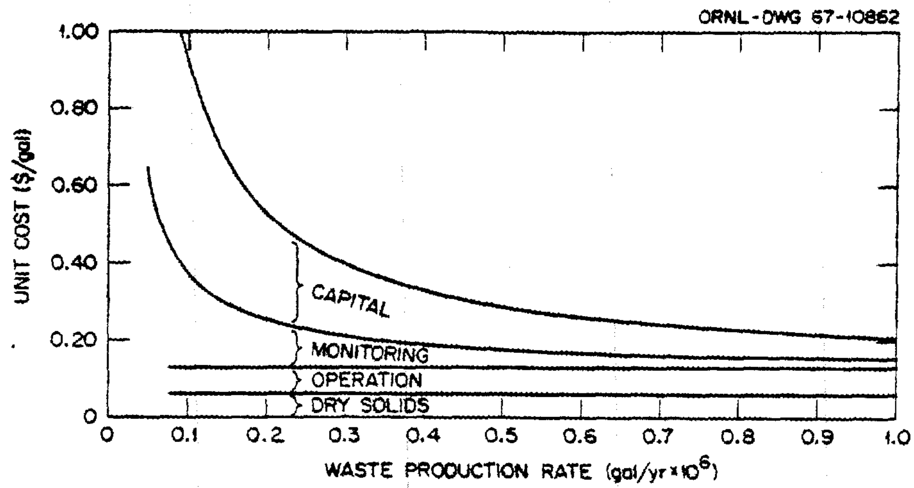

Fig. 13.3 Influence of Waste Production Rate on Breakdown of Costs.

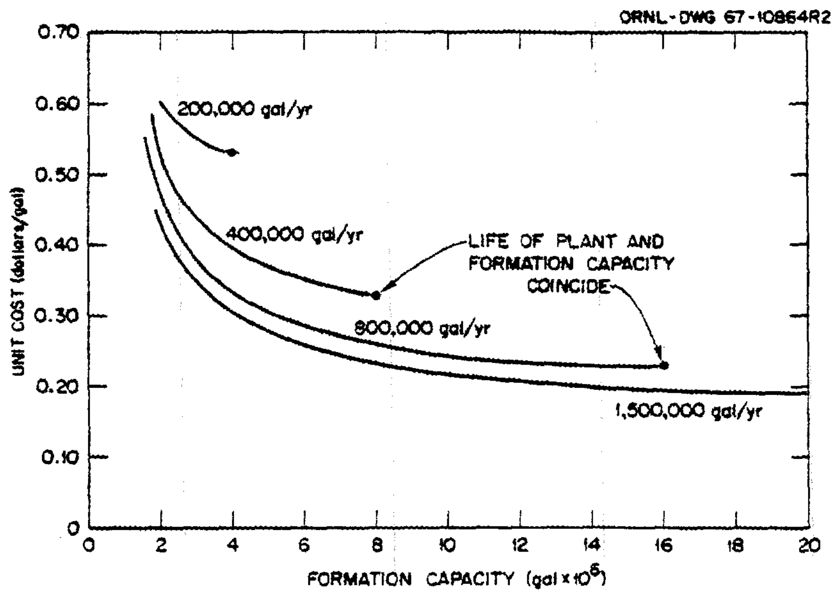

Fig. 13.4. Influence of Formation Capacity on Unit Cost of Disposal.

Previous investigations of the mechanical behavior of the host shale into which the slurries are injected[1] suggest that the capacity of the shale formation may be limited. This limit might require the construction of a new disposal facility at intervals of less than the 20 years which was assumed in the previous discussions. The effect of this limited capacity of the formation on the unit costs of disposal is shown in Fig. 13.4. This figure was constructed by assuming

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[1] R. E. Blanco and F. L. Parker, *Waste Treatment and Disposal Semiannual Progress Report, July to December 1966*, ORNL-TM-1887 (November 1967), p. 81.

that \$250,000 of the capital investment would be in the form of pumps, engines, tanks, and other equipment which have a 20-year usable lifetime and which can be salvaged at any time up to 20 years. The remaining \$550,000 capital would have been invested in wells, buildings, and construction labor and would have a lifetime equal to that required to fill the capacity of the formation. These two items were then amortized over their respective periods (at 4%) to give the annual and unit capital charges. If the capacity of the formation is taken to be 4×10^6 gal, there is no cost penalty when the waste production rate is less than 200,000 gal/year, since all of the equipment would have to be replaced (assuming a 20-year life) before the capacity of the formation had been reached. At a waste production rate of 400,000 gal/year, a capacity of 4×10^6 gal would raise the unit cost from \$0.33 to \$0.395 per gallon. However, if the capacity of the formation is 8×10^6 gal, there would again be no penalty. In general, for a 4×10^6-gal capacity, there would be a small cost penalty at higher waste production rates, but this penalty becomes insignificant for all waste production rates if the limiting capacity can be raised to 8 or 10×10^6 gal.

CONCLUSIONS

Although the hydraulic fracturing disposal operations carried out at ORNL were largely devoted to research and development of the technique, some of the cost experience can be used as a basis for estimating the unit costs of an operating facility. Based on the analyses presented above and within the constraints of the assumptions, it is possible to draw several relevant conclusions concerning the economics of waste disposal by hydraulic fracturing:

1. An optimum-size injection would appear to be in the range of 120,000 to 180,000 gal.
2. To be most advantageous economically, a hydraulic fracturing disposal plant should be utilized at the rate of at least 400,000 to 500,000 gal/year.
3. A formation with a capacity limited to 4×10^6 gal would exact only a small financial penalty from the operation, while a capacity of 10^7 gal represents no penalty at all.
4. With a plant disposing of 400,000 gal/year in 150,000-gal batches, the unit cost would be expected to be about \$0.30 to 0.35 per gallon, of which \$0.12 to 0.15 per gallon represents the capital investment charges. This unit cost will be much smaller if the size of the plant is significantly increased in order to handle much larger volume.

