REPORT

OF

PROFESSOR DANIEL M. BASS, JR.

Registered Professional Petroleum Engineer

INDEX

EXPERIENCE RESUME

DANIEL M. BASS, JR.

EXPERIENCE RESUME

Educational

Received B.S. in Petroleum Engineering from Louisiana State University
Received M.S. in Petroleum Engineering from Texas A and M College
Receiving Ph.D. in Petroleum Engineering from Texas A and M College

Industrial

Field Engineer District Reservoir Eng.	Magnolia Petroleum Co. Approx. 3 years
Research Engineer	Texas Pet. Research Committee Approx. 2-1/2 years
Professor in Pet. Eng.	Texas A and M College Approx. 9 years

Taught: (1) Fluid Transmission
(2) Surface Handling of Petroleum
(3) Basic and Advanced Reservoir Eng.

Professor and Head of Pet. Eng. Department	Colorado School of Mines Approx. 2 years

Teach: (1) Drilling and Well Completion
(2) Basic and Advanced Res. Eng.

Consulting

Reservoir Evaluation
(1) Regulatory hearing.
(2) Oil and Gas studies
(3) Application of Digital Computers to oil and gas reservoirs and surface production systems.
(4) Economic analysis
(5) Special Industry schools in Petroleum Reservoir Engineering

Research Work

(1) Application of Digital Computers in the Petroleum Industry
(2) Effect of Fluid and Rock Properties on Water Displacement
(3) Volatile crude oil systems
(4) Flooding patterns
(5) Fracture Propping Agents

DANIEL M. BASS, JR.

EXPERIENCE RESUME

Publications and Presentations

(1) "The Petroleum Engineer; Conservation, The Public and the Profession", Presented to Denver SPE Section, 1962.

(2) "Estimating Secondary Reserves", Presented and Published by Regional SPE - Billings, Montana, 1962.

(3) "Evaluation of Volatile Oil Reservoirs", Presented and Published - 13th Oil Recovery Conference - 1961.

(4) Contributed to "Petroleum Production Handbook", Vol. II, edited by Tom Frick, published by McGraw-Hill, 1962.

(5) "Petroleum Reservoir Engineering-Physical Properties", co-author - book published by McGraw-Hill, 1960.

(6) "Experimental Waterflooding Recoveries Above and Below the Bubble Point", AIME Trans. 1956.

(7) "Predicting Reservoir Performance", Petroleum Eng., June, 1955.

DEVELOPMENT PROGRAM

DEVELOPMENT PROGRAM

I. Mr. Blackman requested that I speak to the following question:

"Please refer to the exhibit attached to the bulletin board which has been marked for identification as PCA Exhibit No. . It is a plat which shows Section 17, Township 20 South, Range 30 East, New Mexico Principal Meridian, on which the contour lines on the approximate top of the Devonian as depicted by Exhibit No. presented by Pan American Petroleum Corporation in this hearing have been extended.

"Will you kindly make these assumptions with respect to that exhibit:

"A. There exists at the location shown on that exhibit a closed Pennsylvanian or Devonian structure below 9,000 feet, having the configuration shown on said exhibit which is inhabited with oil, or with oil and gas to the third contour line.

"B. There are no surface terrain problems, surface relief being nominal.

"C. The reservoir consists of oil having a solution gas drive.

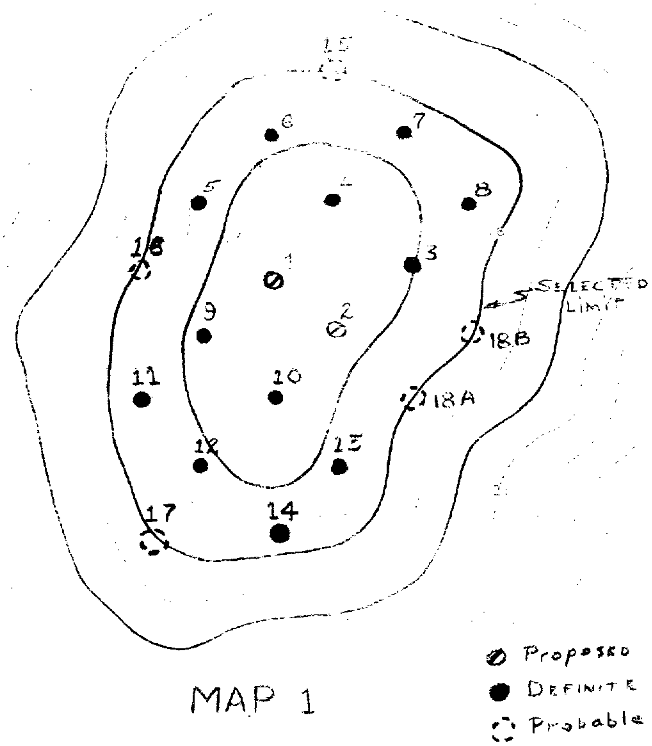
"D. The reservoir characteristics and conditions are the approximate average of what might be expected to be found in this location in Southeastern New Mexico.

