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TECHNICAL ASSESSMENT MASSIVE FOAM STIMULATION ATTEMPT IN MERCER CO., PA.
--- The Peoples Gas Company Well No. 4978

By

K-H FROHNE

November 1978

UNITED STATES DEPARTMENT OF ENERGY
Morgantown Energy Technology Center
Morgantown, West Virginia

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MASSIVE FOAM STIMULATION ATTEMPT IN MERCER CO., PA

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ABSTRACT

This report provides an assessment of a large scale foam fracturing test performed by the Peoples Gas Company in cooperation with the Energy Research and Development Administration (now the Department of Energy) in Mercer County, PA. The test was designed to evaluate gas productivity of the Devonian Shale in a currently non-producing area, and was to utilize 270,000 gallons of nitrogen/water foam as the fracturing fluid and 324,000 pounds of sand proppant in a massive stimulation attempt.

Unexpectedly high treating pressures encountered during the frac job as well as a mechanical packer problem caused a catastrophic downhole casing failure and the stimulation test could not be completed. The report describes the aborted foam fracturing operation and its aftermath. After extensive remedial efforts, the well was plugged and abandoned, but the Devonian Shale, despite the stimulation failure, produced some evidence of free gas in place.

INTRODUCTION

The Eastern Gas Shales Project (EGSP) managed for the Department of Energy by the Morgantown Energy Technology Center (METC) is engaged in a major effort to define the natural gas resource base and production potential of the Devonian Shales of the Appalachian Basin. As a part of this research effort, the EGSP is conducting field tests to determine the effectiveness of various explosive and hydraulic stimulation treatments on gas productivity from the Shale. One of these field tests proposed a large scale foam fracturing test for an existing non-commercial gas well completed in the Medina Sand, The Peoples Gas Company's well No. 4978 in Mercer County, PA.

This report details the treatment design and field execution of the foam frac, as well as mechanical problems that curtailed the planned stimulation.

STIMULATION RESEARCH PROGRAM

Background

The stimulation test described in this report resulted from an unsolicited proposal submitted to METC by The Peoples Natural Gas Company (PNG), in which they proposed to fracture the Devonian Shale interval in Mercer County, PA. The proposed test well, PNG No. 4978 on the J.E. Fleck lease (State Permit No. MER-20176), was located in an area of the Appalachian basin where the Devonian Shale had not been tested for gas productivity, the nearest Shale tests being 40 miles to the north and 45 miles to the south, and so fit into the EGSP regional research pattern.

The well originally had been drilled to granite at 9247 feet as a basement test on a seismic anomaly, but was then completed in the Medina sandstone perforated from 4990-5040 feet. After stimulation, the well proved to be non-commercial due to low productivity and distance from a pipeline, and the well was shut in pending further development.

A complete suite of electrical logs run from TD to surface at the time of drilling showed the Middle Devonian Shales between 3100 and 3400 feet to have fairly high hydrocarbon content as well as some secondary porosity. This made the Shale a potential prospect as a dual completion zone to supplement the Medina delivery rate to possibly justify a pipeline connection.

With this background, PNG submitted a proposal to METC to conduct a massive foam fracturing test on the Devonian Shale interval to test that zone for gas production, and to possibly meet economic pipeline requirements to permit production of both Medina and Shale intervals. The proposal dovetailed into the EGSP stimulation research program and was accepted as a cost-sharing research project.

Well Location

The PNG no. 4978 well is located on the J.E. Fleck lease west of the village of Sheakleyville in Mercer Co., PA, 15 miles north of the county seat, the town of Mercer. Figure 1 shows the well location.

Stimulation Treatment Design Considerations

Based on hydrocarbon indications on the log suite, the Devonian Shale was perforated with 50 holes over the interval 3112-3360 feet. The well had been prepared for the stimulation by setting a bridge plug in the 4 1/2 inch production casing at 4600 feet, cutting the casing at 4400 feet and pulling it out in the well. After squeeze-cementing the 8 5/8 inch protection casing from 3440 feet to 2800 feet a retrievable bridge plug was set in the 8 5/8 inch casing at 3416 feet. The 4 1/2 pipe was then rerun with a frac packer to 3100 feet, just above the perforated Shale interval. Figure 2 shows a schematic of the wellbore, including casing strings and Medina and Shale completion intervals.