This estimated unit cost can be compared with an estimated \$0.30 to \$0.35 per gallon[2] for permanent tank storage of intermediate-level wastes and is well within a competitive range with other treatment and disposal methods for intermediate-level wastes.

COST OF FIRST AND SECOND FRACTURING EXPERIMENTS

The costs of the two preliminary experiments are shown in Table 13.4. The figures are of interest in themselves, and they suggest the scale of operations required for a very complete site investigation. However, the test program required to determine if a new site were suitable for disposal by hydraulic fracturing could well be substantially less expensive.

[2]J. O. Blomeke, private communication.

Table 13.4. Costs of Fracturing Experiments

	First	Second
Site preparation	$ 6,387.85	$ 10,890.00
Injection operation	6,814.86	27,396.08
Test drilling (to Oct. 1, 1961)	18,254.85	67,079.47
Preinjection core hole		5,438.30
Injection well		6,778.95
Incidentals	2,737.14	813.44
ORNL support (includes tiltmeters)		21,026.55
	$34,194.70	$139,422.79
Total, both experiments		$173,617.49
Deep test hole (3263 ft)		$ 13,899.25
ORNL support		5,220.91
Incidentals		34.21
		$ 19,154.37
Grand total		$192,771.86

Appendix

PRESSURE DROP FOR NON-NEWTONIAN FLUIDS

The flow equations for non-Newtonian fluids are as follows:

$$N_{Re} = \frac{1.86V^{2-n'}\rho}{K'(96/D)^{n'}} ,$$

$$\Delta P_f = \frac{0.039L\rho V^2 f}{D} ,$$

where

ΔP_f = pressure drop (psi),
V = fluid velocity (fps),
ρ = fluid density = 14.1 lb/gal for this slurry,
D = diameter (in.),
L = length = 1000 ft (assumed),
n' = 0.84 for this slurry (dimensionless),
K' = 0.0099 for this slurry (dimensionless),
N_{Re} = Reynolds number (dimensionless).

For a flow of 500 gpm in tubing with D = 2.441 in.,

$$V = 500\left(\frac{231}{60}\right)\left(\frac{1}{4.68}\right)\left(\frac{1}{12}\right) = 34.3 \text{ fps} ,$$

$$N_{Re} = \frac{1.86\,(34.3)^{1.16}\,(14.1)}{0.0099\,(96/2.441)^{0.84}} = 7270 ,$$

$$f = 0.0056 ,$$

$$\Delta P_f = \frac{0.039\,(1000)\,(14.1)\,(34.3)^2\,(0.0056)}{2.441}$$

$$= 1480 \text{ psi} .$$

In an annulus with

$$D_e = \frac{4\ (10.6)}{\pi(4.67 + 2.875)} = 1.79 \text{ in.}$$

and

$$A = \pi/4\ (4.670^2 - 2.875^2) = 10.6 \text{ in.}^2 ,$$

for a flow of 500 gpm

$$V = 500\left(\frac{231}{60}\right)\left(\frac{1}{10.6}\right)\left(\frac{1}{12}\right) = 15.1 \text{ fps} ,$$

$$N_{Re} = \frac{1.86\ (15.1)^{1.16}\ (14.1)}{0.0099\,(96/1.79)^{0.84}} = 2230 ,$$

$$f = 0.007 ,$$

$$\Delta P_f = \frac{0.039\ (1000)\ (14.1)\ (15.1)^2\ (0.007)}{1.79}$$

$$= 490 \text{ psi} .$$

VELOCITY ATTAINED BY A PIPE FRAGMENT IN THE EVENT OF A RUPTURE

Particles 1 in. in diameter and smaller can go through the interstices of the roof grating and hit the $\frac{1}{4}$-in.-thick roof plate. Particles larger than 1 in. in diameter will hit the roof grating and thus distribute the impact load. Since the hazard is different, the two cases are considered separately.

During an injection the wellhead components are chained to the floor of the cell. They are also further restrained by piping connections, valve handles, etc. The largest unrestrained piece of equipment that seems likely to become a missile in the event of a rupture is a fragment of the plug container, which is on the top of the wellhead assembly. A sudden fracture of this piece of equipment could propel a 50-lb mass against the hatch of the wellhead cell with appreciable velocity. This possibility is considered in detail below.

Assumptions

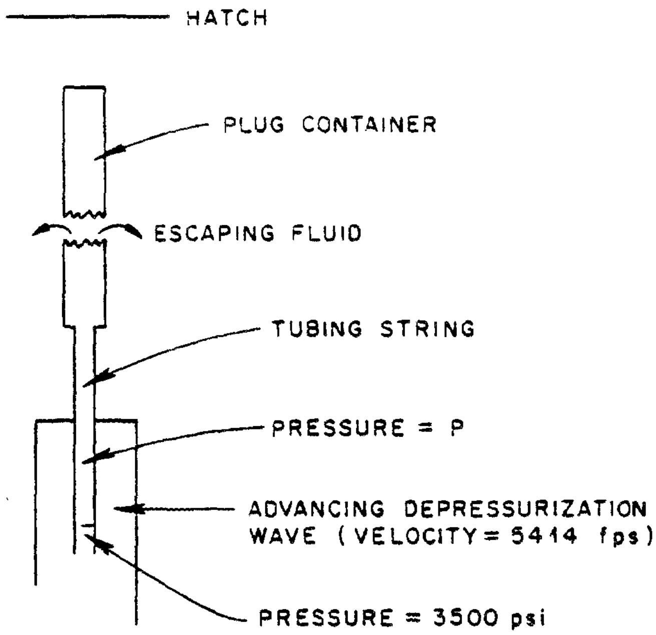
1. Injection pressure is 3500 psi. Piping is filled with grout (ρ = 14.1 lb/gal).
2. Compressibilities of grout and water are identical. (No data on grout compressibility are available.)
3. Depressurization will proceed down the grout-filled tube at sonic velocity (5414 fps).

