Methods of Joining Two or More Wells for Brine Production

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ABSTRACT

Three methods are currently used to join two wells for brining operations: coalescence, hydrocarbon pads, and fracturing. In this paper, I have made operational and cost comparisons among these methods.

Of these techniques, fracturing is the least expensive but possibly the most complex. The main problem is how to determine the development of fracture patterns so that costs do not become excessive. To show examples of the problem, I have presented nine case histories, based on information from specific jobs, with my evaluations of the situations.

INTRODUCTION

The practice of injecting water into one well and producing brine from a connecting well is not new. Producers have long recognized the efficiency of such production over the one-well method in bedded salt. Prior to mid-1950, coalescence was used for joining, but subsequently two other methods have also been developed:

1. Hydrocarbon Pads
2. Fracturing

Of these three joining techniques, fracturing can be the least expensive; however, many problems can arise to increase the costs. The main problem is how to determine the development of fracturing patterns so that excessive costs can be avoided. Some specialists believe that almost all induced fractures are vertical. Others believe that the induced fracture will follow the pattern of natural fractures. Still others believe that fractures remain horizontal. Fracture patterns, however, are governed by the rock and associated conditions in which they develop and do not conform to a standard rule. I have examined nine case histories to show some possible fracturing patterns and have offered my hypotheses of the situations that developed. By this discussion I hope to provide some insight into possible problems connected with this technique.

THREE JOINING METHODS

Coalescence

Coalescence between two or more wells to produce brine was a natural development. As single systems were worked, they eventually coalesced. Brine was then produced by injecting water into one well and producing brine from the other. Selection of the injection well and the producing well was usually based on surface conditions, and downhole conditions were not considered.

The advantage of this method over the one-well system was the reduced brine production cost. However, several disadvantages developed:

1. Expensive workovers are required to keep a dip tube on the bottom.
2. Overworking the wells is inherent in this method. This overworking creates indiscriminate cavity fingering from each well until two fingers intersect to join the wells.
3. This indiscriminant fingering is an inefficient use of the land and can result in future problems. Uncontrolled dissolving by two wells can take up valuable space that could have contained more wells if the method of joining them had been controlled. This is becoming an increasing problem as possible brine field space is being closed off by the spread of cities. It also results in need for more land to maintain product at a time when land costs are rapidly increasing.

Hydrocarbon pads

In this method, an oil pad is placed in each well close to the bottom of the salt (Fig. 1). This controls the level of the top of the cavities the water is being pumped in.

