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FOREWORD

The application of hydraulic fracturing to gas wells is a relatively new technique in Western Pennsylvania. This paper presents a study and evaluation of much of the obtainable data with a view toward increasing the success of this process and increasing gas production in this area.

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I. INTRODUCTION

Pennsylvania is the oldest oil and gas producing state and the one in which the industry had its beginning. In the years 1867 to 1870, the Bradford Field was developed making it at that time the major producing area in the world. Since then Pennsylvania has declined in importance as an oil and gas producing state. However, through the recent development of a technique known as hydraulic fracturing, it may be possible for production, particularly gas, to be increased in this important producing state. Except for a few isolated experiments, this technique was not used in Pennsylvania until early 1954.

Hydraulic fracturing is a process of pumping a viscous fluid containing a "propping agent" under high pressure down through a well bore and into the producing information. The purpose of this process is to cause a splitting in a desired section of a formation and thus make one or more connecting channels for flow into the well bore. The propping agent serves to hold the channels open after the pressure is withdrawn.

Although most producing formations in Western Pennsylvania respond well to hydraulic fracturing, this area is the most difficult in which to apply the treatment. This condition exists for two reasons, the first being poor completion practices such a running as little casing as possible, shooting the producing formation, cleaning out, and producing at maximum rates. Such wells are not suitable for fracturing. The second obstacle is the complete lack of records on reservoir information and engineering data. Such information consists of porosity, permeability, temperature and formation thickness. In many cases, it is not even known whether a well was shot or what completion method was used.

Since no organized study had ever been conducted of the available information on fractured wells in Western Pennsylvania, it was decided that an excellent opportunity now existed to do so. Only the gas phase of the industry will be considered in establishing criteria for the application of hydraulic fracturing with a view toward increasing its chance of success.

A. Review of Hydraulic Fracturing

For quite some time during cementing or water flooding operations, it had been noted that the use of high pressure would cause parting in a formation with resultant loss of fluid. This parting or fracturing in a formation was to be avoided and usually occurred when a pressure was obtained of approximately one pound per square inch per foot of depth. The Research Department of the Stanolind Oil and Gas Company experimented with this fracturing and developed a process which it licensed and patented in 1949 under the trade name Hydrafrac. The process has been accepted and has grown in five and one-half years from a treatment rate of 18 wells per month to over 3000 wells per month in 1955 and with over 30 organizations now licensed to perform fracture service. While this process is primarily used to increase and extend production, it has a secondary application in increasing water flow in injection wells in water flood operations and in gas storage fields to increase the rate at which gas may be injected, and of more importance, withdrawn during periods of high consumption.

1. Types of Fracturing Fluids

The fracturing process is known by several different names, some of them being patented and named for the fracturing fluid used. The purpose of the different combinations being to obtain a fluid that is the least foreign and most compatible to the formation being fractured. Additional desirable characteristics are low fluid loss, minimum plugging effect on the formation, and viscosity consistent with required sand suspending properties. A lower viscosity will reduce the frictional drop in the tubing and reduce pump requirements. Some of the more commonly known types of fracturing fluids are as follows.

Gel Frac which is a trade name given to a viscous gel prepared from a hydrocarbon, such as kerosene, diesel oil or special oil mixtures which have been treated with an additive such as napalm to give the fluid sufficient viscosity.

Emulsifrac is a trade name applied to a crude oil jelled by use of an additive. There is a convenience and economic advantage in using oil that is produced in the well.

Acid Frac is any viscous fluid which contains from five to twenty per cent acid. This particular mixture finds a use in calcareous formations.

Water Frac is the name applied to a method for thickening water for fracturing purposes, especially useful for water wells, water disposal and injection wells for water flooding. A recent development in the San Juan Basin has been the successful fracturing of gas wells using only water without sand.

2. Fracturing Procedure

The procedure for hydraulic fracturing may be broken down into four basic components. However, it must be realized that there are many variations within each component and possible combinations of the components, depending on the "tailored" treatment desired for a particular well bore.

a. The first step is the preparation of the fracturing fluid which was described in the previous section under types and which is selected according to the type of well bore and formation to be treated. Diesel oil and kerosene are the most common fluids used for gas wells with kerosene being used almost exclusively in Western Pennsylvania. Sand, which serves as a propping agent in the crevices of the fractures, is then added to this fluid in proportions of from one-quarter to three or more pounds per gallon.

b. The second consideration and probably most important is to obtain a high pressure and injection rate using high pressure pumps. The pressure exerted must be in excess of that due to the overburden and the pressure is transmitted to the formation by the viscous fluid pumped into the treated zone. The pumps used must be of suitable capacity and horsepower to obtain the proper pumping rate and pressure to make and extend the fractures. This phase of the procedure will be discussed in more detail as it is the part of the procedure that may be responsible for a successful or unsuccessful fracture.

c. The third step in the process is the addition to the fracturing fluid of a concentrated gel breaker to insure complete break down of the viscous gel especially in low temperature, dry gas reservoirs.

d. The fourth step is the reverting of the viscous gel to a low viscosity fluid in a period of hours. On release of the excessive pressure which was necessary to fracture the formation, the sand acts as a propping agent to hold open the fracture and the natural production flushes the treating chemicals from the formation. If the production does not accomplish this natural flushing, then the well must be cleaned out.

B. Major Gas Producing Formations

The Appalachian Geosyncline is made up of three major basins. A southern basin with its thickest sediments near Birmingham, Alabama, a central basis with its thickest sediments near Elkins, West Virginia, and a northern basin with its thickest sediments near Altoona, Pennsylvania. Northwest of the Appalachian Geosyncline and roughly paralleling it lies the Cincinnati Arch. Geographically, western Pennsylvania lies to the west of the northern basin where the formations dip down sharply from the Cincinnati Arch to the northern basin.

Gas has been found in western Pennsylvania in twenty-seven different geological formations. However, only about a dozen produce in any commercial quantities with the Bradford being the foremost producer. Other gas producing formations to be considered are the Gordon Third sand, Fourth sand, Fifth sand, Bayard, Speechley, Tiona, Balltown, Sheffield, Kane, Elk and Oriskany.

II. ANALYSIS OF WELLS BEFORE FRACTURING

A. Production History

In evaluating a well for the application of hydraulic fracturing, its production history is one of the more important factors to be considered. It is quite obvious that a depleted reservoir is not going to react with as great a production increase as a reservoir that is in its early production life and retains most of its original recoverable gas. In general, if a well has declined very slowly over a period of years, it can be assumed that the decline was due to normal withdrawal of the recoverable gas and depletion of the bottom hole pressure. In contrast, consider a well which was brought in with a high initial production, then declined very rapidly to a lower level which it maintained as a relatively flat decline curve over a period of time. In this type of production, the possibility exists of having exhausted the producible gas under the existing permeability and pressure conditions fairly close to the well bore. If this assumption is correct and the well is fractured, increasing the flow channels about the well bore, there is an excellent chance of increasing and maintaining a higher production rate.

The maximum efficient production rate of a well is another important factor in considering a well for fracturing. Any well that has been produced beyond its M.E.R. for any length of time must be evaluated with caution. Subjecting gas wells to extreme conditions of flow causes sand formations in the well to cave, aggravates water "coning," channeling and increases the possibility of trapping gas in the underground reservoir with water. Such damage to the well is permanent and it usually will

not respond to fracturing. In other words, production from the reservoir will not be helped by increasing the flow channels around the well bore. A gas well producing other than connate water is almost 100 per cent certain to show little or no improvement on fracturing.

B. Well Completion

In considering well completion methods, it should be remembered that hydraulic fracturing is as effective through perforations in casing as it is in open hole. For economical reasons, most gas wells have not been properly cased and since the advent of fracturing, it has become undesirable to have several hundred feet of open hole and a shot hole or pocket below the producing formation. Improper well completion methods may be a contributing cause of a permeability block about the well bore. In addition, the well must be completely clean before fracturing. If it has been properly completed, it should stay clean after fracturing and the production curve well not dip sharply after a short production period.

C. Application of Engineering Principles

1. Volume and Injection Rate

The effectiveness of any fracture is dependent upon the extent of that fracture from the well bore into the formation with as little loss of the fracturing fluid as possible. To obtain effective fractures requires a high fluid injection rate during the fracturing process. This rate of fluid displacement into the well bore is directly proportional to the injection pressure and inversely proportional to the viscosity of the fluid. The injection rate becomes of more concern as the fracture is extended due to unavoidable fluid loss and increase of fracture volume. George Roberts, Jr.[1] gives the following estimates of fluid required to achieve the fracture radius in tight formations with one pound of sand added per gallon of fluid.

Bbls. of Fracturing Fluid	Radius in Feet
20 - 40	100
200 - 400	200
500 - 800	400
1000 - 2000	600

If sufficient reservoir and well data were available, it would be possible to determine if a well had a permeability block about the well bore. Such a well would be a good prospect for fracturing to increase the flow channels into the well. This permeability block is referred to as the skin effect[2,3,4] which has been recognized and discussed in the literature. Investigators have attempted to explain marked incongruities that appear in the pressure behavior of draw down and build up

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[1]References are listed in the Bibliography.

curves. These pressure curves are indicated by a bottom-hole pressure gage in a flowing well followed by a period of shut-in and compared with the theoretical aspects of fluid flow into a well. If fluid flows were computed, it would be found that a large pressure gradient exists in the immediate or the adjacent areal extent in the sand close to the well bore. In explanation of these excessive pressure gradients, it is assumed that permeability of the formation at and near the well bore is substantially reduced for some reason. This reduction in permeability can be caused in a gas well by such things as improper drilling, completion, and production practices.

To visualize the problem, the well bore may be considered to be entirely sheathed in a semi-impervious skin which hydraulic fracturing with its long extended crevices would be ideally suited to penetrate. However, it is not possible to use this direct skin effect calculation as a positive means of selecting wells for fracture and one must resort to round-about ways of solving the problem.