"Assume that 80-acre spacing would be approved if an oil or oil and gas reservoir were to be discovered at this location and depth.

"On the basis of the assumptions which I have enumerated, will you kindly indicate on PCA Exhibit No. an ideal development program, to recover the maximum amount of petroleum products from the reservoir. Please begin with the proposed location near Barber Well 4J and number each well location without regard to order in which the wells might be drilled. In this connection, please consider the New Mexico statute governing waste, which reads as follows: 'As used in this act the term "waste," in addition to its ordinary meaning, shall include: (a) "Underground waste" as those words are generally understood in the oil and gas business, and in any event to embrace the inefficient, excessive, or improper, use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating, or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool ...'

"When you have indicated the ideal drilling and development program on PCA Exhibit No.   , please comment on the pattern for the solution gas drive and also comment upon such variations as you might recommend in the event the reservoir has a water drive or a gas cap drive."

You have asked me to indicate an ideal drilling and development program on 80-acre spacing for a Pennsylvanian or Devonian oil or oil and gas reservoir which occupies a producing structure which might be expected under average conditions in Southeastern New Mexico. The structure is assumed to be in the location and to have the configuration as shown on PCA Exhibit No.   , to be inhabited with oil or oil and gas in the area inside of the closure


15
6
7
5
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8
16
1
3
SELECTED LIMIT
9
2
18B
11
10
18A
12
13
17
14
Proposed
DEFINITE
Probable

MAP 1

depicted by the third closed contour line and to have a gas solution drive. Attached to the facing page hereof is a photocopy of a map which is designated Map No. 1 - T 20S, R 30E, N.M.P.M., which shows the same area and drilling and development program.

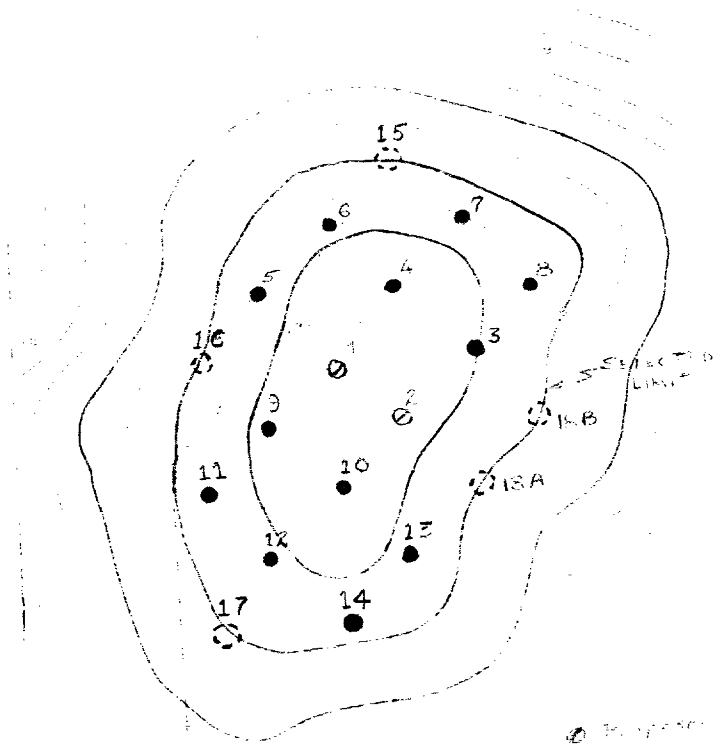
The wells on this map marked 1 and 2 are the wells represented by the present drilling application of Pan American Petroleum Corporation. The wells with the dark spots would be definite wells within the structure and the wells with the broken circles represent possible additional wells. Of course, knowing the structure as it is seen here, it is noted that I have not included any uncommercial wells, of which, one or two would probably be drilled in order to define the structure. The wells marked with the broken circles would all be potential wells and, in all probability, would be drilled during the development program. Thus it is seen that there are fourteen definite wells and four potential wells. Thus, the possibility of one or two non-commercial wells would indicate a potential between seventeen and twenty wells in order to completely define the oil accumulation within the structure.

The sequence of drilling these wells is at the present time difficult to define. The exact sequence of course would depend on what was found during the drilling of the initial well. If this well were on top of the structure, as indicated, then it would be necessary to drill down-dip, flank wells in order to determine the limits of the hydrocarbon accumulation. If, as in most cases, the initial well were not exactly on top of the structure, and dip meter surveys and other information obtained during the drilling of the well indicated that the structure top were away from the present well, then the next well drilled would be an effort to define the structural top. It is nearly impossible to define an exact drilling program until after the first well is drilled into the accumulation.

This 80 acre development program would adequately produce the reservoir if it were of a solution gas drive type energy.