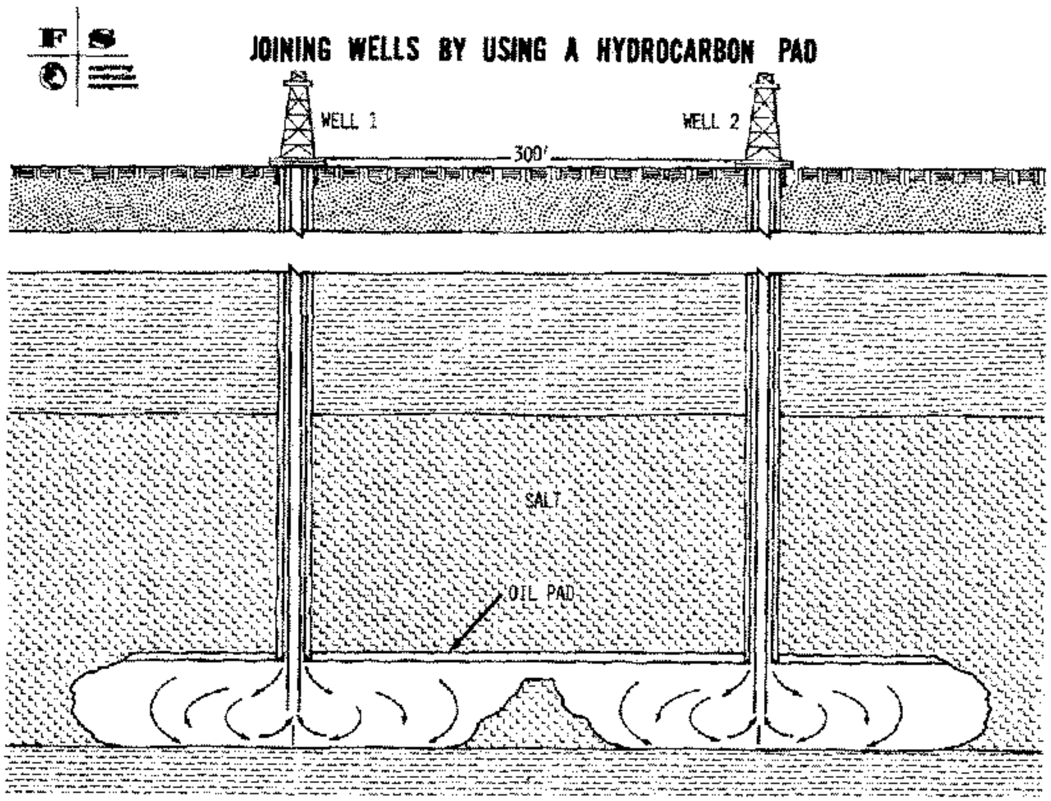

Figure 1.

Well spacing of 300 ft or less is recommended, and 18 months is the average amount of time needed to join the wells.

The advantages of this technique are:

1. With proper production techniques, the brine field can be developed with maximum property utility.

2. Cavity development can be controlled by this method, leading to a more symmetrical cavity shape. Such a cavity is a potential underground facility that can be used later for storage of hydrocarbons or plant wastes.

The disadvantages include the following:

1. The padded cavity structurally weakens the producing well, thereby creating a situation that causes loss of saturation. The uphole casing can eventually separate, allowing undersaturated brine to enter the casing of the producing well. If this separation is vertical only, the repair is quick and can be made at low cost. However, if the formation moves laterally, the workover is complicated and expensive.

2. The cavities are so close together that they combine to form one large cavity, causing an increase in workover costs to keep a dip tube on bottom.

Fracturing

This technique has been widely discussed in recent years and will not be detailed here. However, I have listed several job case histories and what is known about their fracturing patterns in an attempt to hypothesize the unknown portion of the fracture pattern. For example, when a connection is achieved, the fracture pattern can be ascertained with some certainty because the ends of the fracture are known. When a connection is not achieved and only one end of the fracture is known, the problem of tracing a pattern becomes more difficult.

When a fracture does not connect wells as planned, the engineer in charge must determine as closely as possible what happened and how to correct the situation. Although he has some devices that can help him make a diagnosis, his most important tool is his own knowledge and experience. In the following case histories, I have presented my conclusions about the direction of the fracture patterns as possible explanations for similar developments.

Case 1

Fact. A well was fractured in 10 ft of open hole with casing set about 15 feet off of the bottom of the salt. A fracture connection was made to the target well in 6 hours. A caliper survey identified the entry point of the fluid into the target hole at 200 ft above the bottom of the salt. Because the fracture had to pass through a large section of insoluble material to come out that high up, it was believed that a low pressure connection might never be accomplished or at least considerable time and cost would be required to erode the insoluble section. A decision was made to fracture back from the target hole to the original fracturing well. A hydraulically inflated packer was set in the target hole at the same level as the pipe was set in the original fracturing hole. The fracture attempt was made and a connection accomplished in 2 hours. A low pressure connection was completed in 7 1/2 hours.

Hypothesis. When the fracture was initiated, it started out on the interface selected because of its good fracture extending capabilities. The fracture went some distance on this plane. It finally intersected a natural fracture and started up through the insoluble section to the next salt section above and from there wandered indiscriminately up through the section to the next clean interface. Again it spread out until it found another natural upward fracture. The process was repeated until the spreading finally included the target hole. Injection was reversed, but no returns came out of the original fracture point 190 ft below. When the injection was again made from the first well, returns could be obtained from the target hole.