It has been established that increasing the radius of a fracture will produce a corresponding increase in production after break-through of any existing permeability block.

An electric analog study has been conducted by Dr. Paul Crawford[5] to determine the effect of fracture size on productivity. This study of necessity represents conditions of uniform vertical and horizontal permeability, but it does give valuable and usable information. From this study, fracture systems appear to fall into the following categories:

One or more vertical fractures

One or more horizontal fractures

Random fractures in various planes.

In this study, it was shown that the effectiveness of any one size fracture will vary little more than ten per cent regardless of the plane in which the fracture is lying. The study also illustrates the increase to be expected by extending a fracture beyond a blocked area and, therefore, changing the flow pattern to increase productivity by a factor of four or five.

The electric analog study revealed further information concerning single and multiple fractures.

a. When vertical and horizontal permeability are the same, one 75 foot fracture will produce at the same rate as two 75 foot fractures. As the fractures become longer, some benefit can be derived from two fractures. As the fractures become shorter, no benefit can be gained by producing through more than one fracture.

b. When the horizontal permeability is three times the vertical permeability, two 75 foot fractures will produce about 1.25 times the fluid that can be produced by one 75 foot fracture. Three 75 foot fractures will produce little more than twice that of one fracture.

c. When the horizontal permeability is five times the vertical permeability, two 75 foot fractures will produce twice as much as one fracture, three 75 foot fractures will produce only 1.1 times as much fluid as two fractures.

The above conditions are true in pay zones having thicknesses up to 150 feet and in wells having 100 per cent permeability block except at the point of fractures.

2. Single and Multiple Fracture Methods

There are two distinct methods to be considered in applying the fracturing process to wells, the single fracture method and the multifrac

method in which the process is applied two or more times. The single fracture method is generally recommended when thin sections of a formation usually under 30 feet are to be fractured. The cracks or fractures offer only negligible resistance to the flow of gas and are capable of increasing well productivity by exposing large areas of the producing formation to relatively open drainage channels, thereby reducing the resistance to flow of the gas to the well.

In field application, it is not always possible to isolate properly that portion of the producing formation to be treated and many times it is desired to fracture a very thick formation of two or more producing zones. This led to the development of the multiple fracture technique wherein a single fracture is created and then plugged at its face on the well wall by introducing into the fracturing fluid a suitable plugging material to prevent further penetration into the crack. By so restricting the fracturing fluid to the well bore, it is then possible to increase the hydraulic pressure in the hole to some higher value, at which another fracture occurs at some other elevation. Each fracture so formed is extended with the fracturing fluid containing no plugging material. By repeating this procedure, sealing successively formed fractures with a suitable plugging material, it is possible to create multiple fractures in any one isolated section of the well. The two key points on which the success of the multiple fracturing method depends are: effective sealing of previously formed fractures and removal of the plugging agent at the completion of the treating operation to allow free flow of the gas into the well through all the fractures created.

In multiple fracturing, the plugging agent must obviously be temporary in nature so that it will not restrict fluid flows. Among other factors

which must be considered are effect of temperature and pressure, and the melting point and solubility of the agent. The material most commonly used at the present time to meet these requirements is compressed and ground pellets of naphthalene.

III. ANALYSIS OF WELLS AFTER FRACTURING

A. Comparison of Data

An accurate and reliable evaluation of a well's performance and its comparison with other wells must be based upon complete and accurate engineering information. In making this study, the lack of adequate engineering data on wells in the area was soon realized. The technique of fracturing in Western Pennsylvania is so new that there is no real standardization for taking and recording field data. The kind and quantity of data taken in one area would vary considerably from that taken in another area and it would also vary among the different companies. To further add to the difficulties, vital field data would be carelessly recorded, if not left out entirely. If the missing information could not be located, it was necessary to disregard the well so that the over-all results would not be distorted. In some cases, wells were used for the information they would contribute to a certain phase of the study.

After assembling and tabulating all the data that could be obtained within the available time, it was decided to use 146 wells in Western Pennsylvania that contributed the most information both in quantity and accuracy upon which to base comparisons. All data used are tabulated for ready reference in the four appendices. Appendix I is a tabulation of the general description and performance of the wells. Appendix II is a tabulation of the hydraulic fracturing information that could be found on each well. Appendix III lists 74 wells on which monthly gas production could be obtained before and after the fracturing treatment. Appendix IV lists 37 wells on which a break down of costs is given in tabulated form.

1. Engineering Data

Normally a gas well operator cares very little about any engineering data on his well and most times knows nothing about it, his only consideration being that it is producing gas and showing a profit. However, if this same operator considers hydraulic fracturing his well to increase production and profits, he suddenly becomes very interested in how and why his well is producing and endeavors to enlighten himself on this new born interest. Hydraulic fracturing is not a panacea for all production ills and its costs must be carefully considered against possible increase in future production. Making this decision rests purely on an analysis of what information can be obtained about the well.

Usually the age of the well is known, that is how long it has been producing, the current and cumulative gas production is known and a measurement can be made of its open flow to the atmosphere by pitot tube. The well is normally but not always shut-in for a period of time and its well head pressure taken. The period of shut-in depends on the whim of the operator and how long he desires to lose production on that well. Most operators allow at least 24 hours and some much longer time depending on the rate of build up and whether or not sufficient pressure is recorded. The combination of the open flow and well head pressure measurements are usually the determining factor whether or not a well will benefit from a fracture treatment. This combination may be considered in different ways. A well is given an even chance if it has a low open flow and high well head pressure or low well head pressure and high open flow. It has an excellent chance if both open flow and well head pressure are high and a poor chance if both open flow and well head pressure are small. Of course, this consideration is always tempered with the performance of other wells in the area and the current gas production.

2. Geological Data

The thickness of the formations and the location and thickness of the producing zones are in very many cases taken from driller's logs. In some instances electric logs and temperature surveys have been made prior to fracturing in order to locate the zones more accurately. In the wells being considered, the Bradford formation runs from a minimum thickness of seven feet to a maximum of 177 feet with an average of 45 feet. The Speechley formation runs from a minimum of 18 feet to 55 feet with an average of 34-1/2 feet. The Tiona formation runs from a minimum of 11 feet to a maximum of 26 feet with an average of 19 feet. The Fourth and Fifth sands have an average of 18 and 30 feet respectively. On four wells, the Balltown showed an average of 25 feet. On five wells, the Sheffield showed an average of 33 feet, the Kane an average of 14-1/3 feet on six wells. The Oriskany ran from a minimum of 92 feet to a maximum of 241 feet with an average of 123 feet on seven wells. The Bayard formation averaged 16 feet on two wells.

3. Application of Methods

The final selection for the method of hydraulic fracturing a well is dependent on several factors. To be considered are the formation thickness, the number of producing zones, the thickness of each and what the size of the fracture zone or zones will be. At this point, it must again be pointed out that the fracturing fluid will follow the path of least resistance and that this path cannot be left to chance.

Of the 146 wells evaluated, formation and producing zone depths were obtained on 125. Of this number, 89 wells had a fracture zone in excess of 30 feet which indicated the multifrac method was in order.

Detailed fracture information was obtained on 132 wells, seven in excess of the number on which formation depths were obtained and it was found that 128 were treated by the single frac method while only four wells were treated by multifrac.

For a fracturing fluid kerosene was used almost exclusively, only three cases being found to be otherwise. Crude oil was used in one well fractured in the Tiona formation in September of 1954 with practically no success. Diesel oil was used in two wells, one in the Third sand, in July of 1954, with no change in production, and one well in the Fourth sand in September 1954; the well was damaged as a result of the treatment.

In 97 of the wells examined, it was found that in 66, the fracturing fluid was followed by a jel breaker while in 31 wells no breaker was used. The sand-gel mixture is fairly well standardized to one pound of sand per gallon of jel and the exceptions are limited in range from one-half pound to one and a half pounds per gallon.

B. Effect on Production

Whether a fracturing job on a well was successful or unsuccessful rests in the final analysis on actual gas production. A comparison must be made of actual gas production before and after fracture and the longer the periods used for comparison, the more accurate will be the evaluation. While production figures are the most valuable asset to a study of this kind, they are probably the most difficult to obtain. All production information is of a rather confidential nature. Another source of difficulty is that the production from two or more wells belonging to the same owner will go through one meter so that the production from an individual well cannot be determined. However, the primary source of difficulty results from the newness of the fracturing technique itself to this area. As stated before the accuracy of an evaluation on a fractured well is dependent on the observed periods of production both before and after fracture. Appendix III shows in tabulated form for comparison the production on 74 gas wells. Except in a few cases, the production figures for these wells are shown for six or more months after fracture. The effect of fracturing on production is shown in the following summary.

Bradford	33 old wells increased production
	16 new wells increased production
	1 old well decreased production
	1 new well decreased production
	3 old wells, no change in production
	5 new wells, no change in production
Fifth Sand	1 new well, no change in production
Bayard	1 new well increased production
Speechley	2 old wells increased production
	2 old wells decreased production
	1 old well, no change in production
Speechley and Tiona	1 old well, no change in production
Tiona	1 old well increased production
	1 new well increased production
Balltown	1 new well, no change in production
Sheffield	2 old wells increased production
	1 old well decreased production
	1 new well, no change in production

C. Economic Aspects

One of the more rewarding results of this study has been the break down of the cost to fracture a well. This is one of the most important considerations in making a decision to fracture, yet there is a general lack of knowledge on the subject. Not only is the over-all cost important, but unit costs for the same item will vary with different wells. While there is no intention of going into detail on costs, Appendix IV was prepared on 37 wells showing seven major categories of expense. The service company charge is based on the amount of equipment necessary to properly fracture the well. The cost of kerosene is merely the amount used multiplied by the unit cost. The most interesting item is the cost of surveys which average between $300 and $500. This is the least costly item in the entire operation and is in most cases deleted in order to save this minor expense. Surveys will give much preliminary information with which to arrive at a fracture decision and should always be made. The information which they supply may save much expense later on or perhaps determine that the well would not be a good prospect for fracturing. Fracturing labor consists of all wages paid to set tubing and prepare the well for the service company. Clean-out labor consists of all wages paid after the well is fractured. Other costs are miscellaneous and include such items as accidents and making the well accessible to the service equipment.