If the reservoir were of gas-cap type energy in which it was necessary to permit the advance of the gas cap in order to obtain maximum conservation then it would be necessary to drill essentially all of the wells which are denoted by a broken circle. This type drive would increase the number of wells which would be required for adequate depletion from fourteen to nineteen. In this case, considering that two non-commercial wells would be drilled, a gas-cap energy ~~c~~source would result in the drilling of the maximum number of wells on the structure, twenty-one wells.

Should a water drive energy source be prevalent then it would be unnecessary to drill the wells which are indicated by the broken circles and well No. 14. Probably two of the wells indicated by a broken circle would be drilled during the development program and probably one non-commerical well would be drilled in defining the structure. Thus, a water drive energy source would require the drilling of the minimum number of wells on the structure, approximately sixteen wells.



MAP 2

The 80 acre spacing as indicated on Map 1 would probably be required for any oil accumulation which is found.

II. You have requested that I comment on the following question "What would be the effect on such an oil or oil and gas accumulation if the structure were divided as I will now indicate by a red line designated "A" at one end and "B" at the other end on PCA Exhibit No.   and only those wells which are situated below or southerly of the red line A-B were drilled and produced for an initial period of fifteen years, there being no wells drilled or produced above or northerly of the red line A-B for such initial 15-year period."

Map No. 2, facing this page, indicates a dashed line A-B which is equivalent to the red line, also marked A-B, on PCA Exhibit No. \ . The effect on conservation of the natural resources within such an accumulation would be dependent upon the mode of operation of the developer and on the energy source within the oil accumulation itself. In order to properly answer this question it will be necessary to stipulate a behavior for at least three distinct types of energy sources. If the reservoir were a solution gas, gas cap drive or a water drive reservoir, one would expect a different performance; hence, each of these type drives will be discussed separately.

Solution Gas Drive

If the reservoir is a solution gas drive type then the recovery mechanism would be that of displacing the oil by the evolution of gas from within the oil. This is probably one of the least efficient drive mechanisms available if it is not aided in some fashion by gravity segragation and conversion to a secondary gas cap drive. It is entirely possible that a restriction of development to one segment of the reservoir would create conditions such that a secondary gas cap would be formed at the top of the structure. In any case, this restrictive development would be detrimental to the conservation of the petroleum within the structure. Such a development would force the oil and its associated gas in the undeveloped area to migrate around or over the structure in order that it might be produced. The force of gravity would work against migration over the top of the structure and would, in effect, leave oil in the lower portions of the structure and gas would migrate to the upper section. During the depletion of the developed portions the operator would be unable to produce his wells in a fashion which would prevent the pressure depletion and the migration of the gas from the area in which no drilling had occurred. During this depletion stage the operator would be producing from wells, according to your red line, in approximately 38 percent of the volume of the reservoir, leaving approximately 62 percent undeveloped. Within this 62 percent of the total structure the operator would probably recover some 25 to 50 percent of the oil that he would recover were he able to fully develop that region. Thus the operator and the state would loose between 30 and 45 percent of the oil within the structure that would normally be recovered by a solution gas drive mechanism under full development.

The granting of permission to drill and develop this region fifteen years after the development of the southernly end of the structure would in all probability not be economic from the standpoint of primary recovery. During the pressure depletion in the southernly part of the structure, the energy for movement of the oil in the northern part of the structure probably would have been dissipated. Thus, even drilling within the structure where no previous production had occurred would not yield oil in the same quantities that were obtained during the initial development on the southernly end of the structure. To adequately remove the oil from this previously undeveloped area of the structure would require that the operator install a supplementary energy source, gas injection or water injection, to supply energy for movement of the oil from within the formation to the loci of the wells. Supplementation of the natural energy would be costly and its initiation would depend on whether the producer could recover the required investment from the recoverable oil that remained in the formation.

In the outside case, in which a secondary gas cap is formed at the top of the structure, the operator could conserve some of the energy by not producing the secondary gas cap. In so doing, he would still not recover by primary means any additional oil and in all probability would recover less from the undeveloped side of this structure. This would mean that a restrictive development program would cause the producer to leave approximately 45 percent of the recoverable oil within the ground. The only advantage of the secondary gas cap is that after the end of the fifteen year period there is the probability that some of the oil in the undeveloped region could be recovered by means of expansion of this gas cap. Thus, the operator would be conserving part of the natural energy within the reservoir by letting gas accumulate at the top of the structure and later permitting this gas to expand and displace oil to the wells. The additional recovery which might be obtained during this second development program would be dependent upon the magnitude and size of the secondary gas cap. If the gas cap is small then little additional oil would be realized because the energy source would be insufficient to adequately deplete the undeveloped portion. If this gas cap is large and if it has been possible to maintain the pressure somewhere in the neighborhood of one-half of the original pressure, it would be possible to reduce the loss of this stage development program from 45 percent to some 15 or 20 percent.