Data

Diameter of plug container, 3.5 in. = 0.291 ft.

Cross-section area of tubing string, 0.0325 ft^2.

A sketch of the situation being considered is shown below.



Method of Solution

A short time interval is chosen. In this interval the plug container will have been forced upward a short distance by the fluid pressure, a small quantity of fluid will have escaped through the crack formed by the upward movement of the plug container, and the depressurization wave will have traveled a short distance down the tubing string. A mass balance that equates the volume increase of the depressurized fluid with the sum of the volume of fluid escaping and the volume increase caused by the movement of the plug container is used to determine the pressure in the depressurized region. With the fluid pressure known, the velocity of the plug container and the distance traveled during the time interval can be calculated. Another time interval is then chosen, and the above calculation is repeated.

For $t = 0.0005$ sec:

length of pipe depressurized = 5414 (0.0005) = 2.707 ft,

weight of volume increment = (density difference) (volume depressurized):

$$\Delta w = 0.0325\ (2.707)\ (\rho_{3500} - \rho) \left(\frac{14.1}{8.33}\right)$$

$$= 0.149\ (62.6409 - \rho)\ \text{lb}\ ,$$

$$\text{weight of fluid escaping through crack} = \pi D \rho \frac{14.1}{8.33} \text{(orifice velocity) (acceleration of plug container)} \frac{t^3}{6} ,$$

$$\text{orifice velocity} = 0.61(2g\ \Delta H)^{1/2} .$$

(For terms that are pressure dependent, an average of the initial and final values is used.)

$$\text{orifice velocity} = 0.61 \left[64.4p \ \frac{144}{(14.1)\ (7.48)} \right]^{1/2}$$

$$= 5.74\,p^{1/2} \text{ fps}$$

$$= 5.74 \ \frac{(3500)^{1/2} + p^{1/2}}{2} = 2.87\ (59 + p^{1/2}) ,$$

$$\text{acceleration} = \frac{\text{force}}{\text{mass}} - 32.2 = \frac{(p)\ (0.052)(32.2)}{50} - 32.2$$

$$= 4.83p - 32.2 \text{ ft/sec}^2$$

$$= \frac{16900 + 4.83p - 64.4}{2} .$$

Thus

$$\text{weight of fluid escaping} = \pi\ (0.291)\ \frac{14.1}{8.33}\ \rho (2.87)\ (59 + p^{1/2}) \left(\frac{16900 + 4.83p - 64.4}{2} \right)$$

$$\times \left(\frac{0.125 \times 10^{-9}}{6} \right)$$

$$= 4.64 \times 10^{-11}\ \rho (59 + p^{1/2})\ (16900 + 4.83\,p - 64.4) ,$$

volume expansion (due to movement of plug container)

$$= \text{(area) (distance moved) (density)}$$

$$= 0.052\rho\ \frac{14.1}{8.33} \text{ (acceleration)} \left(\frac{t}{2} \right)^2$$

$$= 0.0878\rho\ \frac{(16900 + 4.83p - 64.4)}{2}\ \frac{(0.25 \times 10^{-6})}{2}$$

$$= 5.49 \times 10^{-9} \rho (16900 + 4.83p - 64.4) ,$$

weight of volume increment = weight of fluid escaping plus weight of volume expansion:

$$0.149\,(62.6409 - \rho) = 4.64 \times 10^{-11} \rho (59 + p^{1/2}) (16900 + 4.83p - 64.4)$$

$$+ 5.49 \times 10^{-9} \rho (16900 + 4.83\,p - 64.4) .$$

Values of specific volume of water as a function of pressure are shown in Fig. A.1.

A trial and error technique is used to solve the above equation. The pressure at $t_1 = 0.0005$ is thus found to be 2750 psi. Then

$$\text{fluid increment} = 0.01985\,,$$

$$a = \text{average acceleration} = \frac{16900 + 13235}{2} = 15067\ \text{ft/sec}^2\,,$$

$$\text{velocity at } t = 0.0005 = 7.53\ \text{fps}\,,$$

$$\text{distance at } t = 0.0005 = \frac{at^2}{2} = 0.00188\ \text{ft}\,.$$

In this fashion the fall of pressure in the wellhead is calculated. This change of wellhead pressure and also the missile velocity are shown in Fig. A.2. The maximum missile velocity is about 16 fps.