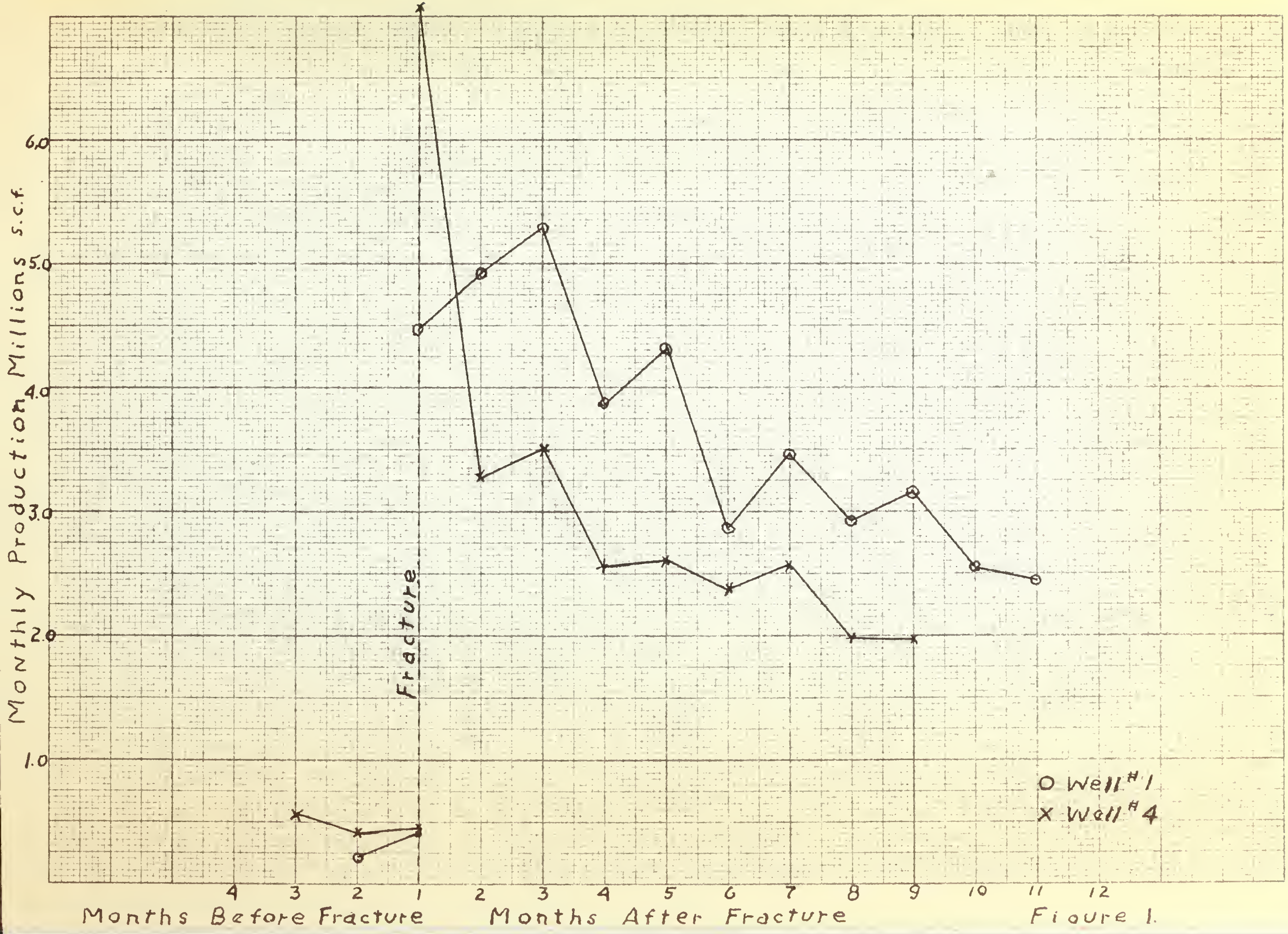
Considering all possible expenses due to fracturing on these 37 wells, the average per well is $9,312.87. The current price of gas at the well head averages around 20 cents per 1,000 cu. ft. In the area where most of these wells were drilled, it is customary for the operator

to pay an annual fee in lieu of royalty payments. This fee, of course, should be deducted from income from gas sales in determining pay out on a fracture job. Actually the amount to be subtracted for such annual payments is relatively small. At the rate of 20 cents per 1000 cu. ft. a fractured well to be considered successful must produce 46,564,000 cu. ft. of gas more than it would have produced if unfractured. It is estimated that half the fractured wells in Western Pennsylvania will return the investment in from 12 to 18 months after having been fractured. To substantiate this statement, it is interesting to note that out of the 56 wells whose production had increased, five had already or were very likely to return their fracturing costs within 12 months and 23 more wells had an excellent chance of doing so within 18 months.

IV. CORRELATION OF FRACTURED WELLS

A. Production Decline

Hydraulic fracturing is so new to Western Pennsylvania that there are insufficient post-fracturing data to draw any specific conclusions as to production. Figures 1 and 2 show graphically the effect of fracturing on the first four wells used in this study. It may be said that in a successful fracture, there is a period of flush production for several months up to a year after the well is fractured. Beyond this point, it may reasonably be assumed that the production curve of the fractured well will continue to decline and approach the production of the well had it not been fractured. If one were to speculate further, it is believed that the decline curve of the fractured well will gradually flatten out and continue to decline approximately parallel to the expected decline curve of the unfractured well but somewhat higher. This interpretation is based upon the premise that by creating new channels of flow about the well bore, the same volume of production may be recovered in much less time than it would take in the conventional manner of flow.



Monthly Production Millions s.c.f.
6.0
5.0
4.0
3.0
2.0
1.0
Fracture
O Well #1
X Well #4
4
3
2
1
2
3
4
5
6
7
8
9
10
11
12
Months Before Fracture
Months After Fracture

Figure 1.

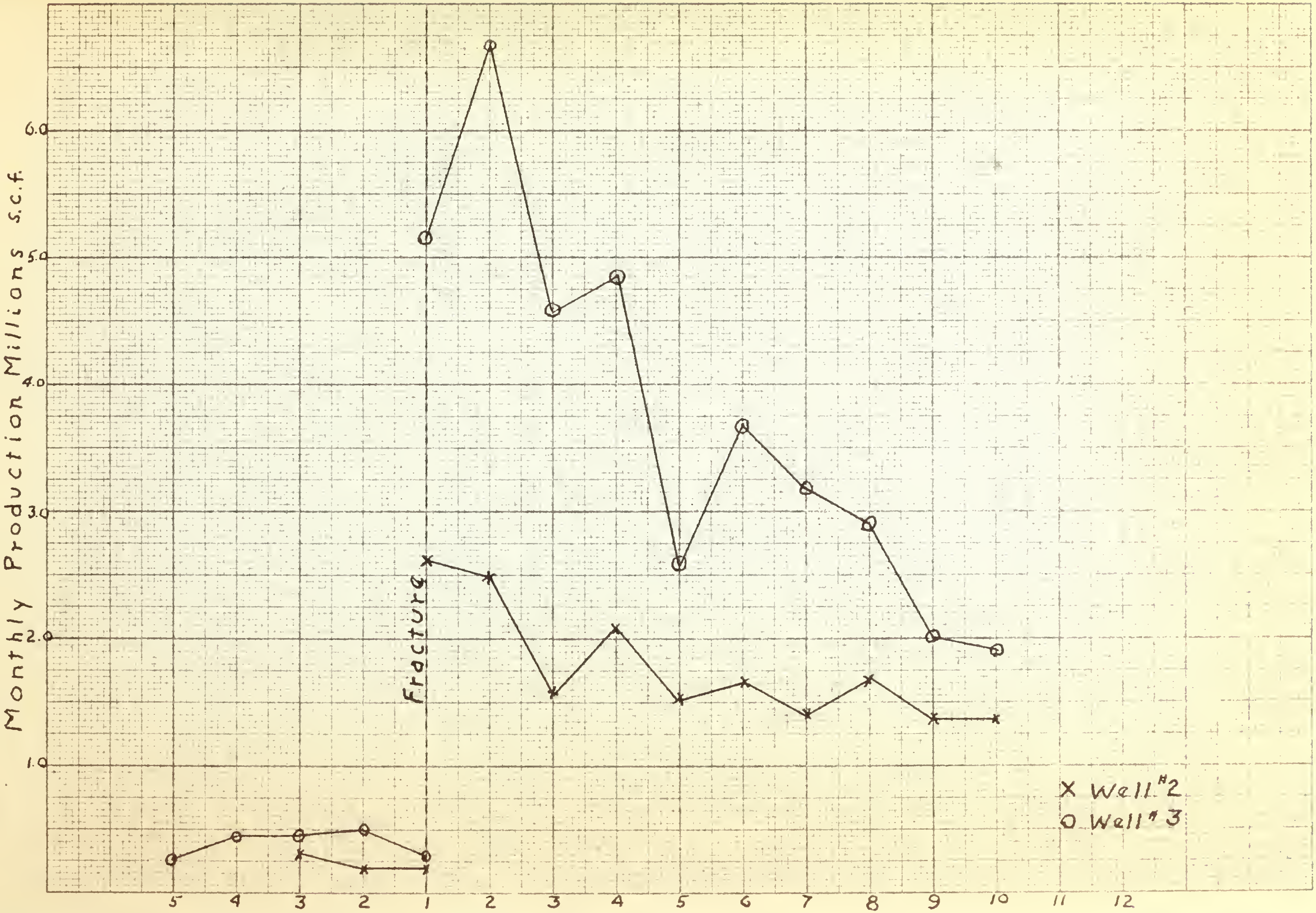

Monthly Production Millions s.c.f.
6.0
5.0
4.0
3.0
2.0
1.0
Fracture
X Well #2
O Well # 3
5
4
3
2
1
2
3
4
5
6
7
8
9
10
11
12
Months Before Fracture
Months After Fracture

Figure 2

B. Geological Relationships

The Bradford formation is by far the most important producing formation in Western Pennsylvania and, consequently, the most highly exploited. It can be said that the formation in general responds well to fracturing and that if care is used in the selection of wells, this formation will give the highest chance of success. While the Tiona shows up well, the experiences with this formation has been too limited to make any conclusive recommendation. The Speechley and Sheffield formations appear very good from the wells that are successful, but the percentage of successful wells is small by comparison with the Bradford.