It is fairly apparent that regardless of the mechanism which might be involved in the solution gas drive depletion of such a partially developed structure, some loss of petroleum would occur. The magnitude of this loss would be in the neighborhood of 15 percent for very favorable conditions and 45 percent for normal conditions.

Gas Cap Drive

If the structure had a hydrocarbon accumulation of the size shown in Map 2 and part of this accumulation were gas, to say the first contour, then the southernly area in which development is to be permitted would encompass part of the oil zone and part of the gas zone. This gas zone represents a concentrated source of energy which, if permitted to expand through the oil zone, acts as a more efficient recovery mechanism than solution gas alone. In a partial development, such as you have indicated, the presence of the gas cap can be a disadvantage during the depletion stage of the developed area. The gas is very mobile, it moves much more readily within the pore structure than does oil. Gas also transmits pressure changes much more readily than does a similar section of the reservoir containing oil. Hence, at any given time, the pressure within the gas zone would essentially be constant value over a large part of the original reservoir filled with gas. Thus the pressure in the undepleted area would have ample opportunity to decline along with the decline in gas pressure. Also, partial development would tend to concentrate the expenditure of this gas cap energy in only a fraction of the oil saturated zone. The irregular decline in pressure would result in a tilting of the gas zone as depletion occurred. This tilting would cause the developed portion of the reservoir to be swept by gas with very little enlargment of the gas cap in the undeveloped region. To adequately deplete the section that is developed it would be necessary to produce a good portion of the original gas cap gas from the wells within the oil zone. The presence of the gas cap would retard the migration of oil from the undeveloped portion into the developed portion because of the greater ability of the gas to advance into the producing region. Thus, the initial loss due to partial development would be in the neighborhood of 35 to 40 percent of the normal recoverable oil. Development of this region after a delay of 15 years would recover some of the remaining oil. Advancing gas from the gas cap would not be as efficient a displacing agent after the delay because of the effect declining pressure has on the properties of the oil and the reduced ability of the operator to obtain maximum sweep with the advancing gas. If the pressure had been depleted to a very low level, the economics of developing this region would not be as goodas if it had been developed along with the other section because of the energy content of the remaining fluids. Thus, even under the most ideal conditions, the delayed development results in a total loss within the structure on the order of 15 percent of that which would be recovered had the structure been developed uniformly.

In all probability it would be necessary to supplement the energy within the reservoir with either gas or water injection which alters the economics and increases the cost. Regardless of the operators practice of production, a delay of 15 years in full development would result in a loss of between 15 and 40 percent of that oil which would be recoverable under a standard, uniform development program.

Water Drive

If the oil accumulation within the indicated structure has a strong water drive around the periphery and if development were restricted to the southernly part enclosed by dashed-line A-B on Map 2 it would be necessary for the operator to concentrate his production in the upper segment of the structure in order to partially deplete the lower part of the undeveloped portion of the reservoir.

Under these conditions, the production from the wells adjacent to the dashed line could be controlled so that it would be possible to partially pressure deplete and cause water invasion into the area in which no development had been permitted. Concentrating the production at the top of the structure would cause water to advance within the undeveloped region but would also cause extreme pressure losses around these wells and might endanger the completion of the well and reduce the recovery efficiency ofthe water drive mechanism. The advance of water in the undrilled region would not occur as rapid as the water advanced within the developed region because of the concentration of production in the developed area. Thus, the pressure distribution within the structure would have a tendency to cause water to migrate in a tongue like fashion into the developed area and a short advance in the undeveloped region. This manner of water advance would create a region near the top of the structure which would contain significant quantities of oil at the time the existing wells were invaded by water and forced into a non-commercial category.

The loss in such a situation cannot be ascertained with a finite degree of accuracy because of the dependency of water invading the undeveloped region on the exact well locations, their relative production rates and the volumetric efficiency of water as a displacing agent. A fair estimate of the loss of recoverable oil would be in the neighborhood of 20 to 25 percent. If this region were developed after a period of fifteen years it would be a rather costly development program because the position to which water had advanced in the undeveloped region would be unknown. Thus, wells would be drilled which were un-economical to operate and for depletion purposes un-necessary. The recovery from this region would depend on the magnitude of the pressure reduction required to deplete or produce the undeveloped region. Additional oil could be obtained by development after a delay of fifteen years but a net loss of approximately 15 to 20 percent of the recoverable oil in the structure would still be left in the ground.

Summary

It is seen that regardless of the type of drive the idea of partial development of a structure, with full development being delayed for some fifteen years, results in a loss of recoverable petroleum and an increase in the cost of operation to the developer of this mineral resource. Unfortunately one cannot determine which type drive would be prevalent in a formation on this structure with present knowledge. The reservoirs which have been found in the potential oil bearing formations on this structure have indicated all three types of drive energies. Therefore, it would be inadvisable for an operator, both from a standpoint of mineral resource conservation and from a standpoint of economics, to delay development for a period of fifteen years on a part of a hydrocarbon accumulation.