It seems safe to assume that the natural fractures also guided the induced fracture on up into zones above the point of entry into the target hole. The higher a fracture goes, the smaller amount of overburden it has, hence less pressure. Therefore, the highest fracture section would be the route of least resistance. So when liquid was injected into the upper end of the fracture, the fluid followed the higher section of the fracture rather than the fracture connection to the first well (see Fig. 2 for illustration of this hypothesis).[1]

Case 2

Fact. Figure 3 shows the results of two neutron log runs of a bedded salt well. The solid line indicates the original log. The fracture was initiated approximately 90 ft below the section shown. Millions of gallons of fresh water were injected into both wells without making a connection; then a second neutron log was run. The dashed line indicates the difference in the two logs.

Hypothesis. The fractures apparently were indiscriminate and actually the wells were joined prior to the running of the second log. This was concealed because the casing in the target well prevented the fluid from entering the target hole. Certainly the fracture did not remain on the same level as it started.

Case 3

Fact. Three wells had been drilled in a straight line. A fracture attempt was made from well 1 to well 2; however,

1. All sketches are illustrative; they are not representative of true salt sections.

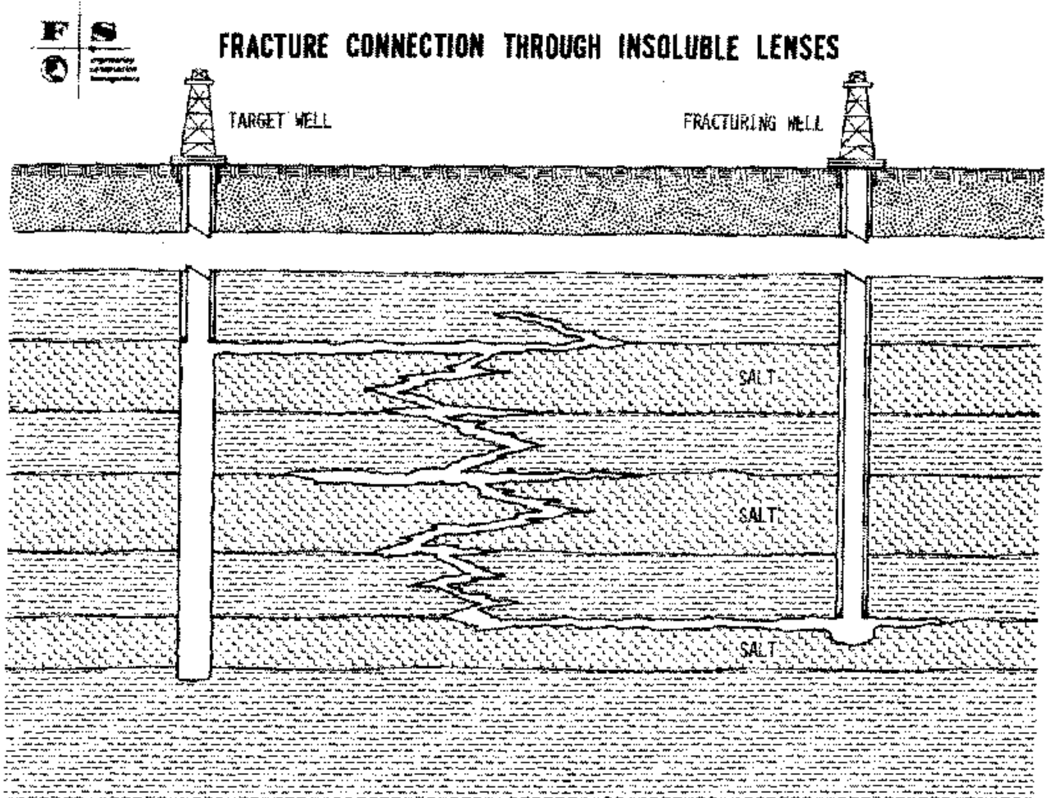

Figure 2.