Perhaps the most interesting formation open for speculation is the Oriskany. While results have been disappointing, there have been a couple of outstanding successes in this formation and it probably is the next formation after the Bradford that would warrant further exploration especially considering the success with which the Oriskany is being fractured in West Virginia and Maryland.

It is realized that not enough information has been gained on the other formations to draw any definite conclusions, but isolated cases of outstanding success may some day make these formations popular for fracturing.

C. Open Flow Relationships

The open flow results of the fractured wells used in this study are shown in the following summary.

Producing Sand	No. Wells	Total Open Flow Before Mcf./Day	Total Open Flow After Mcf./Day	No. Times Increase
Bradford	95	2185.4	48639.1	22.2
3rd Sand	1	44.7	43.2	0
4th Sand	3	72.8	82.1	0
5th Sand	3	116.5	351.0	3.0
Bayard	3	72.0	101.7	1.4
Speechley	10	178.9	1453.2	8.1
Speechley and Tiona	1	22.7	32.0	1.4
Tiona	5	122.4	398.8	3.2
Balltown	4	36.0	1335.0	37.0
Sheffield	5	122.5	817.0	6.6
Kane	6	124.5	874.6	7.0
Elk	2	8.7	70.0	8.0
Oriskany	8	1074.0	9556.9	9.0

This tabulation gives at a glance the total relative rates of open flow increase that have been experienced from the various gas producing formations.

The fracturing procedure in this area has become fairly uniform. In the 146 wells evaluated, kerosene was the fracturing fluid with three exceptions, crude oil was used in one and diesel oil in two.

V. SUMMARY AND CONCLUSIONS

Statistical analysis of fracturing on wells in Western Pennsylvania reveals that in the Bradford formation, 49 wells showed increased production, two decreased production and eight showed no change. In the Fifth Sand one well showed no change in production. In the Bayard, one well increased production. In the Speechley, two wells increased production, two decreased production and one showed no change. Two wells in the Tiona increased production and one well in the Balltown showed no change. In the Sheffield, two wells increased production, one decreased production and one well showed no change. In all formations, 56 wells increased production, five decreased production, and 12 showed no change.

Out of the 56 wells whose production had been increased by fracturing, five had already or were very likely to return their fracturing costs within 12 months and 23 more wells had an excellent chance of doing so within 18 months. This indicates that of the successfully fractured wells whose production had been increased, it can be expected that 50 per cent of the wells will return their cost of fracturing within a period of 18 months.

One of the most interesting aspects of this study has been the relationship between the thickness of formation fractured and success of the operation. While a 30 foot zone is the generally accepted maximum for fracture, by the single frac process, it was found that in 67 per cent of the successful wells evaluated, the zone thickness exceeded this recommended figure. This would seem to indicate that even the thicker formations in Western Pennsylvania respond well to single fracturing treatments, eliminating the need for the more expensive multifrac treatments. Four wells were evaluated in which the multifrac process was used. Two of these were in the Fifth Sand, one in the Sheffield, and one in the Kane. The results in all four cases were disappointing.

A. General Criteria for Application of Hydraulic Fracturing

1. A well which was brought in with a high initial production, then declined quite rapidly to a lower level which it maintained as a relatively flat decline curve over a period of time, may be considered a good prospect for fracturing.

2. Well history should be correlated with the type of drive existing in the reservoir. The history of the water production from a well gives a good insight into the type of reservoir which is present and aids in determining whether the water produced is connate or from a water drive. Wells that make a small amount of water each day which does not increase over a period of time and which fluctuates in proportion to production may usually be assumed to be producing connate water. In wells where the water production curve climbs in relation to production, it is possible that a water drive is present or the well has been damaged and water is fingering through the formation making such a well a poor prospect for fracturing.

3. The work-over history of a well is an important consideration in any well evaluation. Analysis of the wells used in this study appears to support the belief that wells which have been shot with nitroglycerin will not respond as well as those that have not been shot prior to fracture treatment. Lime or sandy lime wells that have been acidized can usually be expected to fall below the expected results from fracturing. When it is considered that fracturing increases production by increasing the flow channels to the well bore, it seems reasonable to assume that the process has a much better chance of success in a virgin well bore than one that has been previously worked over to accomplish a similar purpose.

4. To prevent unwarranted expense and failure, only wells and equipment in good condition should be selected, as high pressures will be encountered in the process. Remembering that the fracture will follow the line of least resistance, a good primary cementing job is essential to confine the fracturing fluid to the zone to be treated. Every well evaluated in this study used a cemented packer. Well head, casing, packers and tubing strings should be able to withstand treating pressures. Well number 82 in this study costing $25,956.34 to fracture is an outstanding example of the high cost of fracturing if the equipment is not in good condition and the well properly prepared for the treatment.

B. Specific Criteria for Application of Hydraulic Fracturing

1. The first and foremost recommendation to be made is that any well being considered for fracture should have an electric or gamma ray, temperature, and caliper log run on it to gain as much preliminary information as possible. Through the use of the gamma ray log the pay zones may be located which may help to reduce the thickness of zone to be treated. The temperature log is a definite aid in determining whether the temperature is sufficiently high for the fracturing fluid used to revert to a low viscosity fluid without the use of a jell breaker. The caliper log is extremely important and helpful in anticipating fracturing difficulties. In this area tubing is run in open hole well below the casing. The packers between the tubing and open hole are always cemented to lessen the possibility of packer failure due to the high fracturing pressures. In addition to cementing the packer, it is customary to use 10 to 15 bags of cement above the packer between the tubing and well wall. This, of course, results in a higher than normal cost of fracturing as the tubing is not pulled and reused. However, by leaving the tubing in, the well remains cleaner over a longer period of time thus saving future clean out costs.

2. A minimum of three inch outside diameter tubing is recommended especially where substantial increases of flow are expected. The larger the tubing diameter, the less friction loss in pumping the fracturing fluid, hence more effective pressure at the zone to be fractured.

3. A study of the appendices will show that prior to fracturing, no exact value of open flow and well head pressure may be stated that is necessary for success. While there should be sufficient pressure to bring gas into the well bore, it does not appear to be an absolute necessity that high pressures exist. A rule of thumb that is offered for consideration is that if a well can be shut-in for 48 or 72 hours and then recover

production of the shut-down period in approximately the same length of time, the chances for success are good.

4. Normally the service companies recommend a maximum fracture zone of 30 feet when using single frac and that multifrac be used on thicker zones. Probably the most important result of this study is the finding of the practicability of using single frac in lieu of multifrac for extensive formation thicknesses. In order to evalute the production of fractured wells against the thickness of zone fractured, three ranges of thickness were chosen. The first range was from zero to 30 feet. The limit of this range was chosen because of it being the generally recommended maximum for single frac. The second range extended from 30 to 60 feet giving a thickness up to double the recommended maximum. The third range consisted of wells whose fracture zone was in excess of 60 feet.

In the Bradford formation there were 11 wells in the first range whose average production was increased 5.57 times over what it was before fracture. In the second range there were 17 wells whose average production was increased 10.5 times over what it was before fracture. In the third range 11 wells increased production 6.38 times over average production before fracture. Such figures seem to refute the argument that multifrac should be used in zones whose thickness exceeds 30 feet. In formations other than the Bradford, information was too limited to draw any specific conclusions.