THE BARBER FIELD

THE BARBER FIELD

I. Mr. Blackman has posed the following question: "The alternate location proposed by Pan American Petroleum Corporation is within a 100 ft. radius from existing Barber Field well #4-A, which is properly designated 4-J. Please state your opinion as to the probable future economic life of that well."

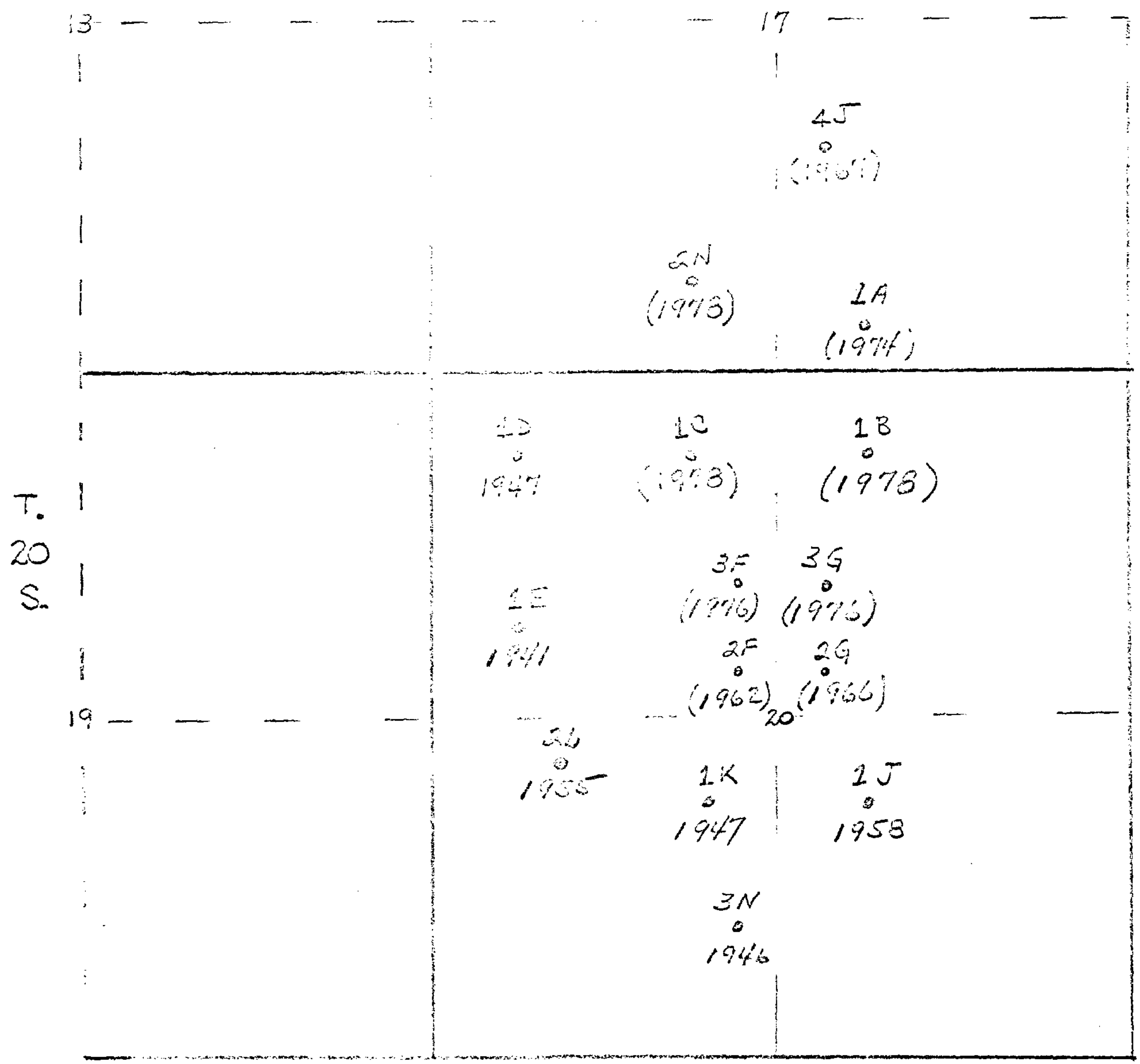
In answer to said question:

I have examined the production records of Barber Field well 4-J located in the NW1/4SE1/4 of Sec. 17, T. 20 S., R. 30 E., N.M.P.M. covering the period beginning June, 1942 and ending with calendar 1963. Based on that information, it is my opinion that well 4-J has a remaining economic life of from four to five years from the end of calendar 1963.

II. You have asked me to express my opinion on the future productive life of the remaining wells in the Barber Field. I have examined the production records of the

Barber Field, covering the period from 1941 through calendar 1963. As only the past production records were available, with no operating cost data, it was necessary that some limiting economic rate be assumed. All the answers which follow are based on a limiting economic rate of 45 barrels per month per well. Also, after studying well 4-J, it was assumed that only seven wells would be produced during the remainder of the field's economic productive life. Under these conditions, it is my opinion, that the Barber Field can be economically operated through calendar year 1974.