COMPARISON OF NEUTRON LOGS RUN BEFORE AND AFTER FRACTURING

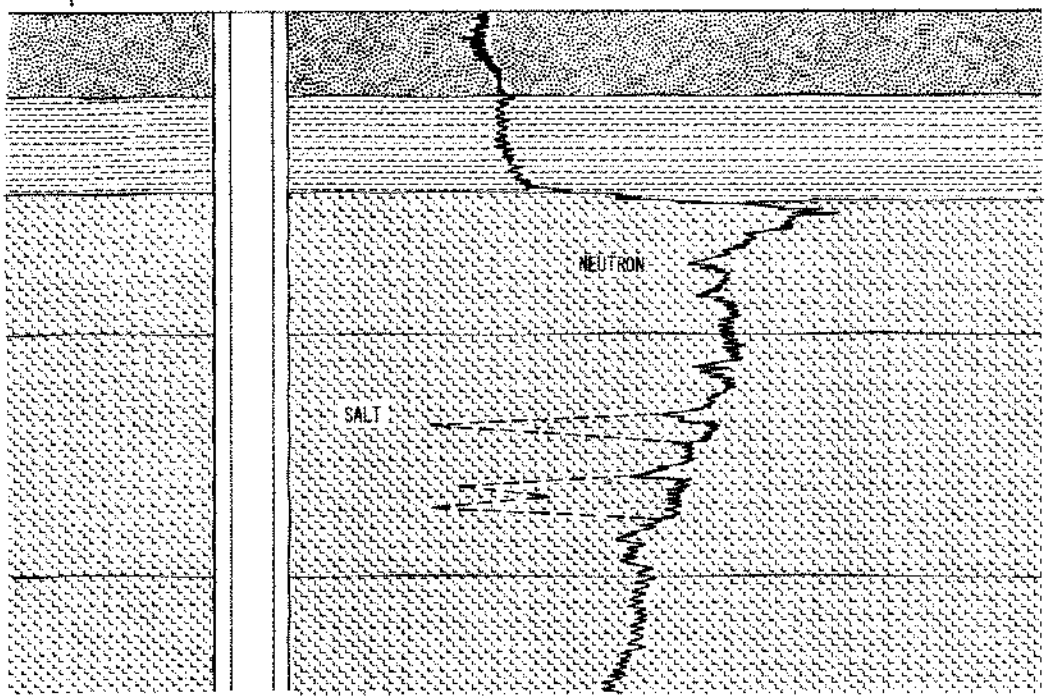

Figure 3.

connection was made with well 3, bypassing 2, in about 4 1/2 hours. Because well 3 was already connected to another well, it was not a desirable target. More water was injected into well 1. In a short time the water broke into well 2 and a 1–2 system was established. A low pressure connection to well 3 never had a chance to develop, thus keeping independent systems.

Hypothesis. A horizontal fracture was apparently created from well 1 to well 3, about 3 ft below the bottom of well 2 (Fig. 4), and subsequent water injected at well 1 dissolved a cavity upward to connect with well 2.

Case 4

Fact. Two wells were to be connected by fracture, with millions of gallons of water being injected into each well. However, no connection was obtained. Further examination indicated a good fracture plane for a second fracturing attempt at the indicated perforating point shown in Figure 5. Both wells were perforated at this level. A bridge plug was placed below the perforated point in well 2, the fracturing well. When the well was fractured, the breaking pressure indicated a bad cement job. In about 20 minutes a connection was made with well 1, and a low pressure connection was made in 2 hours. Fluid entered well 1 at the old original fracture point at the bottom of the salt, not at the new perforations above in well 1.

Hypothesis. During the original fracturing, a connection was made from well 1 to well 2 behind the pipe. The subsequent fracture made several months later and at the higher level from well 2 to well 1 went down the outside of the pipe, through a bad cement job, and connected with the old fracture about 20 ft below the perforations. Perhaps if a neutron log had been run in well 2 after the first fracture attempt, the fracture behind the pipe would have been discovered. This would have shown that connection could be made simply by perforating well 2.