5. As a last consideration, it must be realized that all factors cannot be so fully evaluated that 100 per cent success is assured, however, it is believed that the chance for success may be greatly enhanced if more information on existing and new wells is taken, recorded and thoroughly evaluated. While much of the information gathered for this study is not new to a lot of people, it is thought that no one person has had access to all of it or has taken the time to make an evaluation of this type on

APPENDIX I

GENERAL WELL DESCRIPTION AND PERFORMANCE

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day Before	Open Flow Mcf./Day After	W.H.P./Hours Shut In Before	W.H.P./Hours Shut In After	Dia. Tubing In.	Remarks
1*	Armstrong	3-28-55	Bradford	12.0	696.0	815/8	730/18		8 years old
2	Armstrong	5-26-55	Bradford	17.9	284.0	N.T.##	575/16		34 years old
3	Armstrong	6-8-55	Bradford	21.0	506.0	N.T.	785/18		3 years old
4	Armstrong	6-23-55	Bradford	16.0	407.0	590/120	820/16		8 years old
5	Armstrong	6-21-55	Bradford	28.3	321.0	615/72	752/72		7 years old
6	Armstrong	7-6-55	Bradford	21.0	852.0	N.T.	560/72		Old well
7	Armstrong	8-3-55	Bradford	30.4	36.5	585/20	N.T.	3-1/2	Old well
8	Armstrong	4-5-55	Bradford	12.5	823.0	N.T.	975/18		New well
9	Armstrong	3-9-55	Bradford	21.0	475.0	N.T.	560/40		11 years old
10	Armstrong	8-2-55	Bradford	6.3	200.0	360/24	930/16	3-1/2	13 years old
11	Armstrong	8-23-55	Bradford	4.0	696.0	640/72	800/16	3	33 years old
12	Armstrong	8-25-55	Bradford	3.9	87.8	320/60	320/24	3-1/2	34 years old
13	Armstrong	10-5-55	Bradford	8.4	581.8	345/24	700/18	3-1/2	8 years old
14	Armstrong	9-21-55	Bradford	22.7	100.0	525/22	700/24	3-1/2	New well
15	Armstrong	10-11-55	Bradford	25.8	622.0	800/18	980/16	3-1/2	New well
16	Armstrong	11-9-55	Bradford	5.0	696.0	525/22	960/90	3-1/2	13 years old
17	Armstrong	12-12-55	Bradford	10.9	354.0	535/96	1050/18	3-1/2	12 years old

... the same well used in this study. ## Not Taken

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day Before	Open Flow Mcf./Day After	W.H.P./Hours Shut In Before	W.H.P./Hours Shut In After	Dia. Tubing In.	Remarks
18	Armstrong	12-20-55	Bradford	21.0	1100.0	825/24	975/20	3-1/2	New well
19	Armstrong	1-18-56	Bradford	9.7	1100.0	590/20	1015/16	3	New well
20	Armstrong	9-3-55	Bradford	10.0	167.0	475/18	N.T.	3	Old well
21	Armstrong	8-4-55	Bradford	17.0	143.0	453/71	N.T.	3	Old well
22	Armstrong	12-28-55	Bradford	6.0	222.0	85/144	520/18	3	Old well
23	Armstrong	7-20-55	Bradford	10.0	215.0	498/48	N.T.	3	Old well
24	Armstrong	8-13-55	Bradford	30.0	175.0	510/13	N.T.	3	Old well
25	Armstrong	11-22-55	Bradford	21.0	82.0	320/70	880/15	3	Old well
26	Armstrong	11-17-55	Bradford	15.0	10.0	300/20	670/117	2	Old well
27	Armstrong	6-3-55	Bradford	24.3	368.0	650/48	N.T.	3	Old well
28	Armstrong	9-9-55	Bradford	20.0	71.0	425/48	N.T.	3	Old well
29	Armstrong	8-1-55	Bradford	18.0	500.0	400/48	600/24	2	Old well
30	Armstrong	8-14-54	Bradford	31.0	298.0	175/24	500.48		Old well
31	Armstrong	10-21-54	Bradford	6.0	231.0	865/285	870/39		New well
32	Armstrong	12-6-54	Bradford	12.0	520.0	760/72	N.T.	3	New well
33	Armstrong	2-1-55	Bradford	12.0	167.0	760/64	470/16	3	New well
34	Armstrong	3-23-55	Bradford	12.0	147.0	450/90	450/72	2	New well
35	Armstrong	4-20-55	Bradford	6.0	436.0	650/99	900/4	3	New well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day Before	After	W.H.P./Hours Shut In Before	After	Dia. Tubing In.	Remarks
36	Armstrong	6-6-55	Bradford	28.0	489.0	470/32	400/24	2	New well
37	Armstrong	7-2-55	Bradford	20.0	250.0	675/24	675/24	2	New well
38	Armstrong	9-30-55	Bradford	5.0	68.0	450/72	325/48	2	New well
39	Armstrong	1-9-56	Bradford	11.2	392.6	520/44	845/16		8 years old
40	Armstrong	1-16-56	Bradford	6.9	70.7	285/70	380/24	3	29 years old
41	Armstrong	1-12-56	Bradford	27.6	48.0	480/44	655/96	3	10 years old
42	Armstrong	4-19-56	Bradford	7.7	363.0	430/41	990/48		Shot, old well
43	Armstrong	2-24-56	Bradford	20.0	590.0	745/240	1150/50		New well
44	Armstrong	3-19-56	Bradford	4.4	512.0	282/24	N.T.		New well
45	Armstrong	2-2-56	Bradford	20.0	1238.4	500/72	510/1		New well
46	Armstrong	2-17-56	Bradford	23.0	500.0	550/47	N.T.		New well
47	Armstrong	4-28-56	Bradford	36.4	155.0	480/24	N.T.	3	New well
48	Armstrong	5-8-56	Bradford	90.0	600.0	940/48	1105/24	3	New well
49	Armstrong	4-3-56	Bradford	35.0	213.0	N.T.	N.T.		Old well
50	Armstrong	1-30-56	Bradford	17.0	219.0	290/16	N.T.		Old well
51	Armstrong	6-20-55	Bradford	5.4	266.0	625/24	970/15		Old well
52	Armstrong	4-6-56	Bradford	0.7	572.0	660/336	920/1		Old well
53	Armstrong	3-26-56	Bradford	6.0	304.0	525/20	930/88		Old well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day		W.H.P./Hours Shut In		Dia. Tubing In.	Remarks
				Before	After	Before	After		
54	Armstrong	4-13-56	Bradford	11.8	159.0	252/16	276/96		Old well
55	Armstrong	4-10-56	Bradford	10.6	71.6	333/42	660/42		Old well
56	Armstrong	5-1-56	Bradford	3.5	28.3	155/24	425/16	3-1/2	Shot, old
57	Armstrong	2-21-56	Bradford	23.8	1032.0	855/96	890/24	3-1/2	New well
58	Armstrong	3-6-56	Bradford	10.8	1012.0	475/22	960/24	3	New well
59	Armstrong	3-22-56	Bradford	22.9	1055.0	805/20	1075/70	3-1/2	New well
60	Armstrong	3-19-56	Bradford	4.8	80.9	250/70	580/90	3-1/2	30 years old, shot
61	Armstrong	3-21-56	Bradford	0.15	6.3	410/48	400/24	3-1/2	25 years old, shot
62	Armstrong	4-18-56	Bradford	0.95	475.0	90/22	1070/72	3-1/2	30 years old
63	Armstrong	4-24-56	Bradford	6.3	487.4	350/20	1120/24	3-1/2	New well
64	Jefferson	8-15-55	Bradford	12.5	113.0	400/24	785/24	3	12 years old
65	Jefferson	8-22-55	Bradford	14.2	455.2	605/72	1010/16	3	12 years old
66	Jefferson	9-20-55	Bradford	3.1	1666.0	510/20	900/18	3	25 years old
67	Jefferson	10-5-55	Bradford	4.8	121.0	320/24	655/17	3-1/2	13 years old
68	Jefferson	10-19-55	Bradford	12.5	117.6	450/18	895/24	3-1/2	New well
69	Jefferson	11-7-55	Bradford	15.5	681.1	460/72	600/16	3-1/2	6 years old
70	Jefferson	11-30-55	Bradford	28.3	1443.0	450/44	590/16	3-1/2	7 years old
71	Jefferson	12-27-55	Bradford	10.9	622.0	970/72	1015/18	3-1/2	New well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day		W.H.P./Hours Shut In		Dia. Tubing In.	Remarks
				Before	After	Before	After		
72	Jefferson	1-10-56	Bradford	12.5	412.0	415/22	560/18		9 years old
73	Jefferson	1-20-56	Bradford	17.9	593.0	775/72	1010/24	3	New well
74	Jefferson	3-27-56	Bradford	25.8	1555.0	650/24	800/24		New well
75	Jefferson	2-7-56	Bradford	1.8	3.1	115/20	160/72		9 years old
76	Westmoreland	8-10-55	Bradford	2.5	133.4	N.T.	N.T.	3	32 years old
77	Westmoreland	2-25-55	Bradford	8.0	426.0	N.T.	925/72	2	New well
78	Westmoreland	12-9-54	Bradford	231.0	4000.0	1330/68	N.T.	3	New well
79	Westmoreland	6-27-55	Bradford	260.0	260.0	800/5	900/90	3-1/2	New well
80	Westmoreland	7-25-55	Bradford	0.5	30.0	270/38	970/12	2	New well
81	Westmoreland	10-17-55	Bradford	1.0	55.5	700/68	800/48	2	New well
82	Westmoreland	5-14-56	Bradford	32.7	146.0	590/162	550/48	2	New well, shot
83	Westmoreland	2-16-56	Bradford	6.2	17.8	375/48	N.T.	2	Shot, old
84	Westmoreland	4-7-55	Bradford	51.9	381.0	785/144	615/48	2	New well
85	Westmoreland	7-23-55	Bradford	6.0	28.0	380/16	37/48	2	New well
86	Westmoreland	2-24-56	Eradford	7.9	150.0	330/96	500/16	3	New well
87	Westmoreland	4-17-56	Bradford	32.7	358.0	800/68	680/192		New well
88	Westmoreland	2-23-56	Bradford	12.5	162.0	1100/65	1170/240	3	New well
89	Westmoreland	1-5-56	Bradford	21.9	21.9	400/?	320/240		38 years old