Because of the uncertainty of the limiting economic conditions for the field as a unit, I examined the production records of each well individually. Using the same limiting economic rate of production, an estimate was made of the year each well in Barber Field would become uneconomical to operate. The results of this evaluation are shown on Figure 1 entitled "Barber Field - Abandonment Schedule". It is noted from Figure 1 that three of the wells in the Barber Field could be economically productive into the calendar year 1978.



BARBER FIELD
EDDY COUNTY, NEW MEXICO
ABANDONMENT SCHEDULE
(1970) -- Projected year
1950 -- Actual year

GENERAL

GENERAL

You have asked that I "comment on the average values of hydrocarbons which have been produced in Southeast New Mexico from the Pennsylvanian and Devonian formations and make such comment as you deem appropriate concerning the value of the hydrocarbons which might be expected to be recovered under ideal conditions from a Pennsylvanian or Devonian reservoir confined within a structure such as that pictured on PCA Exhibit No. and your Map. No. 1."

In answering this request I will discuss first the producing formations in the area and then the probable content of these formations.

Producing Formations:

The major oil and/or gas producing formations of Pennsylvanian age or older are:

(1) Bend

(2) Pennsylvanian

(3) Devonian

(4) Siluro-Devonian

(5) Simpson

(6) Ellenberger

All oil fields in the eastern half of the state which had produced ten million barrels of oil by January 1, 1962 from formations of Pennsylvanian Age or older are shown in Table I. All gas fields in the eastern half of the state which had produced five billion cubic feet of gas by January 1, 1962 from formations of Pennsylvanian Age or older are shown in Table II. From a study of these two tables it becomes apparent that the Pennsylvanian and Devonian formations are the primary oil and gas producers of the group.

Since 1958 other fields have been developed which will soon join the ranks of those fields listed in the tables. The major fields which have been discovered since 1958 add very few new major producing formations to the list indicated prior to that time.

Discoveries as late as 1961 indicate that the Morrow formation may have possibilities of developing into a major gas producing formation and the Fusselman formation may have similar possibilities with respect to oil.

Also from studying the tables it is seen that forty acres per well is the predominant spacing in the oil fields and one-hundred and sixty acres per well is the predominant spacing in gas fields.

QUANTITY AND QUALITY OF POTENTIAL OIL PRODUCTION

A review of the Pennsylvanian, Devonian or related producing formations indicate that the potential oil is of highest quality (40° API or higher) and hence will command top market price.

The Pennsylvanian, Devonian and related age formations are generally limestones or dolomites. These formations range in productive thickness from 10 to 200 feet with porosity values from four to fourteen percent and initial water saturations from twenty to fifty percent. Using the lowest value of porosity and the highest value of water saturation results in an oil in place value of approximately 110 stock tank barrels per acre foot. The recoverable oil from this formation would be approximately 18 barrels per acre foot by solution gas drive and 45 barrels per acre foot by gas drive.

Using a porosity of fourteen percent and a water saturation value of twenty percent results in an oil in place value of approximately 620 stock tank barrels per acre foot. The recoverable oil from this formation would be approximately 125 barrels per acre foot by solution gas drive and 250 barrels per acre foot by water drive.

Combining the range of possible oil in place values with the wide range in thickness results in a very diverse potential economic value per acre. The minimum approximate value per acre would be for a ten foot thickness with four percent porosity, fifty percent water saturation and a solution gas recovery factor. This adverse combination of factors would result in a recovery of approximately 180 barrels of oil per acre with a value of approximately $540.00. The best conditions would be a formation 200 feet thick with a porosity of fourteen percent, water saturation of twenty percent and a water drive recovery factor. A reservoir under these very favorable conditions would recover approximately 50,000 barrels of oil per acre with a value of approximately $150,000.00.

From the values presented above it is seen that any well drilled to formations in the Pennsylvanian or older formation on eighty acre spacing has the potential of finding oil valued at between $43,200 and $12,000,000. In this particular area the formation which had a potential income of only $43,200 would not be considered a commercial well although it would probably be produced to recover as much of the drilling cost as possible.

An average oil field in the Pennsylvanian or older formations would probably have a porosity value of 6 percent, a thickness of 75 feet and a water saturation value of 35 percent such that the oil in place would be 216 barrels per acre foot. The potential recovery from a well developed in an eighty acre spacing pattern would be between 233,000 barrels (solution gas drive) and 518,000 barrels (water drive). The monetary value of such a well would be between $700,000 and $1,554,000.00.

The worst, average and best possible reservoirs obtainable in the area are summarized in Table III.