Little natural fracturing had been indicated during drilling of the Shale, and a massive scale stimulation was planned for the well in order to create a large surface area fracture. Massive hydraulic fracturing can be defined as injection of at least 1000 gallons of frac fluid per foot of stimulation interval, and on this basis PNG proposed a 270,000 gallon foam frac. Nitrogen/water foam was chosen as frac fluid because of its good clean-up performance in low pressure formations as well as its low water content and resulting reduced water exposure to the clay-containing Shale.

The job required a large amount of materials and equipment, including an estimated 2900 MSCF of nitrogen gas, 54,000 gallons of fresh water, 324,000 pounds of sand, various chemical additives, and 12 major pieces of frac equipment. The nitrogen volume requirement was based on an estimated formation treating pressure of 1500 psi, a formation temperature of 75°F, and a desired foam quality of 80, i.e. a frac fluid containing 80 percent nitrogen gas by volume and 20 percent water with additives. Table 1 gives a detailed listing of materials, and Figure 3 shows a schematic of fracturing equipment as assembled at the well site.

In addition to nitrogen and water, six gallons of surfactant, one gallon clay stabilizer, and 44 pounds of calcium chloride per 1000 gallons of water were injected with the foam. The job design also included 2000 pounds of flaked benzoic acid to be used as a temporary diverting agent to insure that the entire perforated interval accepted some fracturing fluid.

Foam Fracturing Operation

The cable tool workover rig that had prepared the well for the Devonian Shale test remained over the well during the fracturing and later remedial activities. Two days before the foam frac, the perforated interval was broken down with 1000 gallons of 15 percent HCl acid and then balled out with 40 perf balls and a further 4000 gallons HCl to insure that all of perforations were open to accept frac fluid. The next day, the spent acid was swabbed out by the service rig, and the well was ready to be stimulated.

The foam frac operation was started the following morning by pumping 1000 gallons of 15 percent HCl acid solution as a spearhead followed by a 1750 gallon pad of 80 quality foam. The pad injection pressure (surface reading) started out at 2610 psi and rose to 2900 psi. Pad pumping rate was about 12 barrels per minute (BPM) foam.

Following the pad, the foam pumping rate was increased to approximately 22 BPM to carry 19,700 pounds of 80/100 mesh sand, first at 3/4 pound per gallon (PPG) foam concentration and then at 1 PPG. Pumping pressure during the 80/100 mesh sand stage climbed from an initial 2950 psi to 3100 psi at stage end.

Sand was changed over to 20/40 mesh at a concentration of 1/2 PPG, and pressure climbed to 3190 psi. Sand concentration was increased to 1 PPG and then to 1 1/2 PPG as pumping pressure continued to climb very slowly. Pumping rates were maintained at close to 20 BPM.

After 70,000 pounds of 20/40 mesh sand had been pumped away, 93 minutes into the foam frac job, a sudden mechanical failure occurred downhole. Pumping pressure immediately fell, pumps were shut down, and a short time later, sand-laden foam erupted from a short 2 inch flowline and valve on the 8 5/8 inch casing head. The valve and flowline were fortunately located on the wellhead side away from spectator and frac equipment areas, and the stream was venting across an open field and into a wooded area.

After flowing at high rates for a few minutes, the sand in the foam eroded the valve inlet nipple and a tremendous burst of nitrogen, water, and sand sprayed from the side of the casing head. The stream quickly stripped away the back side of the service rig as spectators and frac personnel rapidly evacuated the well site to watch events from a safer distance. During the curtailed foam frac operation, 1,582,000 SCF of nitrogen gas, 18,500 gallons of water, and 89,700 pounds of sand had been pumped into the well, most of which then rapidly escaped from the fractured interval and returned to the surface.

TABLE 1 - FOAM FRAC MATERIALS

Materials	Design Quantity	Actual Quantities Used
Water	54,000 gallons	18,500 gallons
Nitrogen	2,900,000 SCF	1,582,000 SCF
Sand, 80/100 mesh	44,000 pounds	19,700 pounds
Sand, 20/40 mesh	280,000 pounds	70,000 pounds
Surfactant foaming agent	400 gallons	112 gallons
Clay stabilizer	40 gallons	14 gallons
Calcium chloride	3,000 pounds	815 pounds
Benzoic acid, flaked	2,000 pounds	0 pounds
Hydrochloric acid, 15 percent	1,000 gallons	1,000 gallons

The well continued to flow for some time until the injected nitrogen was depleted and the well died back to a slight flow of dry gas. Well head and service rig damage was actually slight in view of the energy expended, and the rig was quickly put back into operating condition with hammer, crowbar, and winch cable.