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day Before	Open Flow Mcf./Day After	W.H.P./Hours Shut In Before	W.H.P./Hours Shut In After	Dia. Tubing In.	Remarks
90	Westmoreland	2-9-56	Bradford	30.6	293.6	490/20	360/240	2	37 years old
91	Westmoreland	8-24-55	Bradford	124.0	3000.0	575/43	1425/504	3	New well
92	Indiana	11-15-55	Bradford	8.4	178.0	300/18	905/18	3-1/2	9 years old
93	Indiana	6-19-56	Bradford	20.0	219.0	520/72	515/24		Old well
94	Indiana	4-26-56	Bradford	155.0	5800.0	1180/20	1235/20		New well
95	Indiana	1-17-56	Bradford	5.0	248.6	134/21	1280/60	3	New well
96	Allegheny	2-8-55	Speechley	34.6	76.0	250/92	262/60		Experimental
97	Westmoreland	8-19-55	Speechley	38.0	622.0	400/45	440/21	3	14 years old
98	Indiana	10-13-55	Speechley	14.0	200.0	825/44	850/16	3	14 years old
99	Westmoreland	10-5-55	Speechley	9.3	28.0	310/36	328/16	2	15 years old
100	Armstrong	7-28-55	Speechley	12.0	84.0	600/19	600/17	2	New well
101	Armstrong	9-23-55	Speechley	14.5	193.0	245/15	710/56	2	Shot
102	Armstrong	12-10-55	Speechley	3.5	28.2	466/69	352/48	2	Old well
103	Clarion	3-1-55	Speechley	5.5	14.0	710/72	N.T.		Old well
104	Butler	12-14-53	Speechley	44.5	188.0				Old well
105	Clarion	8-30-55	Speechley	3.0	20.0	500/72	600/24	2	Old well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day		W.H.P./Hours Shut In		Dia. Tubing In.	Remarks
				Before	After	Before	After		
106	Westmoreland	1-26-55	Speechley and Tiona	22.7	32.0	N.T.	N.T.		Old well
107	Westmoreland	6-22-55	Tiona	7.4	124.0	N.T.	925/288	3	New well
108	Armstrong	3-19-56	Tiona	15.0	80.0	250/44	390/1	2	Old well
109	Westmoreland	1-4-56	Tiona	18.0	112.8	N.T.	755/48	2	Old well
110	Armstrong	1-10-55	Tiona	52.0	22.0	820/72	N.T.		Old well
111	Jefferson	9-18-54	Tiona	30.0	60.0				Old well
112	Armstrong	7-27-54	3rd Sand	44.7	43.2	742/64	N.T.		Old well
113	Westmoreland	1-6-56	4th Sand	38.0	34.6	265/480	268/72	3	New well
114	Armstrong	7-27-54	4th Sand	23.0	43.0				Old well
115	Allegheny	9-27-54	4th Sand	11.8	4.5				Old well
116	Westmoreland	10-7-55	5th Sand	76.0	65.1	900/66	1000/16	3	New well
		10-26-55		52.0	48.0	1000/16	945/24		2 Fracs.
117	Westmoreland	4-25-56	5th Sand	15.5	143.0	820/42	960/168		New well
118	Armstrong	1-10-56	5th Sand	25.0	75.0	770/17	835/18		Old well
				53.0	160.0	N.T.	N.T.		2nd Frac.
119	Westmoreland	9-29-55	Bayard	12.0	62.0	600/13	935/48	2	New well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day		W.H.P./Hours Shut In		Dia. Tubing In.	Remarks
				Before	After	Before	After		
120	Armstrong	7-12-55	Bayard	10.0	19.7	940/72	940/72	2	New well
121	Westmoreland	11-10-54	Bayard	50.0	20.0	700/24	700/24	2	New well
122	Armstrong	9-10-55	Balltown	3.0	145.0	480/144	1000/14	2	New well
123	Armstrong	3-28-56	Balltown	7.0	155.0	525/20	950/48		New well
124	Indiana	10-6-55	Balltown	21.0	900.0	735/21	1310/65	2	New well
125	Indiana	12-27-55	Balltown	5.0	135.0	396/25	1060/72		New well
126	Armstrong	5-12-55	Sheffield	2.0	21.0	N.T.	910/16	3-1/2	Old well
				21.0	2.0	37/1	44/24		
127	Armstrong	2-2-55	Sheffield	6.0	13.0	440/15	720/16	2	New well
128	Armstrong	6-10-55	Sheffield	17.0	55.0	750/60	800/48	3	Old well
129	Armstrong	6-2-55	Sheffield	36.5	48.0	900/18	890/17	2	Old well
130	Armstrong	3-9-55	Sheffield	40.0	678.0	905/96	1100/14	2	Old well
131	Jefferson	12-15-55	Kane	72.0	365.0	1080/64	N.T.		Old well
					72.0				
132	Jefferson	6-8-55	Kane	19.8	22.9	N.T.	448/23		Old well
133	Jefferson	5-9-55	Kane	9.6	10.6	425/48	N.T.		Old well

Well No.	County	Date Fractured	Formation	Open Flow Mcf./Day		W.H.P./Hours Shut In		Dia. Tubing In.	Remarks
				Before	After	Before	After		
134	Armstrong	11-23-55	Kane	3.1	189.0	770/90	1150/18		Old well
135	Armstrong	4-4-56	Kane	8.0	188.1	850/44	1075/24		Old well
136	Indiana	7-18-55	Kane	12.0	27.0	415/72	460/48		Old well
137	Elk	9-24-55	Elk	7.0	None	700/36	None		Old well
138	Clearfield	11-25-55	Elk	1.7	70.0	N.T.	N.T.		Old well
139	Clearfield	5-11-56	Oriskany	300.00	750.0	3000/72	3400/72		New well
140	Clearfield	4-11-56	Oriskany	112.0	1300.0	2250/24	N.T.		New well
141	Clearfield	5-21-56	Oriskany	430.0	2903.0	3660/74	3580/42		New well
142	Indiana	9-2-55	Oriskany	10.0	475.0	500/40	3750/43		Old well
143	Indiana	5-12-55	Oriskany	220.0	160.0	4300/1	N.T.		Old well
144	Indiana	5-20-55	Oriskany	2.0	168.1		2650/48		Old well
145	Clearfield	7-6-55	Oriskany	Smell	3800.0		3600/24		Old well
146	Indiana	5-25-56	Oriskany	Smell	0.8		3550/48		Old well

APPENDIX II

FRACTURING DATA

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
1				6400	1800	10	3000	300	1900	
2										
3										
4										
5	47			5100			2300	224	2100	
6										
7	74		74	5700	2000	5	3000	228	2600	2-1/2
8										
9										
10	80	3	92	5600	2000	5	2200	257	2250	2
11	88	28	82	6500	2000	5	2000	237	2100	2
12	23	11	69	7000	2500	8	2300	265	2400	20
13	80	27	80	6300	2000	None	2000	210	1850	
14	32	7	73	5900	2500	5	2000	235	2450	3
15	19		22	6000	2500	5	2000	258	2250	2-1/2
16	75	28	104	6000	2000	None	2500	225	2200	2

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
17	39		52	6000	2000	None	2000	280	2250	2
18	46	7	48	7000	2700	None	2500	332	1900	2
19	52		55	7000	3000	None	3000	256	1800	2
20	33		70	5700	1600	10	2000	251	2100	3
21	20	2	125	4494	1600	10	1600	235	2100	5
22	61	16	56	4400	2000	10	2000	200	1800	3
23	58	17	182	4982	1600	10	2000	205	1960	1
24	80	63	73	7775	4000	30	2900	200	2000	3
25	40	31	74	6000	2000	5	2600	244	2000	2
26	51		100	7000	4200	None	4800	211	2600	3
27	177	22	163	5670	1600	10	2000	246	1950	2-1/2
28	87	28	62	7000	2800	5	2000	278	2600	3
29	50	5	64	6426	3000	10	5500	226	2500	1-1/2
30										
31	Not available									
32	117	50	46		14100	336	1750		2000	
33	81	81	197		1600	None	2000		1800	
34	16	16	19			10	2000		2800	

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
35	28	6	60	8000	3000	10	5300	222	2100	1-1/2
36	19	7	18	7000	3500	420	6500	215	2700	3-1/2
37	46	25	45	5200	3500	420	4300	227	2700	2
38	25		25	5800	3500	5	4000	213	3000	2-1/2
39	37	7	47	6000			2000	242	2100	
40	8		50	8500	2000	None	2000	274	2200	3
41	65		69	6000			2000	252	2400	
42	128	20	47	10080	3000	None	4100	214	1900	2
					3000	None	2800	180	2500	3
43	45	40	49	7250	4000	None	5500	200	2600	3
44	69	28	100	5100	1600	10	2000	144	2400	2
45	15		21	6300	3000	None	3500	336	2250	1
46	86	20	86	5100	1600	5	2000	128	1900	4
47	33	21	39	1600	1600	5	2000	165	2100	1-1/2
48	20		36	7000	3000	5	4000	320	2500	1
49	38	11	58	7000	2000	5	3000	173	2200	1-1/2
50	34		38	6500	2000	None	3000	252	1750	2
51	30	18	123	5000	2000	10	3000	250	2200	2
52	42	10	47	7200	4000	5	3000	141	2200	1-1/2

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
53	39	8	116	4400	1600	5	2000	165	2000	3
54	40	34	51	9930	3000	None	4500	214	2100	2
					3000	None	3000	214	2300	1-1/2
55	42	14	57	8100	3200	5	4000	190	2700	1
56	76	20	84	6000	2000	5	2000	285	1900	2
57	42	19	42	6000	2500	None	2500	212	2000	2
58	60	50	81	6000	2500	None	2500	325	2500	2
59	59	12	58	6000	2000	None	2500	250	2000	2
60	20	6	58	7300	2000	5	2000	309	2200	2
61	74	27	45	6000	2000	None	2000	243	2200	2
62	37	3	36	6000	2000	5	2000	270	2150	1-1/2
63	43	28	43	6000	2000	None	2000	252	1850	2
64	47	11	47	6000	1600	2000	2100	205	2300	20
65	50	14	67	7000	2600	5	3000	275	2400	
66	57	6	56	6700	3000	5	3300	294	2100	4
67	43	32	45	7000	3000	5	2500	138	2350	2
68	32		33	7000	3000	5	2600	237	2000	2
69	59	16	95	7000	2500	5	3000	294	1900	2
70	46		45	7000	2500	10	3000		2200	