TABLE I. OIL FIELDS HAVING PRODUCED 10 MILLION BARRELS OR MORE FROM FORMATIONS OF PENNSYLVANIAN AGE OR OLDER

Field	Formation	Thick-ness	Approx. Spac-ing	Date of Disc.	Crude Gravity	Cummulative Production to 1/1/62 MM Barrels.
		LEA COUNTY				
Bagley Sil-Dev.	Siluro-Devonian	175	40	7-49	44	15
Brunson	Ellenberger	70	40	9-45	42	27
Caprock East Dev.	Devonian	30	40	8-51	43	14
Crossroads Dev.	Devonian	100	80	5-48	42	13
Denton	Devonian	200	40	10-49	45	61
Gladiola	Devonian	50	40	11-50	47	35
Hare	Simpson	50	40	7-47	40	14

TABLE II. GAS FIELDS HAVING PRODUCED FIVE TRILLION CUBIC FEET OR MORE

		EDDY COUNTY			
Anderson Penn	Bend	40	320	10-54	6.8
Atoka Penn	Penn	31	160	10-57	5.1
Empire Penn	Penn	30	320	9-53	9.1
Shugart Sil-Dev.	Siluro-Devonian	70	480	2-57	8.1
		LEA COUNTY			
Bagley L Penn	Penn	10	160	10-51	8.3
Bagley U Penn	Penn		320	11-55	13.1
Crosby Dev.	Devonian	95	160	1-55	41.7
Monument McKee	Simpson	40	160	11-48	5.6

TABLE III. RANGE OF CONDITIONS FOR POTENTIAL OIL RESERVOIR IN PENNSYLVANIAN OR OLDER FORMATION

	Worst		Best		Average	
PROPERTIES AND IN-PLACE VALUES						
Porosity, o/o	4		14		6	
Water Saturation, o/o	50		20		35	
Oil in Place Bbls/AF	110		620		216	
Thickness, Ft.	10		200		75	
Oil in Place Bbls/Acre	1,100		124,000		16,200	
RECOVERY						
	Solution Gas	Water	Solution Gas	Water	Solution Gas	Water
Recovery Bbls/Acre	180	450	25,000	50,000	2,916	6,480
Recovery Bbls/80 Acres	14,400	36,000	2,000,000	4,000,000	233,000	518,000
Recovery Dollars/80 Acres	$43,200	$108,000	$6,000,000	$12,000,000	$700,000	$1,554,000

CEMENTING

CEMENTING

Question: Are you generally familiar with the techniques and problems of cementing a deep oil or gas well?

Answer: Yes

Question: Would you enumerate some of the problems of cementing a well penetrating a thick salt section with several known loss circulation zones above and below the salt section?

Answer: In any region with loss circulation zones the major problem is to get adequate cement volumes in the desired locations. Two techniques may be used to cement casing in loss circulation zones. Both methods depend on putting the cement in the hole in stages.

Method I is to calculate the volume of cement required to fill the annulus from the bottom of the hole to the loss circulation zone and the volume of the cement that can be placed above the loss circulation zone without imposing too high a pressure on the loss circulation zone. This volume of cement is circulated into the annulus and permitted to obtain some set. A temperature survey is run to locate the top of the cement or a bond log is run to locate the top of the bond between cement and pipe. The casing is perforated at the top of cement or top of bond and with appropriate hole equipment in place, cement is circulated through the perforation to another preselected height in the annulus. This procedure may be repeated until cement fills the annulus to the desired height above the bottom of the hole.

Method II requires careful planning prior to the placement of the casing string in the hole.

In this method special gating devices are placed in the casing string which can be opened by plugs larger than a given diameter. The cement is again placed in the annulus in batches or stages with the first stage being displaced out the bottom of the casing, the second stage enters the annulus through the lowest stage tool and the third, fourth and other cement stages, if required, being pumped through sequentially higher stage tools. This method is desirable only when the location of the loss circulation zones can be accurately defined and it is known that each volume of cement staged into the hole will at least reach the height of the next stage tool.

Certain problems of cement placement are common to both of the methods previously mentioned. The major problems, other than loss circulation, are obtaining a uniform distribution of cement in theannulus and obtaining good pipe-cement and cement-formation bonds.

In order to obtain the most uniform distribution of cement in the annulus,centralizers are placed on the casing to try and provide an equal spacing between the hole and the pipe. Also to prevent channeling or "by-passing" of the cement, the velocity of the cement is controlled so as to obtain turbulent flow during the period of placement.

In order to improve the chances of obtaining a cement bond between the cement and the casing and wall of the hole the operator will usually prepare the pipe surface, use scratchers on the casing, use water ahead of the cement, control the velocity of the water and cement in the annulus, and use excess cement volume so that mud contaminated cement at the top and bottom of the column can be placed in regions not desired to be cemented. The major difficulty in obtaining a cement bond is reaching the surface at which a cement bond is desired. In washed out sections of the hole the velocity may decrease so that plug flow occurs and the mud is not displaced from the washed out volume. The engineer designing the cement job will use a calipher log and set the velocity so as to have turbulent flow in the largest indicated hole size. If the calipher log accurately defined the hole size, then the cement placement will probably displace the mud from the hole.