During the flowback, an unknown but substantial amount of sand proppant was sprayed over the back side of the well location. Trees about 30 to 50 yards away had coats of sand plastered on trunks and branches, and there was a solid layer of sand over the rear quadrant of the well site. This served to illustrate the potential hazards associated with any stimulation effort, as well as the need for good wellhead arrangement and spectator control.

Well Remedial Efforts

As soon as the service rig was fully repaired, attempts were made to unseat and retrieve the 4 1/2 inch casing packer, but the rig crew was unsuccessful in freeing the tool. A logging contractor then ran a cased hole survey to determine the downhole situation, running Gamma Ray, collar locator, cement top, and Spinner flowmeter surveys over the lower part of the well. Interpretation of the logs indicated no splits or holes in the 4 1/2 inch pipe, but about 65 feet of sand fill in 4 1/2 - 8 5/8 casing annulus above the 4 1/2 inch packer. The Shale perforation interval below the packer was sand-free and open. The Spinner survey showed some gas entry into the water-filled borehole, but the flow rate was too low to measure at the surface. However, this was a positive indication of free gas in place in the Shale, and demonstrated some production potential in this previously untested area. Figure 4 shows a schematic of the wellbore after the stimulation attempt and later remedial efforts.

After the log evaluation a ball was dropped into the packer to seal off the 4 1/2 inch pipe, which was then perforated just above the packer at 3097-99 feet in order to establish communication between the 4 1/2 and 8 5/8 inch casing strings. A service company pumper was then used to circulate clear water through the 4 1/2 - 8 5/8 annulus to flush out the log-indicated sand fill. However, only a very small amount of sand and some foamy water was recovered from the annulus. A slug of gelled water was circulated around but no more sand or debris was recovered. At this time, field personnel on the site thought that possibly a hole existed in the 4 1/2 inch pipe just above the indicated sand fill, although the log suite had indicated the pipe string to be sound.

Another attempt was made to pull the packer with the rig, and this time the tool broke free; possibly the hole circulation has had some beneficial effect. About 50 feet of pipe were recovered before the packer stuck solidly again at 3048 feet. Hydraulic jacks were rigged to exert a stronger pull than the service rig could deliver, but the packer could not be moved further up the hole. At this time, it was thought that the packer was completely sanded in place in the 8 5/8 inch pipe.

The 4 1/2 inch frac pipe was then explosively cut just above the packer and the rig was able to pull the entire string. The last few pipe joints were badly scratched and dented on the outside, which indicated collapse of the 8 5/8 inch casing. Casing collar and caliper logs were run and confirmed internal damage to the 8 5/8 between 2960 and 2985 feet as well as sand or debris hole fillup to 3043 feet, just above the packer.

The log evidence when taken with the frac fluid flowback and the scratched and dented 4 1/2 inch pipe clearly pointed to a pressure collapse and a resulting split in the 8 5/8 just above the original packer seat. Evidently some high pressure frac fluid had either channeled through the 8 5/8 cement sheath or through the formation above the perforated interval, and had collapsed the internally unsupported casing above the frac packer.

In view of the mechanical problems, collapsed casing, casing packer jammed below the damaged section, and no indications of substantial gas production from the Devonian Shale interval, PNG made a decision to stop further remedial work and to permanently plug and abandon the PNG No. 4978 well.

CONCLUSIONS

Several conclusions can be drawn from the foam frac test attempted in the Devonian Shale of Mercer County, PA. The test showed that the Shale in this area of low natural fracture density is mechanically strong and requires high fracture treating pressures, more than twice as high as predicted on the basis of Shale behavior in producing areas. The high pumping pressure in turn greatly increased the nitrogen gas required per gallon of foam and thus the economic cost of foam fracturing. The field test results demonstrated that a formation breakdown test to determine fracturing pressures should be run in untested areas before the stimulation designs are finalized and frac fluids and proppants are assembled at the well site. If practical, flexibility of job design selection should be maintained until treating pressures can be accurately predicted, specially when considering compressible frac fluids like foam.