Case 5

Fact. A fracture attempt made a connection between two wells in 1 hour, and in less than 2 hours the target well was flowing over 100 gpm. This flow then started declining until it stopped completely. A caliper survey in the target hole showed a definite decrease in hole size at the point of fracture entry.

Hypothesis. A pressure drop always occurs as the brine enters the well bore from the fracture. In this case, this pressure drop caused a precipitate to form, covering the fracture entry point and eventually sealing off the fracture.

Case 6

Fact. Several fracture connections have been made with old systems and/or wells some distance away from the injection wells in a relatively short time. One example of such a connection was made in 5 minutes, and a low pressure connection was made in less than 1 hour.

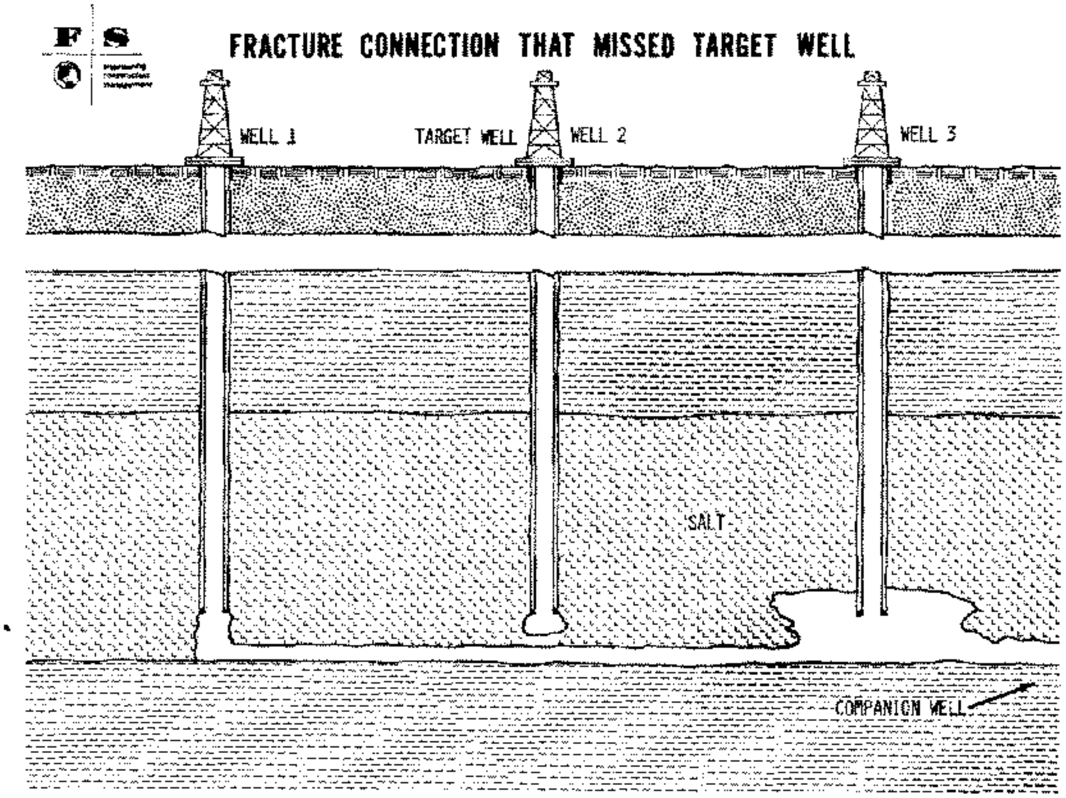

Figure 4.