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
71	60		62	7000	2500	None		271	2000	2
72										
73	43	14	47	7000	3000	None	3000	287	2000	2
74										
75										
76		10		2000	2000	5	2000	188	2700	2-1/2
77	18	18	53	2940	2000	None	2000	189	3500	1
78	11	11	11	8000	2400	None	3000	126	2200	
79	17	13	17	6678	3000	5	3000		3600	4
80	30	10	25	5000	2000		2000		2850	20
81	25	25	35	3710	1400	5	2000	100	3000	2-1/2
82	9	7	47	5000	2000	5	2500	205	2800	1-1/2
83	30	10	60	2000	2000	10	2000	175	2500	2
84	10	6	12	5800	1600	10	1600	128	2650	5
85	7	7	33	4400	2000	5	2400	160	2500	5
86	25	16	28	8200	3000	5	3600	284	2100	2
87	30	19	58	7100			4000	219	2200	
88	28	8	48	9000	4000	5	4000	204	2600	2
89	14	14	13	6000			3000	120	5800	

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
90	20	15	27	6400	3000	None	3000	294	3000	2
91	32	6	21	6300	1800	5	2000		2250	5
92	21	6	37	6000	2000	10	2500	300	2100	10
93	54	12	32	6000			2000	211	2400	
94										
95	24	5	151	7500	1500	None	2000	178	2800	2
	34	1			1500	None	2000	178	3000	2
96										
97	51	20	49	6000	2000	5	2000	253	2400	3-1/2
98	55	46	47	5800	2500	5	2400	178	2700	2
99	48		67	5500	2500		2200	107	3400	3
100		4	35	4000	1600	5	2000	101	2500	5
101	26	21	94	4100			2000	140	2750	2
102	20	15	16	2900			800	225	2000	9
103	30		30	2450			1000	220	2500	
104	27		26	6000	1340		1100		2450	
105	18	4	16	5000	2000	10	2000	225	2250	3
106										
107	18	12	11	5880	3000	5	2400	325	2900	2
108	26	8	38	4500	2000	None	2000	210	2350	3

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
109	20	8	41	5000	2000	5	300	220	2500	2
110	11	10	12	4500			2000	82	2500	
111	20	Crude Oil	17	4200	400		2400		2000	
112	7	Diesel Oil					1200	336	3300	
113	21		21	3000	3000	None	3000	190	6400	5 hrs.
114	15		7						3700	
115		Diesel Oil	98	5900	2000				2450	
116	36	26	31	3500	2000	5	3000	178	3300	2
				4500	2000	None	1700	232	4400	3
117	18	3	9	4500			2000	232	2150	
118	36	8	33	5468			2000	115	2300	
119		2		5000			2000		4200	
120	20	11	55	5000	1428		2000		None	
121	12	2		3800		2100	1500		4500	
122	20	3	24	5000	2000	10	3000	189	2600	3
123	30	12	24	5880			2000	212	2150	
124	23		83	4500	1600	5	1500	80	2550	3
125	26	5	51	3700	1600	5	2000	140	2850	4
126	31		31	6000	2000	10	3000	210	2600	3
127	48	25	63	4500	1600	None	2000	84	2600	2-1/2

Well No.	Formation Thickness Feet	Prod. Zone Ft.	Fracture Zone Ft.	Kerosene Gals.	Gel Gals.	Gel Breaker Gals.	Sand Used Lbs.	Injection Rate Gals./Min.	Break Down Pressure Lbs./Sq.In.	Break Down Time Min.
128	33		87	6300	3000	5	3100	239	2500	2-1/2
129	22	20	21	6000	946	400		182	2800	
130	30		40	5880	1600	1000	2000	133	2500	4
131	22	17	22	6200			4500	233	3000	
132	18		22	6500			3500	221	3900	
133	7			6700			4100	150	3800	
134	13	4	21	4662			3000	168	3250	
135	9	2	17	4300			2600	158	2700	
136	19		22	4400			2000	100	2600	
137	34	22	27	3000			2000	158	3250	
138	30	2	74	4900			2400	196	3400	
139	90	12	177	4000			3500	152	4650	38
140	100	2	165	7140			3000	135	4150	37
141	93		165	4000			4500	231	4500	11
142		30	185	7476			1700	102	4500	
143	114	46	151						4050	
144	92	15	89	8400			6200	142	3800	
145	241	5	252	7500			3200	108	4000	
146	129		153	8100			4100	172	4500	

APPENDIX III

MONTHLY PRODUCTION IN MM CU. FT. BEFORE AND AFTER FRACTURING

Well No.					Months Before Fracturing							
	12	11	10	9	8	7	6	5	4	3	2	1
					Months After Fracturing							
	1	2	3	4	5	6	7	8	9	10	11	12
1											0.23	0.42
	4.47	4.93	5.27	3.86	4.32	2.86	3.46	2.93	3.16	2.53	2.44	
2										0.32	0.21	0.21
	2.62	2.49	1.55	2.08	1.52	1.67	1.40	1.68	1.37	1.36		
3								0.27	0.45	0.45	0.50	0.30
	5.14	6.66	4.56	4.87	2.56	3.69	3.16	2.92	2.01	1.91		
4										0.57	0.42	0.44
	7.12	3.27	3.52	2.55	2.61	2.36	2.57	1.98	1.97			
5								0.85	0.86	0.80	0.91	1.67
	5.49	3.61	3.92	2.51	2.91	2.61	2.86	2.46	2.12			
6									1.96	2.14	2.57	3.07
	2.47	2.92	4.10	3.23	3.46	2.92	3.01	2.06	2.26			
7									0.47	0.45	0.43	0.65
	0.56	0.82	0.68	0.91	1.06	0.85	0.85					
8								Open flow monthly basis .390/month				
	6.11	6.91	4.86	4.53	3.46	3.87	2.82	2.92	2.53	2.79	2.17	2.09
9												0.60
	5.06	4.81	4.38	3.77	3.56	2.86	3.36	2.48	2.87	2.38	2.78	2.31
10								0.35	0.33	0.33	0.30	0.16
	1.72	2.65	1.73	1.82	1.48	1.66	1.29	1.27				
11							0.25	0.25	0.25	0.25	0.22	0.16
	5.96	1.97	2.55	2.15	2.62	1.86	1.77					
12						0.88	0.87	0.82	0.80	0.68	0.72	0.18
	1.05	1.37	1.26	1.36	1.00	0.92	1.00					
13					0.46	0.41	0.43	0.43	0.37	0.43	0.48	0.35
	5.43	4.54	3.75	3.18	2.16	2.14						
14												0.98
	1.16	1.71	1.27	1.23	1.45	1.01	1.00					
15							New well, open flow monthly basis .77/month					
	3.30	6.17	4.26	4.30	3.00	2.62						

					Months Before Fracturing							
	12	11	10	9	8	7	6	5	4	3	2	1
					Months After Fracturing							
Well No.	1	2	3	4	5	6	7	8	9	10	11	12
16				0.41	0.35	0.41	0.44	0.40	0.34	0.27	0.02	0.01
	3.57	4.46	4.72	3.26	3.05							
17		0.08	0.08	0.10	0.12	0.08	0.09	0.09	0.05	0.33	0.18	0.17
	2.42	3.49	2.97	3.28								
18											New well	
	1.55	3.91	3.77	3.83								
19											New well	
	8.04	5.57										
20					1.11	1.07	1.42	1.16	1.58	1.53	7.54	1.55
	3.56	3.62	3.87	2.86	3.36	2.71	2.66	2.62	3.28			
21						0.96	0.91	1.23	0.72	0.90	0.85	0.63
	1.68	2.37	1.73	1.56	1.81	1.51	1.49	1.77	1.54	1.53		
22						0.76	0.74	0.98	0.87	1.13	0.82	1.13
	6.26	3.62	3.36	3.51	2.27	Wells 22 and 23 on same meter fractured						
23	5.61	3.91	3.16	2.97	3.67	5 months apart						
24						0.88	0.86	1.12	0.86	0.00	0.36	0.09
	2.38	4.76	4.38	4.72	3.37	3.56	2.67	2.65	2.67	3.28		
25			0.28	0.26	0.35	0.27	0.30	0.38	0.30	0.30	0.38	0.11
	2.53	1.91	1.87	2.49	1.26	2.01						
26			0.26	0.25	0.30	0.28	0.33	0.28	0.28	0.26	0.47	0.00
	0.00	0.001	0.001	0.01	0.01	0.01	0.07					
27	Production from June 1949 to June 1955; High 1.821, Low 0.975/month											
	7.68	6.47	6.41	4.32	4.01	4.56	3.31	3.90	2.97	3.09	3.11	3.96
28					0.61	0.56	0.70	0.62	0.79	0.61	0.62	0.50
	1.46	3.17	3.91	2.87	3.57	2.46	2.41	2.37	2.86			
29						1.26	1.15	1.52	1.27	1.11	1.32	0.96
	6.66	6.53	5.48	5.71	4.01	3.52	3.87	4.01	3.22	10.29		
30	Well almost ceased to flow, would have been abandoned. Fractured 8-14-54											
	1.93	3.75	2.52	2.43	2.61	2.02	1.76	1.82	2.16	1.56	1.93	1.55
31							Open flow monthly basis 0.245/month					
	3.56	3.49	3.36	2.77	3.30	2.45	2.84	2.21	2.09	2.46	1.81	1.72
32							Open flow, monthly basis 0.355/month					
	3.26	2.53	2.96	2.72	3.21	2.16	2.17	2.61	1.89	2.46	1.76	1.75
33							Open flow, monthly basis 0.361/month					
	2.83	1.73	1.92	1.34	1.31	1.52	1.17	1.06	1.26	0.98	0.87	0.86