The collapse of the 8 5/8 inch casing above the perforated interval, as indicated by log survey and other evidence, was probably caused by high frac fluid pressure acting directly on the outside of the casing just above the frac packer. Above the packer seat, the 8 5/8 annulus was partially water-filled but open to the atmosphere at the casing head, and an external pressure differential of more than 2000 psi on the casing could have caused the collapse and the resulting split connecting the fracture zone with the annulus.

The induced fracture only had to extend vertically 15 feet above the top perforation to reach above the packer set point, and this amount of vertical extension is not unusual in shale at 20 BPM pumping rates. In situations where frac pipe and packer arrangements are used, the potential for collapse failure could be minimized by setting the packer 100 to 200 feet above the perforated interval. This should place the packer safely above vertical fracture extension and the associated external pressure differential acting on the casing. It is, of course, imperative to have good cement bond between casing and formation to prevent fluid channeling up the hole.

Finally, although the stimulation attempt was a mechanical failure, the test proved that the Devonian Shale in this currently undeveloped area of the Appalachian Basin does contain free gas in place, as evidenced by the limited gas influx during remedial operations. Taken together with the electric log-derived porosity and hydrocarbons in place, this small gas show demonstrates that the Shale is still a good potential gas prospect in Mercer County.

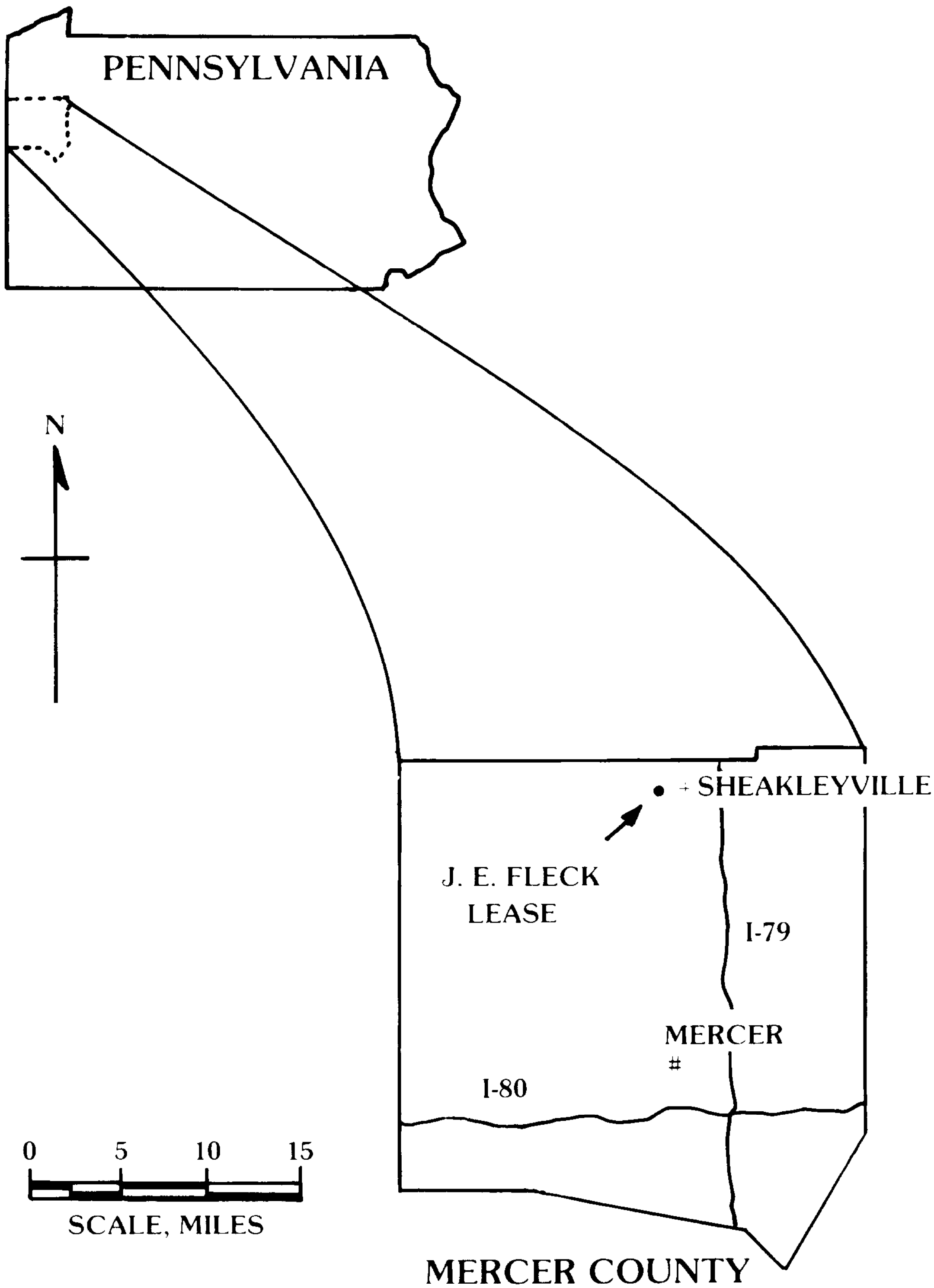

FIGURE 1

WELL LOCATION - PNG NO. 4978 (J.E. FLECK NO. 1)