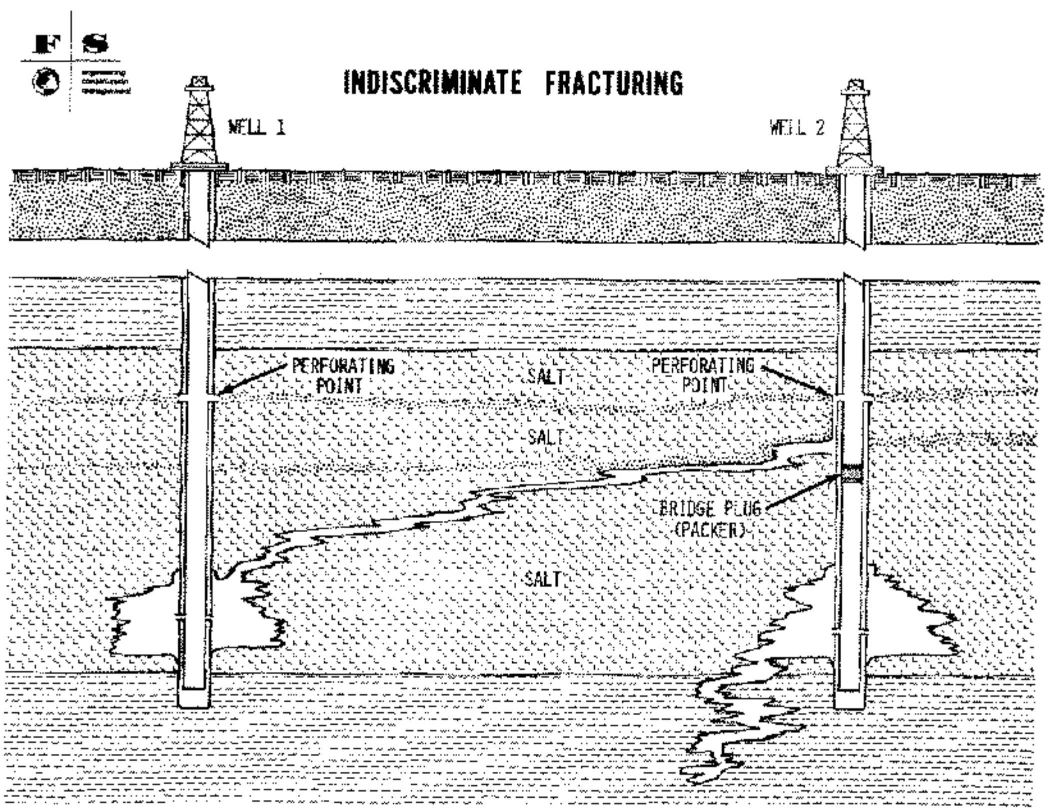

Figure 5.

Hypothesis. I feel that such connections are made by intersecting old, dormant fractures created when the old well or system was fractured. Therefore, the new fracture did not reach the old system, it just connected with an old fracture originating from the old system.

Case 7

Fact. A well was fractured and connected with the target well about 550 ft away in approximately 1 hour. Water was started in the pumping well. However, the connection was ultimately lost. The well was eventually made into a one-well system by using an oil pad.

Several years later a sonar caliper was run on the well and revealed an elongated cavity (Fig. 6). The fracture well's borehole was about 10 ft from one end of the cavity and the other end was about 75 ft from the borehole, pointing toward the original target hole.

Hypothesis. One explanation that has been offered is that dip was responsible for the lopsided cavity. After the fracture attempt failed, an oil pad was used with success. An oil pad, when properly used, will remove all dip influences on a solution mined cavity. This area, however, has a natural local dip of approximately 1/2°, and to develop a lopsided cavity like this would require a minimum dip of 15° to 20°.

The explanation that seems to best fit the situation is that a horizontal fracture ruptured out one side of the hole and extended into the salt. When water was introduced, it followed the fracture, causing the cavity to develop preferentially in the direction of the original fracture.

Case 8

Fact. Several wells on which fracture attempts were made years ago have recently been joined and, surprisingly, at a lower pressure than was originally encountered. In each case substantial amounts of water had been injected into the wells either during the original fracture attempt or during the operation of the one-well system.