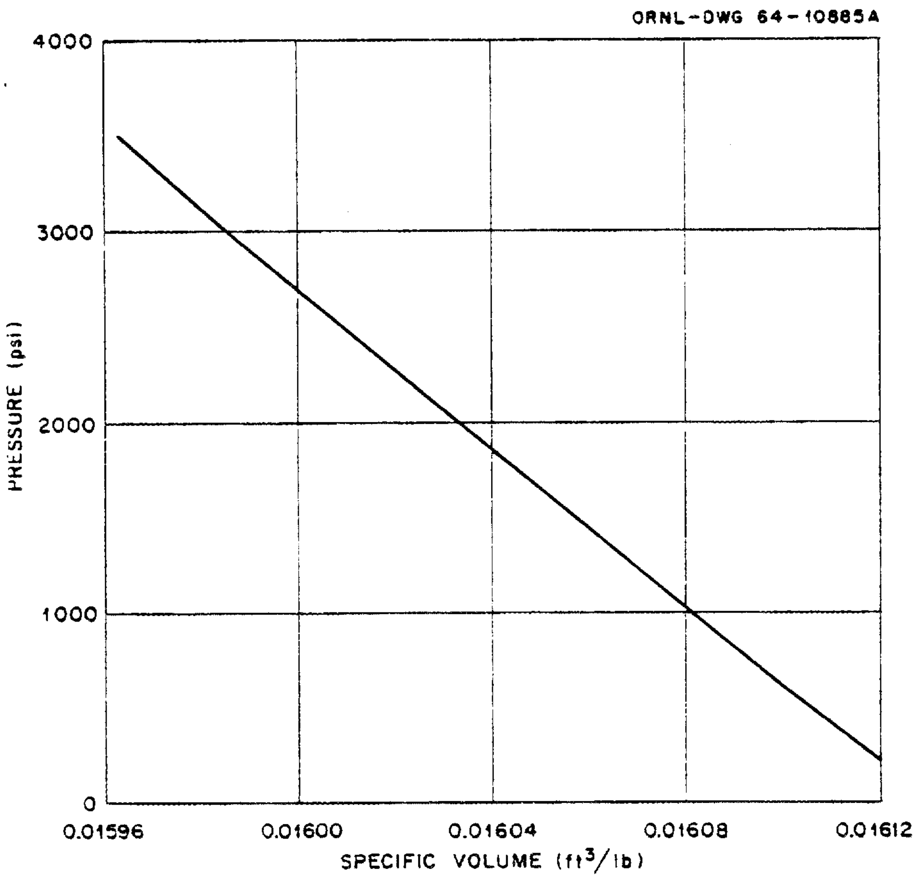


Fig. A.1. Density of Compressed Water. (From *Thermodynamic Properties of Steam*, Keenan and Keyes.)

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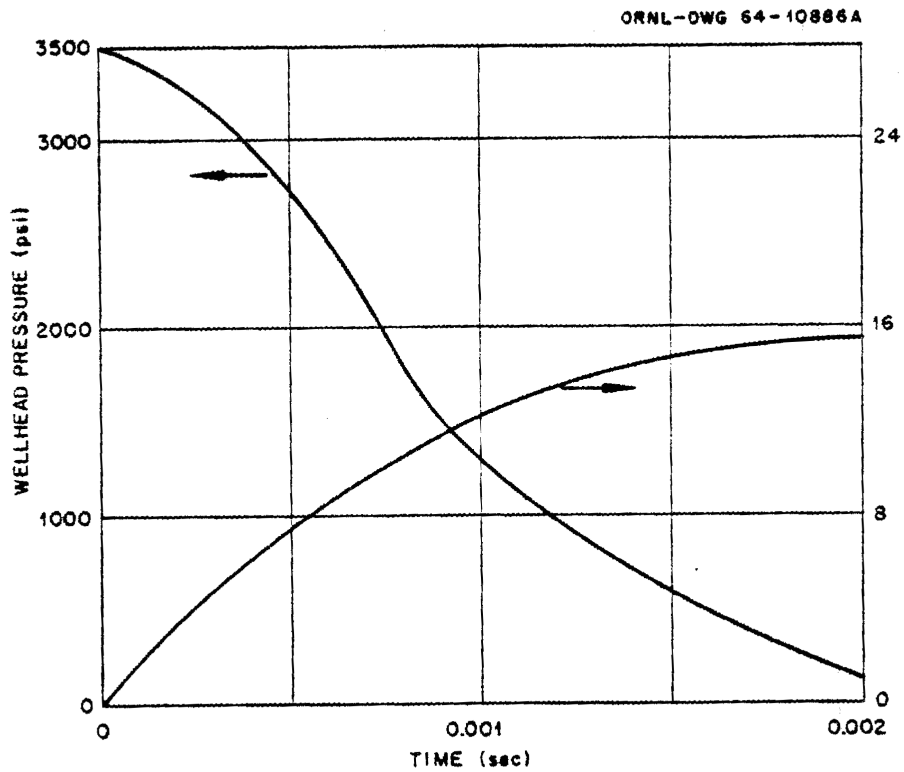

Fig. A.2. Pressure Decrease and Missile Velocity Following a Wellhead Rupture.

The hatch of the wellhead cell is 2 ft 8 in. above the plug container. With an initial velocity of 16 fps,

$$2.667 = V_0 t - \frac{at^2}{2} = 16t - 16.1t^2 ;$$

from this equation it is found that

$$t = 0.208 \text{ sec}$$

and thus the impact velocity will be given by:

$$V = 16 - 32.2(0.208) = 9.7 \text{ fps} .$$

The hatch is 3 ft square. It is constructed of $\frac{3}{4}$-in. steel grating covered with a $\frac{1}{4}$-in. steel plate. The hatch is held down by eight bolts $\frac{1}{2}$ in. in diameter.

For calculation of the impact load the following assumptions are made:

1. The grating will distribute the impact load to the periphery of the grating.
2. Upon impact, the missile is decelerated at a constant rate.
3. Impact loading is twice the static loading.
4. The hatch is circular, not square.

A stopping distance is assumed. The deceleration rate and force required to produce this rate are calculated. If

$$d = 0.1 \text{ in.} = 0.00833 \text{ ft},$$

then

$$0.00833 = 9.7t - \frac{at^2}{2},$$

$$V_f = 0 = 9.7 - at.$$

Thus

$$0.00833 = 9.7t - \frac{9.7t}{2},$$

from which

$$t = .00172 \text{ sec},$$

$$a = 5630 \text{ ft/sec}^2,$$

$$F = \frac{50 \text{ lb}}{32.2}(5630) = 8750 \text{ lb}.$$

For a circular plate, edges fixed and the load distributed in a ring, the equations for deflection and stress are:[1]

$$\max y = \frac{3w(m^2-1)}{2\pi E m^2 t^3}\left[\frac{1}{2}(a^2 - r_0^2) - r_0^2 \log \frac{a}{r_0}\right],$$

$$S_r = \frac{3w}{2\pi t^2}\left(1 - \frac{r_0^2}{a^2}\right).$$

For $a = 18$ in. and $r_0 = 16$ in., these formulas simplify to

$$\max y = 3.47 \times 10^{-6}\, w,$$

$$S_r = 1.605w.$$

For the assumed 0.1 in. deflection, $w = 28{,}800$ lb. This is greater than twice the force calculated above, so the calculation is repeated with a smaller assumed deflection. The final values are

[1] R. S. Roark, *Formulas for Stress and Strain*, 3d ed., p. 196, McGraw-Hill, New York.