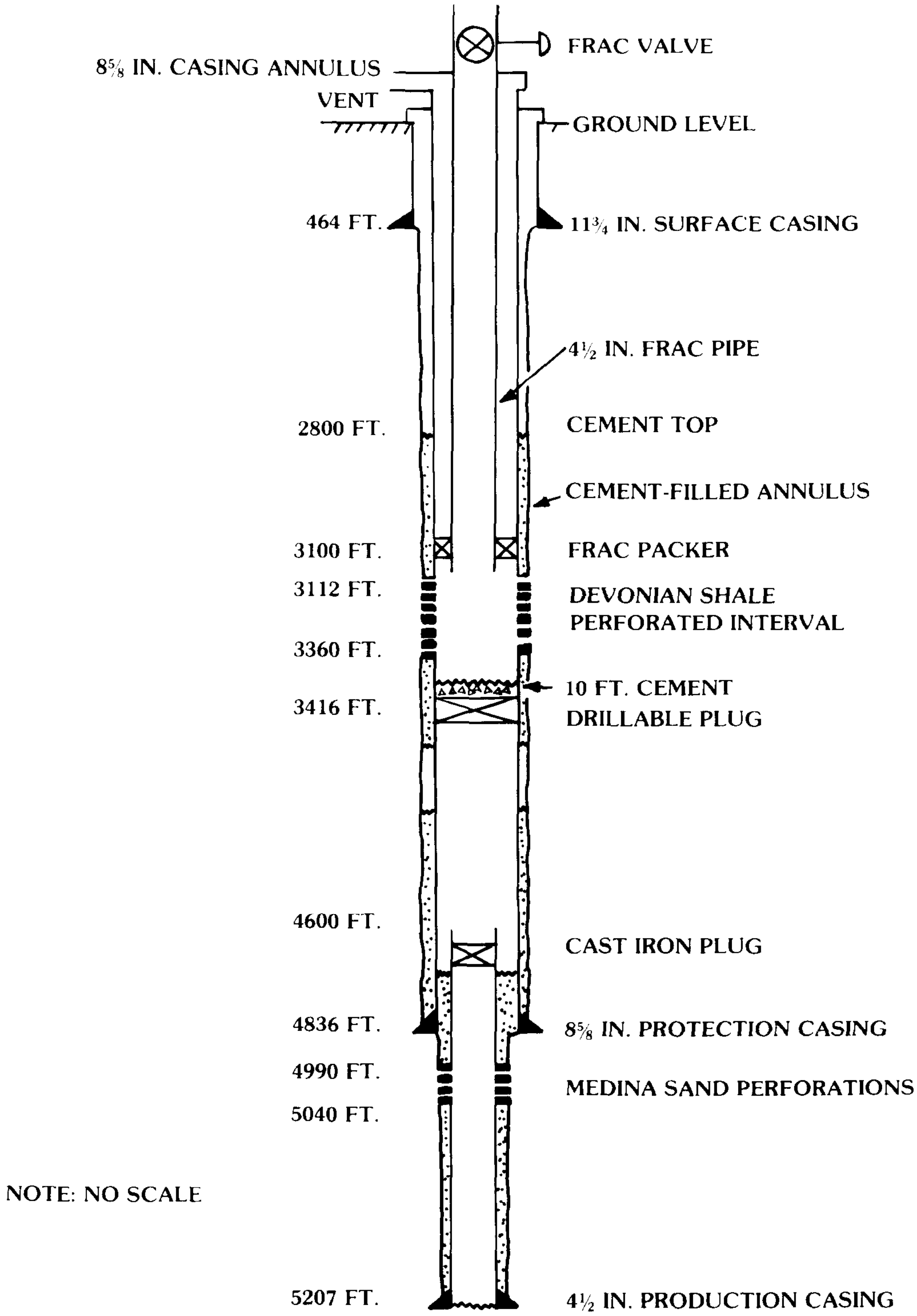

FIGURE 2

WELLBORE SCHEMATIC