Hypothesis. The cavities created around each well apparently caused a flow of the salt toward the center of the nearest cavity, developing a low pressure zone around each well. As time passed these two low pressure zones joined. Thus, when pressure was applied to one well, it followed the path of least resistance to the other well. The main problem with this type of development, however, is the level at which any two wells join. If it is above the bottom of the salt, this will be a significant factor in the future cost of operation.

Case 9

Fact. A fracture attempt was made from a new well to an old system that had been in operation 40 months. The connection was made in 10 hours. A low pressure connection was established several weeks later.

Hypothesis. This slow development of a low pressure connection was the result of condition changes between the time the old system was initiated and the fracturing

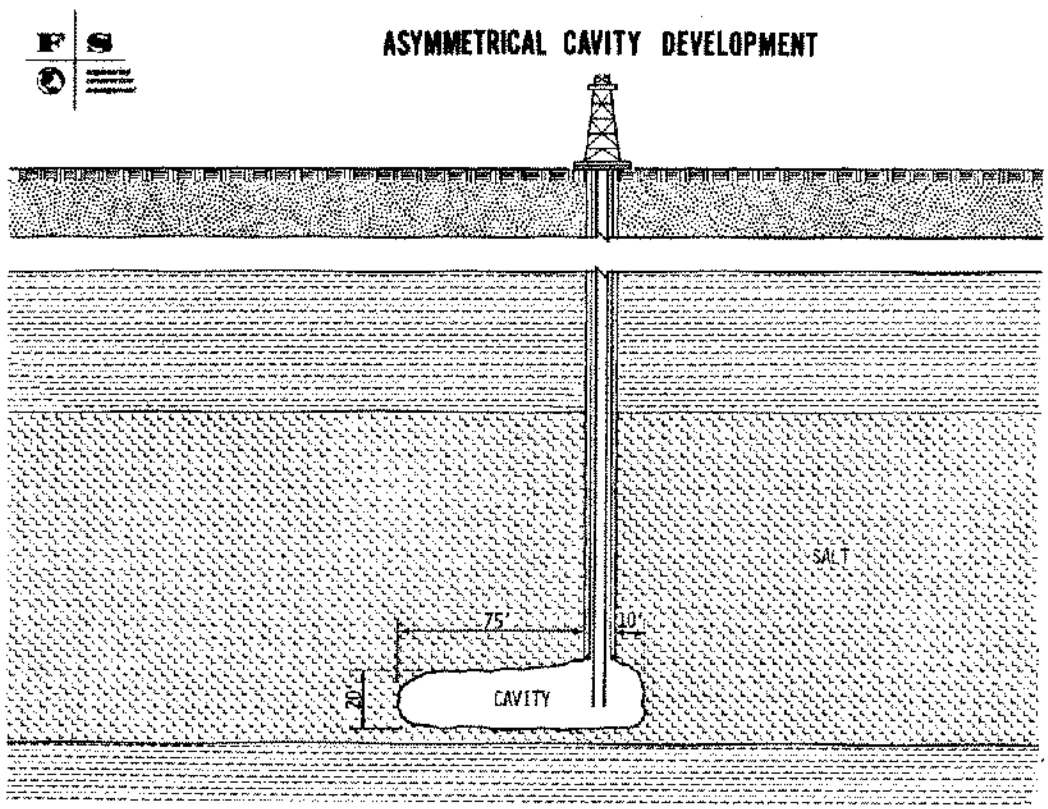

Figure 6.

TABLE I

Comparative Data on Raising Salt by Different Methods

General Assumptions

Well Depths:	Approx. 3,000 ft.	Capital Costs:	21% of Total Cost
Well Costs:	Well 1–$41,250 Well 2–$46,500	Power Costs:	Not included because of variance from area and plant to plant
System Production:	1,500,000 tons		

Special Assumptions

Life and production data.

Method of Operation	Life Prior to Coalescence (years)	Production Prior to Joining (tons)	Life After Coalescence[1] (years)
Coalescence	3	235,000	13
Padding	1 1/2	80,000	11
Fracturing	None	None	9

Cost of well construction and operation prior to joining.