$y = 0.093$ in.,

$w = 22{,}500$ lb,

$S_r = 36{,}000$ psi.

This value for S_r is well below the yield stress.

If the shear stress on the tie-down bolts is evenly distributed, a force of 62,700 lb would be required to shear these bolts. The calculated force is well below this value. However, an uneven shear stress distribution could be troublesome.

A small pipe fragment could be formed by the rupture of any piece of high-pressure equipment. For the calculation of the fragment velocity, it is assumed that the propelling force is exerted until the fragment has traveled beyond the wall of the pressure container; after this the propelling force drops to zero.

The fragment is assumed to be 1 in. in diameter and 0.81 in. thick:

$$\text{mass} = \frac{\pi}{4}(1)^2\,(0.81)\,\frac{480\ \text{lb/ft}^3}{1728} = 0.1767\ \text{lb}\ ,$$

$$\text{acceleration} = \frac{(3500\ \text{psi})\,(0.785\ \text{in.}^2)\,(32.2)}{0.1767} - 32.2$$

$$= 500{,}000\ \text{ft/sec}^2\ ,$$

$$\text{distance} = 0.5\ \text{in.} = 0.0417\ \text{ft} = \frac{at^2}{2}\ ,$$

$$\text{time} = \left[\frac{0.0417\,(2)}{500{,}000}\right]^{1/2} = 4.08 \times 10^{-4}\ \text{sec}\ ,$$

$$\text{velocity} = at = 5 \times 10^5\,(4.08 \times 10^{-4}) = 204\ \text{fps}\ ,$$

$$\text{kinetic energy} = \frac{1}{2}\,mv^2 = \frac{1}{2}\,\frac{0.1767}{32.2}\,(204)^2 = 114\ \text{ft-lb}$$

$$= 114\ \text{ft-lb/in.}$$

This is far below the 1400 ft-lb/in. required to penetrate a $\frac{1}{4}$-in. plate.

The impact force of a 50-lb mass with a velocity of 10 fps against the concrete block wall of the cell is calculated from the formula

$$F = \frac{2mv}{t}\ ,$$

where[2]

$$t = \text{time of impact} = \frac{\pi}{2}\left(\frac{m}{2\pi P}\right)^{1/2}$$

$$= \frac{\pi}{2}\left[\frac{50}{32.2}\left(\frac{1}{2\pi 3500\ (144)}\right)\right]^{1/2} = 2.9 \times 10^{-3}\ \text{sec}\ ,$$

$$F = 2\left(\frac{50}{32.2}\right)(10)\left(\frac{1}{2.9 \times 10^{-3}}\right) = 10{,}400\ \text{lb}\ .$$

The actual impact force is usually twice that calculated by the above formula; thus the impact force is about 20,000 lb.

Each concrete block is held in place by about 1200 in.^{2} of mortar. The impact force would produce a shear stress of about 17 psi, far below the mortar strength.

ENTRAINMENT TO WASTE TANK FILTER

Assumed:

Flow per sparger = 4 scfm.

Total flow at one time = 16 scfm.

Solution activity = 0.015 curie/gal (5.6% Sr, 87.5% Cs, 4.9% Ru).

Particle concentration[3] = 10 mg/m^3.

Particle size distribution: as shown in Fig. A.3 (from Fig. 1 of ref. 3).

Filter efficiency = 99.97% for particles larger than 0.3 μ

= 95% for particles between 0.3 and 0.1 μ

= 0% for particles smaller than 0.1 μ.

Concentration of particles in filtered air

$$= 10\ \text{mg/m}^3\ [1 - 0.9997\ (0.835) - 0.95\ (0.08)] = 0.89\ \text{mg/m}^3\ .$$

Solution activity

$$= 0.015\ \text{curie/gal}\left(\frac{1}{3785}\right)\left(\frac{10^6}{10^3}\right) = 0.00396\ \mu\text{c/mg}\ .$$

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[2]D. Tabor, *The Hardness of Metals*, pp. 131–32, Clarendon Press, 1951.

[3]Assumed similar to that calculated in *Hazards Report for Building 2527*, ORNL-CF-60-5-22.

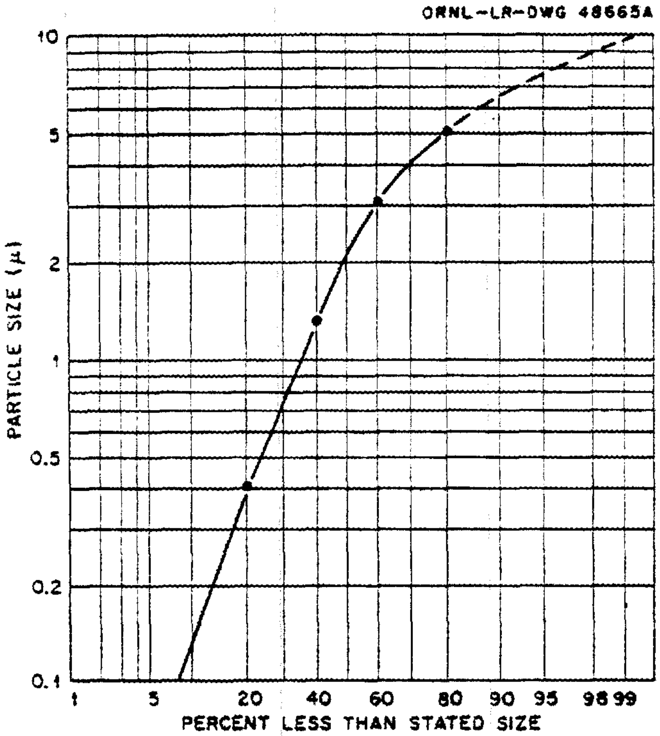

Fig. A.3. Particle Size Distribution of a Stable Aerosol Which Has Encountered Several Changes of Direction in a Pipeline.