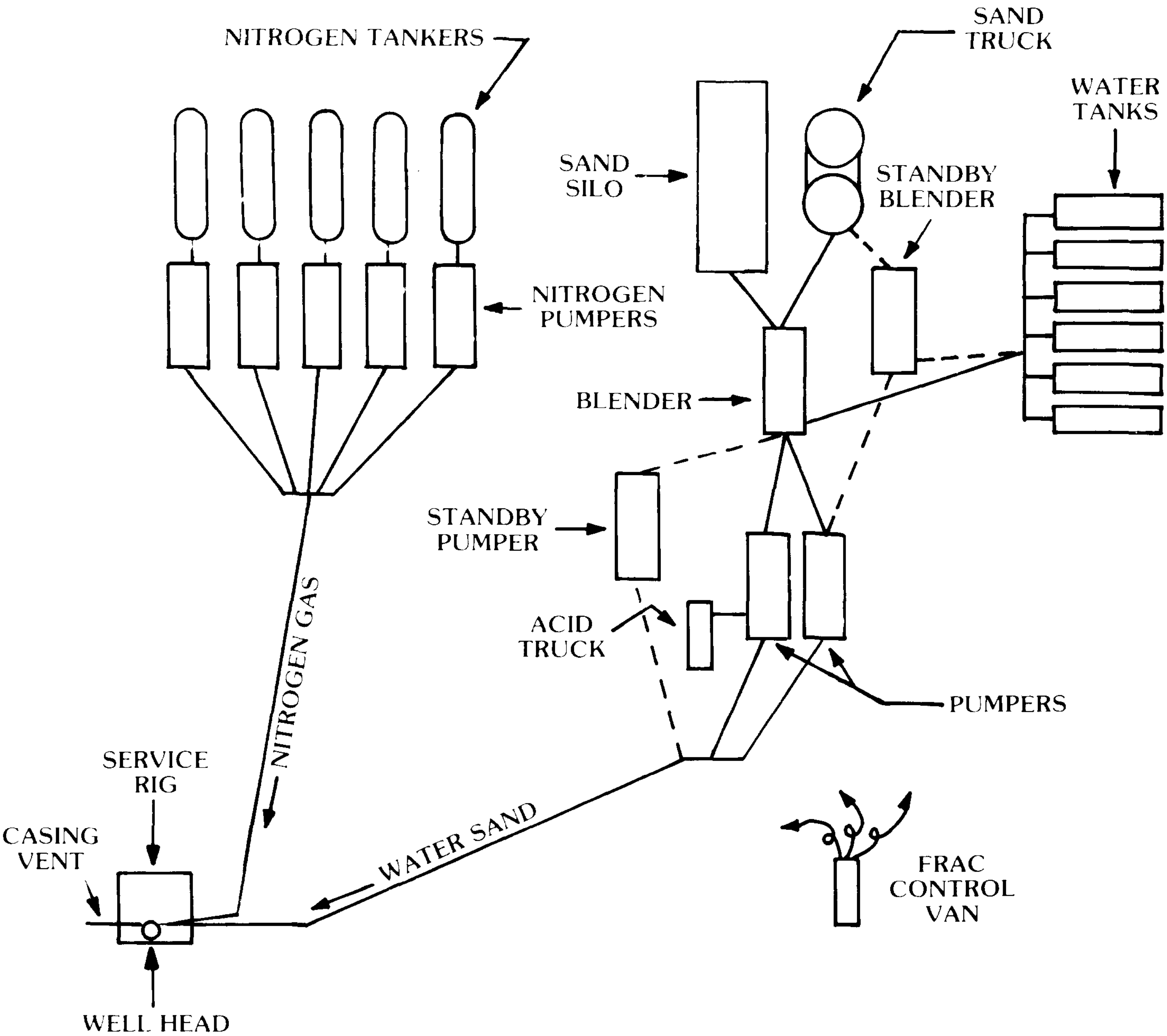

FIGURE 3

FOAM FRACTURING EQUIPMENT LAYOUT