Method of Operation	Well and Special Equipment Costs	Cost of Operation per Year Prior to Coalescence	Total Costs
Coalescence	$ 82,500	$25,000	$157,500
Padding	102,500	35,000	155,000
Fracturing	131,500[2]	50,000	181,500

Production costs of salt.

Method of Operation	Capital Costs	Operational Costs	Total Costs	Cost/Ton/Year[3]
Coalescence	$33,075	$20,000	$53,075	54.5¢
Padding	32,550	15,000	47,550	36.8
Fracturing	38,115	3,000	41,115	24.7

[1] Cavity operation 50 percent of time.

[2] Three wells have been included, anticipating 1/3 of wells will fail to connect.

[3] Lifting costs not included.

attempt was made. When a cavity is created, nature will attempt to heal itself, and salt will start flowing from all directions toward the cavity. This will in turn change the rock mechanics properties of the area. Experience and studies so carefully used to create procedures for fracturing in the area, therefore, no longer apply, and a whole new set of ever changing rules must be discovered and applied to any new fracture attempt.

The rock mechanics properties in this case had changed so that, where before a horizontal fracture was obtained, now a vertical fracture could be expected. The direction of the vertical fracture should be tangent to the old cavity. The problem then is how to connect with an old cavity.

Although the success ratio of fracture connections in older areas is lower than in virgin areas, it has been done many times. The connection can be accomplished in two ways. The first way is shown in case 6. This of course is a most welcome connection. The second kind, the one shown in this case, is not so welcome.

Here, the fracture was vertical. It extended up and connected with a dissolved finger from the old cavity. This type of fracture usually extends through one or more lens of impurity that cannot be dissolved, requiring extended pumping time to either erode the lens or remove enough salt from around it to allow it to crumble or cave. In several instances, long term pumping with 100% returns out of the target well never accomplished a low pressure connection.

COST AND OPERATIONAL COMPARISONS

The following table shows some comparable costs of raising salt by the three methods discussed. The following data is based on my experience and knowledge gained by association with the industry. The wells and locations are hypothetical and estimates are based on minimum costs.

As shown in Table I, fracturing is the most economical method of raising salt. This fact, however, is offset by several disadvantages, including the following:

1. In some areas, only a small percentage of success from fracturing can be expected.
2. Fracturing cannot be directionally controlled, and costs can be significantly increased by indiscriminate pumping and by extensive workover requirements.

New techniques need to be developed with the advantages of fracturing but not the disadvantages of failures or added development costs. Several techniques are being tested, but none have been proved at this time. In the meantime, some steps need to be taken to control the cost and use of fracturing.

1. Wells should be spaced between 400 and 600 ft apart.
2. The target well should have as much open hole as is practical to allow as large a target for the fracture as possible.
3. Well construction should be such that the conversion to a one-well system can be made.
4. A budget limit should be placed on the fracturing attempt. If the limit is reached, the operation should be converted to a one-well system. For the one-well system, tools have been developed that lower the cost and time of workovers.
5. Any alternatives, in case of the initial fracture's failure should be governed by the specific case.
6. As a last resort, prolonged injection should be tried.

FUTURE USE OF BRINE FIELD CAVITIES

Underground storage requirements all over the world are growing by leaps and bounds. Hydrocarbon and plant waste storage needs are making abandoned salt caverns of considerable value. This should be kept in mind by management when planning the development and operation techniques of a new salt cavern. The three important considerations are:

1. That adjoining cavities are connected at the base of the salt.

2. That the cavities are developed with a degree of symmetrical pattern.

3. That the cavities are not overworked. Overworking causes excessive roof caving or a dissolving of intervening walls.

Careful planning can alleviate some of the problems involved in connecting two wells and can allow for future use when the wells cease production.

ACKNOWLEDGMENTS

I want to thank Fenix & Scisson, Inc., for permission to present this paper.