Concentration discharged

$$= 0.00396\ (0.89)\left(\frac{1}{28300}\right)\left(\frac{1}{35}\right) = 3.4 \times 10^{-9}\ \mu c/cm^3$$

($1.9 \times 10^{-10}\ \mu c/cm^3$ Sr, $2.98 \times 10^{-9}\ \mu c/cm^3$ Cs, $1.67 \times 10^{-10}\ \mu c/cm^3$ Ru).

Airborne MPC for atomic energy workers for 40-hr week:[4]

$^{90}Sr = 3 \times 10^{-10}\ \mu c/cm^3$.

$^{137}Cs = 6 \times 10^{-8}\ \mu c/cm^3$.

$^{106}Ru = 8 \times 10^{-8}\ \mu c/cm^3$.

Approach to MPC:

$^{90}Sr = 63\%$.

$^{137}Cs = 5\%$.

$^{106}Ru = 0.21\%$.

[4]From report of ICRP Committee on Permissible Dose for Internal Radiation (1959).

MAGNITUDE OF DETECTABLE LEAK IN WASTE TRANSFER LINE

Assumed:

Stream flow at average rate and with average radionuclide composition (Table A.1).

Flow rate = 198×10^6 gal/month.

Activity = 1.02 curies/month.

A reading of twice background indicates a leak.

Waste concentration = 0.015 curie/gal.

Normal background: $\frac{1.02 \times 10^6}{198 \times 10^6}\left(\frac{1}{3785}\right) = 1.36 \times 10^{-6}\ \mu c/ml$.

A leak that contributes $1.36 \times 10^{-6}\ \mu c/ml$ is detectable.

$$\text{Leak rate} = 1.36 \times 10^{-6}\ \frac{(198 \times 10^6) \times (3785)}{30 \times 24 \times 3600}\left(\frac{3785}{0.015 \times 10^6}\right)$$

$$= 0.1\ \text{ml/sec}.$$

Table A.1. Flow and Activity in White Oak Creek

Date	Flow (gal)	Activity (curies)				Reference
		Sr	Cs	Ru	Total	
	$\times 10^6$					
June 1963	149	0.3	0.1	0.03	0.3	CF-63-8-4
May	167	0.4	0.1	0.03	0.5	CF-63-6-44
April	155	0.3	0.1	0.003	0.4	CF-63-5-75
March	563	0.5	0.1	0.3	0.9	CF-63-5-14
February	234	0.3	0.1	0.1	6.3	CF-63-4-3
January	198	0.2	0.1	0.2	0.5	CF-63-3-39
December 1962	181	0.2	0.1	0.1	0.4	CF-63-1-73
November	198	0.2	0.1	0.1	0.4	CF-63-1-23
October	138	0.2	0.1	0.1	0.5	CF-62-12-2
September	149	0.2	0.1	0.1	0.4	CF-62-11-24
August	124	0.2	0.1	0	0.4	CF-62-10-39
July	113	0.6	0.05	0.1	1.3	CF-62-8-78
Total	2369	3.6	1.15	1.19	12.3	
Av	198	0.3	0.096	0.1	1.02	

RADIATION EXPOSURE DOSE RATES

Case A

Five feet from sump tub containing 200 gal of cement grout with 12 in. of concrete shielding.

Assumed waste activity = 0.015 curie/gal.

Grout activity = 0.0112 curie/gal.

Total curies in tub = 0.0112(200) = 2.24.

It is assumed that the waste was irradiated for 3×10^7 sec at a flux of 3×10^{13} and cooled for three years. For these conditions the four energy groups will be present in the ratios given below:[5]

Group	Energy (Mev)	Activity (dis/sec per atom ^{235}U)	Percentage
I	0.15	1.9×10^{-11}	40
II	0.67	2.7×10^{-11}	56.8
III	1.6	1.1×10^{-12}	2.32
IV	2.4	4.0×10^{-13}	0.843

(2.24 curies) $(3.7 \times 10^{10}) = 8.28 \times 10^{10}$ dis/sec in tub.

Group I: $8.28 \times 10^{10}(0.40) = 3.31 \times 10^{10}$ dis/sec $= 4.96 \times 10^{15}$ ev/sec.

Group II: $8.28 \times 10^{10}(0.568) = 4.71 \times 10^{10}$ dis/sec $= 3.15 \times 10^{16}$ ev/sec.

Group III: $8.28 \times 10^{10}(0.0232) = 1.92 \times 10^{9}$ dis/sec $= 3.07 \times 10^{15}$ ev/sec.

Group IV: $8.28 \times 10^{10}(0.00843) = 6.98 \times 10^{8}$ dis/sec $= 1.67 \times 10^{15}$ ev/sec.

It is assumed that the sump tub is shaped like a vertical cylinder 4 ft in diameter and 2 ft high. For a volume source of this geometry:

$$E_A = \frac{\mu S_v R^2}{2(a + z)} F(\phi B^*) ,$$

[5]From J. O. Blomeke and M. F. Todd, *U^{235} Fission Product Production as a Function of Flux, Irradiation Time, and Decay Time*, ORNL-2127.

where

$B^* = \nu z + \Sigma 6t$,

$R = 24$ in. $= 61$ cm ,

$a = 5$ ft $= 152.5$ cm ,

$\phi = 11°$.