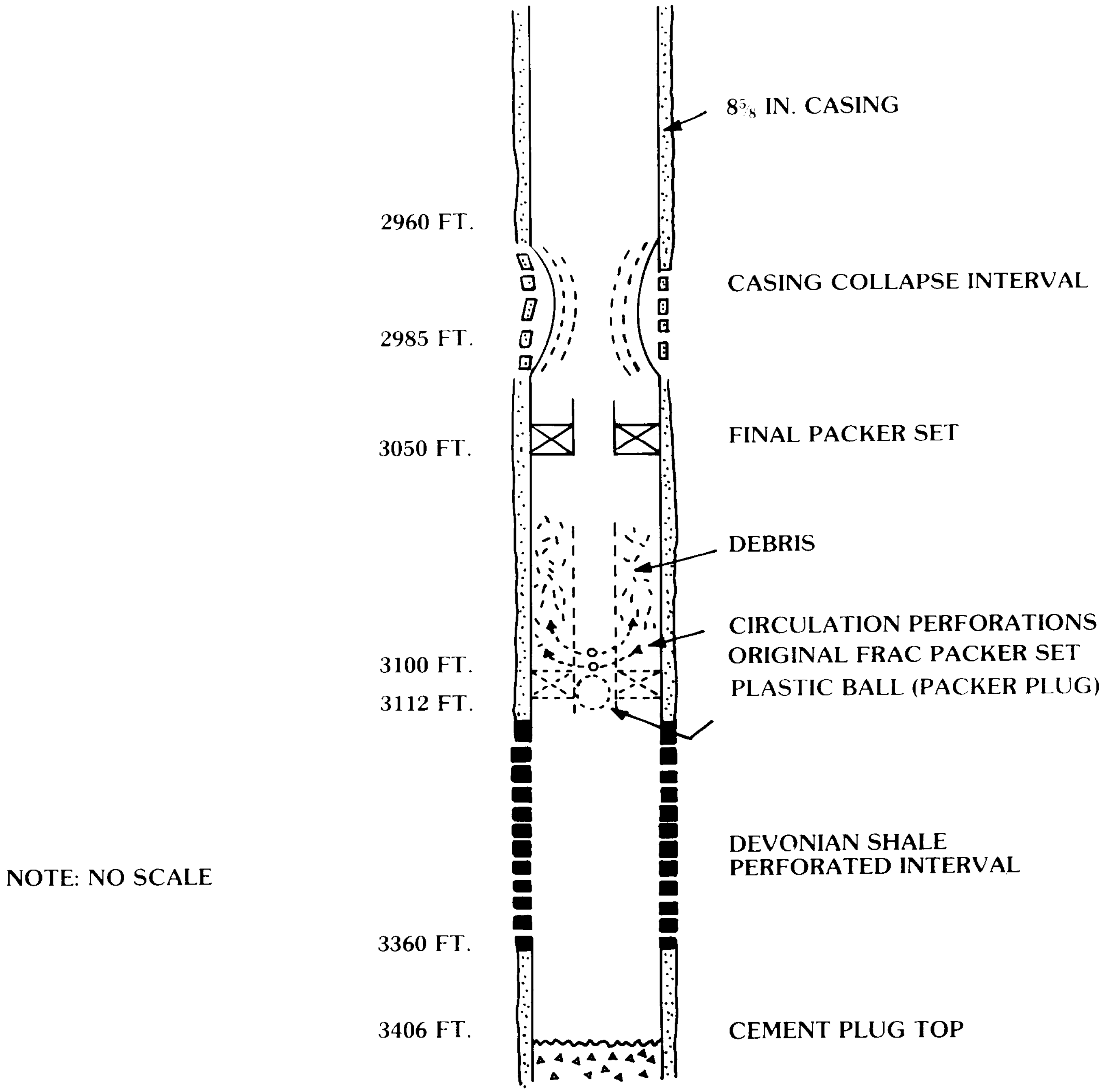

FIGURE 4

POST FRACTURING WELLBORE SCHEMATIC