Well No.	Months Before Fracturing: 12	11	10	9	8	7	6	5	4	3	2	1
	Months After Fracturing: 1	2	3	4	5	6	7	8	9	10	11	12
34							Open flow monthly basis 0.365/month					
	0.26	0.37	1.20	2.41	0.42	0.45	0.38	0.34	0.43	0.33	0.30	
35					New well, open flow, monthly basis 0.180/month							
	1.63	2.46	1.62	1.76	1.31	1.22	1.32	0.97	0.96	1.17	0.92	0.87
36					New well, open flow, monthly basis 0.840/month							
	2.24	2.37	2.32	1.63	1.38	1.64	1.18	1.09	1.26	1.32	1.19	
37					New well, open flow, monthly basis 0.600/month							
	3.66	5.57	3.78	4.01	2.26	2.85	2.56	2.49	3.22	2.03	2.72	
38					New well, open flow, monthly basis 0.150/month							
	0.08	0.06	0.02	0.02	0.03	0.29	0.29					
49										1.95	1.92	1.27
	3.91	5.82										
50	0.42	0.36	0.27	0.45	0.49	0.60	0.48	0.48	0.57	0.50	0.45	0.50
	1.67	1.87	1.37	1.61								
51								0.41	0.48	0.71	0.56	0.61
	3.11	3.09	2.17	2.01	2.25	1.62	1.57	1.88	1.47	1.42	1.76	
64									0.43	0.27	0.38	0.33
	4.43	4.03	4.44	3.01	2.49	2.61	3.11					
65						0.15	0.08	0.05	0.03	0.05	0.04	0.02
	6.59	4.27	4.25	4.31	2.67	2.48	2.93					
66					0.61	0.65	0.61	0.44	0.49	0.42	0.52	0.37
	18.53	11.61	7.80	6.06	5.61	6.69						
67										0.32	0.40	0.19
	1.27	3.82	2.81	2.46	1.86	2.20						
68					New well, open flow, monthly basis 0.375/month							
	3.02	3.59	3.32	3.31	3.87							
69				0.57	0.51	0.56	0.42	0.51	0.51	0.55	0.53	0.47
	3.17	2.66	2.26	2.01	2.44							
70			0.98	0.98	1.26	1.02	1.03	1.05	1.05	1.31	1.01	1.03
	7.12	5.37	4.57	5.27								
71										New well		
	7.95	5.23	5.51									
73										New well		
	4.29	6.44										

Well No.	Months Before Fracturing: 12	11	10	9	8	7	6	5	4	3	2	1
	Months After Fracturing: 1	2	3	4	5	6	7	8	9	10	11	12
76										0.41	0.36	0.23
	5.47	4.93	4.51	4.42	5.23	3.73	3.61					
77						New well, open flow, monthly basis 0.245/month						
	4.87	3.42	3.01	2.30	1.72	2.67	1.92	1.90	1.62	1.87	1.61	1.43
78						New well, open flow, monthly basis 6.91/month						
	2.36	9.61	8.51	8.52	9.48	7.52	6.71	7.22	6.01	4.82	3.72	3.05
79	New well fractured after 6 months production						8.77	12.20	15.23	17.59	19.47	14.35
	13.05	14.91	11.56	8.82	5.31	3.90	5.02	6.89	7.42	5.97	2.37	
80						New well, open flow, monthly basis 0.02/month						
	0.28	0.51	0.45	0.40	0.32	0.34	0.31	0.30	0.31	0.32		
81										New well		
	0.08	0.26	0.22	0.19	0.18	0.21						
83											0.18	0.03
	0.43	0.35	0.42									
91						New well, open flow, monthly basis 1.51/month						
	7.15	18.22	11.32	8.42	6.31	6.02	6.71					
92			0.23	0.24	0.24	0.25	0.22	0.25	0.10	0.25	0.20	0.20
	1.51	1.91	1.32	1.20								
96												1.00
	0.52	0.81	0.64	0.83	0.71	0.75	0.56	0.49	0.50	0.47	0.42	0.55
97							1.46	1.13	1.18	1.17	1.17	1.36
	6.61	4.93	5.20	3.48	3.16	3.35	2.81					
98								Open flow, monthly basis 0.410/month				
	6.19	5.67	5.28	5.68	4.56							
99					0.50	0.46	0.50	0.50	0.45	0.46	0.50	0.50
	0.08	0.22	0.35	0.45	0.40							
105					1.73	3.56	2.05	2.36	2.70	2.38	2.41	2.92
	2.46	2.94	2.47	2.82	2.41	2.37	2.86	2.49	2.48			
106								Open flow, monthly basis 0.27/month				
	0.27	0.32	0.39	0.91	0.38	0.38	0.38	0.37	0.36	0.32	0.36	
107						New well, open flow, monthly basis 0.21/month						
	1.35	1.70	1.60	1.58	1.48	1.25	1.22	1.42				

	Months Before Fracturing											
	12	11	10	9	8	7	6	5	4	3	2	1
	Months After Fracturing											
Well No.	1	2	3	4	5	6	7	8	9	10	11	12
108											0.03	0.01
	1.02	0.66										
116									New well			
	0.73	1.23	1.36	1.76								
119						0.33	1.45	1.23	1.51	1.08	1.01	1.17
	1.16	2.57	2.12	2.61	2.0	2.01	2.06	2.62	1.92			
122							New well, open flow, monthly basis 0.090/month					
	1.42	1.11	0.67	0.63	0.65	0.72	0.57	0.72				
126										0.67	0.48	0.45
	0.38	0.60	0.08	0.15	0.00	0.05	0.06					
							New well, open flow, monthly basis 0.18/month					
	0.22	0.32	0.31	0.38	0.33	0.45	0.34	0.40	0.56	0.41	0.44	0.53
128								Open flow, monthly basis .510/month				
	0.60	2.26	1.78	1.66	1.53	1.43	1.46	1.82	1.90	1.96	1.89	
								Open flow, monthly basis 1.20/month				
130	5.82	5.18	4.27	9.96	7.52	5.64	7.93	5.93	5.05	4.72	4.73	4.20

APPENDIX IV

FRACTURING COSTS

Well No.	Service Co. Charges	Cost of Kerosene	Cost of Surveys	Cost of Tubing	Fracturing Labor	Clean Out Labor	Other Costs	Total Cost
2	1300.68	662.31	475.39	3691.54	910.14	2830.17	1973.64	11,843.87
5	1207.09	617.16	327.25	3209.40	1351.67	33.19	952.78	7,698.54
7	1536.92	440.56		1955.90	6130.30	2605.69	5028.15	17,697.52
8	1039.82	418.70		2925.72	506.55		1286.86	6,177.65
9	1403.98	373.08		994.09	4510.81		554.08	7,836.04
10	1190.24	477.10	353.64	2995.34	2036.27	1019.61	797.43	8,869.63
11	1192.72	413.00	323.02	4440.29	3338.38	1968.58	2059.93	13,735.92
12	1167.67	980.00	294.19	2588.30	3578.86	525.90	2040.72	11,175.64
13	1178.35	924.50	345.42	3255.93	1511.42	515.37	1778.84	9,509.83
14	1145.07	840.00		5889.04	262.13			8,136.24
15	1164.32	840.00		6487.23	351.19		941.42	9,784.16
16	848.50	826.30	334.56	3634.47	4688.91	250.08	1768.99	12,351.81
17	1117.47	760.00	352.84	3039.96	1984.37	377.46	1413.52	9,045.62
18	994.23	140.56		2821.52	311.18		708.30	4,925.79
19	929.50	710.77		2687.82	254.09		1522.73	6,104.91
40	940.72	704.50		3169.64	1633.77	455.10	1302.44	8,206.17

Well No.	Service Co. Charges	Cost of Kerosene	Cost of Surveys	Cost of Tubing	Fracturing Labor	Clean Out Labor	Other Costs	Total Cost
41	874.90	1108.00		2898.92	2886.11	854.98	1182.74	9,805.65
57	1111.62	917.15	318.96	825.68	7789.59	560.11	1543.75	13,066.86
58	1166.11	630.00	318.14	3268.38	1389.11	559.58	1092.46	8,423.78
59	1171.63	632.80	8.48	3035.45	1927.01	307.76	550.53	7,633.66
61	1255.98	812.00		2912.92	584.80		1261.15	6,826.85
62	1185.71	578.85	316.40	1872.66	3072.96	198.64	425.29	7,650.51
63	900.55	56.00	283.40	596.99	3288.80	32.45	1569.90	6,728.09
64	984.43	490.00	23.41		292.98		2690.92	4,481.74
65	1035.16	714.00		372.12	2941.74	167.26	1338.32	6,568.60
66	1019.07	830.75		2960.86	711.75		1222.53	6,744.96
69	1206.11	484.00	310.10	1462.79	4800.54	1471.84	4592.55	14,327.93
82	1621.78	272.00		3072.46	10292.27	3021.21	7676.62	25,956.34
84	1161.82	693.60		7046.38	360.40		2439.10	11,701.30
85	1165.00	588.00	351.20	1212.88	2411.04	114.99	737.82	6,580.93
96	1225.95	960.22	230.16		1906.48		917.63	5,240.44
98	1173.50	780.37	510.54	2783.29	3136.42	193.45	2161.65	10,739.22

Well No.	Service Co. Charges	Cost of Kerosene	Cost of Surveys	Cost of Tubing	Fracturing Labor	Clean Out Labor	Other Costs	Total Cost
99	1189.04	504.00	538.09	1343.77	3559.06	57.81	1885.44	9,077.21
106	1464.00	785.00		1239.07	1515.54		1835.70	6,839.31
107	1560.40	615.00	13.21	4736.01	641.10		2258.98	9,824.70
113	1356.15	726.50		2439.28	993.42		896.13	6,411.48
116	1154.08	504.00		2083.30	842.56	1008.00	1235.50	6,827.44

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