Group	E (Mev)	ν	νR	νz	z	S_v	$\nu z + 6t$
I	0.15	0.32	19.5	4.13	12.9 cm	6.55×10^9	14.1
II	0.67	0.2	12.2	3.4	17	4.17×10^{10}	8.93
III	1.6	0.13	7.9	2.74	21	4.07×10^9	6.74
IV	2.4	0.105	6.4	2.34	22.3	2.21×10^9	5.70

$$E_A = \frac{3.5 \times 10^{-5} S_v(3720)}{2(152.5 + z)} F(\phi B^*) ,$$

$$E_{A_I} = \frac{6.51 \times 10^{-2}}{152.5 + 12.9} (6.55 \times 10^9)(1.3 \times 10^{-7}) = 3.36 \times 10^{-1} ,$$

$$E_{A_{II}} = \frac{6.51 \times 10^{-2}}{152.5 + 17} (4.17 \times 10^{10})(2.1 \times 10^{-5}) = 3.36 \times 10^2 ,$$

$$E_{A_{III}} = \frac{6.51 \times 10^{-2}}{152.5 + 21} (4.07 \times 10^9)(1.9 \times 10^{-4}) = 2.9 \times 10^2 ,$$

$$E_{A_{IV}} = \frac{6.51 \times 10^{-2}}{152.5 + 22.3} (2.21 \times 10^9)(6 \times 10^{-4}) = 4.93 \times 10^2 .$$

(Values of ν, νz, and $F(\phi B^*)$ are from APEX-176.)

Buildup factors (from *Nuclear Radiation Shielding*, E. P. Blizard):

Group I	40
Group II	10
Group III	5.5
Group IV	3.3

Dose:

Group I	$40 (3.36 \times 10^{-1})(5.4 \times 10^{-8})$	$= 7.25 \times 10^{-7}$ r/hr
Group II	$10 (3.36 \times 10^2)(5.4 \times 10^{-8})$	$= 1.81 \times 10^{-4}$ r/hr
Group III	$5.5 (2.9 \times 10^2)(5.4 \times 10^{-8})$	$= 8.6 \times 10^{-5}$ r/hr
Group IV	$3.3 (4.93 \times 10^2)(5.4 \times 10^{-8})$	$= 9.05 \times 10^{-5}$ r/hr
Total		0.358 mr/hr

Case B

Four feet above sump tub containing 200 gal of cement grout, no shielding.

$$E_A = \frac{\mu S_v}{2\nu}\left\{\left[1 - F1\,(\nu h)\right] - \left[\frac{1 - F1\,(\nu h \sec\phi_1)}{\sec\phi_1}\right]\right\} ,$$

$h = 2$ ft $= 61$ cm ,

$\sec\phi = 1.118$.

Group	E	S_v	ν	νh	$\nu h \sec\phi$
I	0.15 Mev	6.55×10^9	0.32	19.5	21.8
II	0.67	4.17×10^{10}	0.20	12.2	13.6
III	1.6	4.07×10^9	0.13	7.93	8.9
IV	2.4	2.21×10^9	0.105	6.41	7.17

$$E_{A_I} = \frac{3.5 \times 10^{-5}(6.55 \times 10^9)}{2(0.32)}\left[1 - 19.5\,(8 \times 10^{-12}) - 0.89441 + \frac{21.8\,(6.5 \times 10^{-13})}{1.12}\right]$$

$$= 3.79 \times 10^4 ,$$

$$E_{A_{II}} = 3.86 \times 10^5 ,$$

$$E_{A_{III}} = 5.78 \times 10^4 ,$$

$$E_{A_{IV}} = 3.8 \times 10^4 ,$$

Total $= 5.205 \times 10^5$.

Dose $= 5.205 \times 10^5\,(5.4 \times 10^{-8}) = 0.0281$ r/hr $= 28$ mr/hr .

Case C

Four feet above valve pit, no shielding.

Assuming dose is from two line sources (4-in. pipe), each 14 ft long:

$$E_A = \frac{\mu S_L \phi}{2\pi a} .$$

$$S_L = \frac{12.73\ \text{in.}^2}{231}\,(0.015\ \text{curie/gal})\left(\frac{1}{2.54}\right) = 0.000325\ \text{curie/cm}$$

$$= 0.000325\,(3.7 \times 10^{10})\ 0.15\,(0.4) + 0.67\,(0.658) + 1.6\,(0.023) + 2.4\,(0.008) \times 10^6$$

$$= 6 \times 10^{12} \text{ ev sec}^{-1} \text{ cm}^{-1} ,$$

$$a = 122 \text{ cm} ,$$

$$\phi = 1.4 \text{ radians} .$$

$$E_A = \frac{3.5 \times 10^{-5} (6 \times 10^{12}) (1.4)}{2\pi (122)} = 3.84 \times 10^5 .$$

Dose $= 3.84 \times 10^5 (5.4 \times 10^{-5}) = 20.7$ mr/hr .

Dose from both sources = 41.4 mr/hr .

SPREAD OF CONTAMINATION FROM SLOTTING OPERATION

Assumptions:

1. Contamination on tubing is removed by sand-water slurry during slotting operation.
2. 10% of ^{90}Sr is leached from grout. This assumption is based on leach data.
3. After previous injection 200 gal of wash water containing 0.0015 curie/gal was discharged to the waste pit.
4. A grout thickness of 0.01 in. remains on the interior of the tubing after completion of the previous injection (this assumption is arbitrary).

The source of contamination is the water in the waste pit that is used for the slotting operation.

Activity in pit at start of run:

(200 gal) (0.0015 curie/gal) (0.10) = 0.03 curie in waste pit water.

Activity on tubing string:

$$\left(\frac{2.44 \text{ in.}}{12}\right) \pi \text{ (900 ft)} \left(\frac{0.01}{12}\right) (7.48) \text{ (0.015 curie/gal)} = 0.0537 \text{ curie} .$$

Activity in waste pit water:

$$(0.0537)(0.10) + 0.03 = 0.035 \text{ curie} .$$

Specific activity in water:

$$\frac{0.035}{(12)(12)(5)(7.48)} = 6.5 \times 10^{-6} \text{ curie/gal} .$$

Liquid holdup on 30 ft of tubing (assuming $\frac{1}{32}$ in.):

$$\pi (2.44 + 2.875) \left(\frac{30}{12}\right) \left(\frac{0.031}{12}\right) (7.48) = 0.81 \text{ gal} .$$

Activity holdup:

$$(0.81)\ (6.5 \times 10^{-6}) = 5.25 \times 10^{-6} \text{ curie}.$$

^{90}Sr holdup:

$$(0.056)\ (5.25 \times 10^{-6}) = 2.94 \times 10^{-7} \text{ curie}.$$

Maximum allowable weekly intake:

$$(3 \times 10^{-10}\ \mu c/cm^3)\ (10^{-6})\ (5 \times 10^7\ cm^3/40\ hr) = 1.5 \times 10^{-8} \text{ curie}.$$

TABLE OF INJECTIONS

Injection 1

Date	Feb. 13, 1964
Depth	945 ft
Liquids	
Synthetic waste	37,300 gal
Water for breakdown	3,000 gal
Solids	23,400 lb Attapulgus 150
Slurry volume	40,383 gal
Total volume injected	43,383 gal
Activity	None

Injection 2

Date	Feb. 20 and 21, 1964
Depth	924 ft
Liquids	
Water for breakdown	1,000 gal
Synthetic waste	28,300 gal
Wash water, Feb. 20	3,600 gal
Overdisplacement, Feb. 20	500 gal
Solids	192,000 lb
Slurry volume	37,791 gal
Total volume injected	42,891 gal
Activity	30 curies ^{198}Au

Injection 3

Date	Apr. 8, 1964
Depth	912 ft
Liquids	
Water for breakdown	2,590 gal
Waste	33,500 gal
Water to use up solids	7,000 gal
Solids	529,072 lb
Slurry volume	65,314 gal
Total volume injected	67,944 gal
Activity	74 curies Cs
	4.9 curies Sr
	0.4 curie Ru
	0.1 curie Co

Injection 4

Date	Apr. 17, 1964
Depth	900 ft
Liquids	
Water for breakdown	2,670 gal
Waste	35,900 gal
Water	500 gal
Solids	398,381 lb
Slurry volume	57,467 gal
Total volume injected	60,137 gal
Activity	50 curies Cs
	1.2 curies Ru
	0.9 curie Sr
	0.1 curie Co

Injection 5

Date	May 28, 1964
Depth	890 ft
Liquids	
Water for breakdown	1,992 gal
Waste	147,600 gal
Wash water	4,271 gal
Solids	1,037,000 lb
Slurry volume	211,275 gal
Total volume injected	217,468 gal
Activity	4099 curies Ce
	193 curies Cs
	608 curies Sr
	35 curies Ru
	4 curies Co

Injection 6A

Date	May 19, 1965
Depth	880 ft
Liquids	
Waste	4,400 gal
Wash water	18,800 gal
Solids	16,700 lb
Slurry volume	5,670 gal
Total volume injected	24,470 gal
Activity	Combined with 6B

Injection 6B

Date	May 22, 1965
Depth	872 ft
Liquids	
Waste	64,000 gal
Water to overdisplace	4,000 gal
Solids	About 384,000 lb
Slurry volume	92,800 gal
Total volume injected	96,800 gal
Activity (includes 6A)	1562 curies Cs
	330 curies Sr
	2 curies Ru
	1 curie Co

Injection 7

Date	Aug. 16, 1965
Depth	872 ft
Liquids	
Waste and water	85,000 gal
Water to overdisplace	1,550 gal
Solids	587,760 lb
Slurry volume	123,411 gal
Total volume injected	124,961 gal
Activity	3358 curies Cs
	492 curies Sr
	2 curies Ru
	14 curies Co

Injection ILW-1A

Date	Dec. 12, 1966
Depth	872 ft
Liquids	
Waste	37,440 gal
Water	2,791 gal
Solids	250,000 lb
Slurry volume	55,000 gal
Total volume injected	57,791 gal
Activity	11,500 curies Cs
	41 curies Sr
	1 curie Ru
	16 curies Co
	20 curies Ce

Injection ILW-1B

Date	Dec. 13, 1966
Depth	872 ft
Liquids	
Waste	26,000 gal
Water	3,700 gal
Solids	184,000 lb
Slurry volume	40,197 gal
Total volume injected	40,197 gal
Activity	7,600 curies Cs
	38 curies Sr
	8 curies Ru
	3 curies Co
	13 curies Ce

ILW-2A

Date	Apr. 20, 1967
Depth	862 ft
Liquids	
Water	2,000 gal
Waste	81,400 gal
Solids	500,000 lb
Slurry volume	121,805 gal
Total volume injected	121,805 gal
Activity	31,329 curies Cs
	564 curies Sr
	99 curies Ru
	236 curies Co

ILW-2B

Date	Apr. 24, 1967
Depth	862 ft
Liquids	
Waste	64,345 gal
Water to use up solids	15,455 gal
Solids	515,000 lb
Slurry volume	108,600 gal
Total volume injected	108,600 gal
Activity	26,350 curies Cs
	474 curies Sr
	199 curies Co
	83 curies Ru