Question: Are special cements used in operations such as this?

Answer: Yes special chemicals can be mixed with the cement to provide desired properties, such as reduced weight, low water content, loss circulation material, setting retarders, etc. I am not familiar with the exact chemicals which might be used here, but such information could be obtained from Haliburton, Dowell or any other cementing firm by the engineer designing the cementing job. I am sure the properties of the cement would be considered in the design of any casing cement job.

Question: Does taking all the precautions you have enumerated guarantee a good cement job?

Answer: No guarantees are included. All of these steps are followed in a cementing job to create the most favorable conditions for obtaining a good cement job.

Question: If a cementing technique cannot be designed to guarantee a perfect job then how do you tell if you have any cement job at all?

Answer: There are four major ways of obtaining a qualitative check on the quality of the cement job obtained.

Two of the methods are primarily designed to locate the top of the cement column if it is not circulated to the surface. A radioactive material may be added to the lead volume of cement slurry and a gamma ray log run to detect the location of the radioactive cement after placement. The other method is to run a temperature measuring device in the hole during the time the cement is "setting". A change in the normal temperature gradient is observed at the top of the cement column. By knowing the volume of cement placed in the hole and a good estimate of the volume of the annulus it is possible to estimate if channeling of cement or loss of cement has occurred. Neither of these methods will indicate

(1) the strength of the set cement;

(2) the bonding of the cement to the casing and the wall of the hole;

(3) whether cement encircles the pipe or is just located on a portion of the pipe surface;

but does indicate

(1) the height to which cement has been placed;

(2) whether a measurable degree of channeling and loss circulation has occurred.

Another tool available for checking on the quality of a cement job is the Bond Log. This is a tool which generates sonic impulses and measures the magnitude of the energy of these impulses that is transmitted to a receiving device. If casing is surrounded only by fluid it will transmit a greater amount of energy than if it is resting against something solid. This transmission of energy is much the same as a bell whose sound can be muted by placing anything of a semi-solid nature against its surface. Thus the Bond Log indicates whether or not a section of the pipe is resting against something solid. The Bond Log will indicate the following:

(1) when the pipe is completely surrounded by fluid;

(2) when the pipe is resting against something solid, cement, cavings or side of the hole.

(3) additional drilling after the casing has been set creates impact loads because of the drill pipe and temperature increases because of the returning drilling fluid. Both of these factors could result in a failure of the casing cement.

Question: Is it possible that a casing cement job could be subjected a greater pressure than that used in testing the cement?

Answer: Yes, at shallow depths. Such a condition would normally only occur as a result of a "blow-out" during drilling when the "blow-out" preventors work. A formation with gas at 4500 psi at 10,000 feet could exert a pressure at 3800 feet in excess of 3800 psi and cause the formations to fracture. If casing were set in this example at any depth less than 3800 feet the formations between 3800 feet and the bottom of the casing would be subject to fracturing.

The Bond Log will not indicate the following:

(1) the strength of the bond against the pipe,

(2) whether the bond encircles the pipe,

(3) whether cement is bonded to the wall of the hole.

The fourth procedure of testing a casing cement job is to apply pressure and check for cement failure. The pressure is applied inside the casing and to the bottom of the cement column. This procedure only checks the casing for leaks and the very bottom of the cement column. This test does not necessarily locate weaknesses in the upper part of the cement column unless they are so severe that casing leaks result. Of course the maximum bottom hole test pressure that can be used is determined by the depth to the bottom of the casing. A pressure cannot be used which would cause fracturing of the formations.

Question: Could this fracturing cause a complete failure of the cement job?

Question: Is it possible that a casing cementing job could satisfy all of the tests and still fail at some future date?

Answer: Yes

Question: What might cause such a failure?

Answer: Essentially three factors might cause the cement job to fail at some later date. These three causes may be summarized as follows:

(1) the original cement job just barely met the test requirements but did not have sufficient strength or bonding to either the pipe or the wall of the hole;

(2) pressure testing of the cement job caused expansion of the pipe which could cause a loss of cement-pipe bond on release of pressure;

Question: Could this fracturing cause a complete failure of the cement job?

Answer: It would unless the formations above the fracturing were compentant enough to withstand the abnormal pressures and resulting deformation.

Question: Does perforation of the cemented casing endanger the cement-casing bond?

Answer: Perforating with jet charges does very little damage to the cement pipe bond, whereas, perforating with bullet guns would cause some fracturing of the cement sheath at the point of bullet entry. The effect of this fracturing normally does not extend any significant distance from the point of impact of the bullet. Hence, it probably would be concluded that perforation of the cemented casing does not hurt a good cement job. If the cement job is not a good one then any additional surface exposure could result in a complete failure of the cement-casing bond.

Question: Is there any known non-destructive method of determining the inplace strength of cement job in an oil or gas well?

Answer: No

Question: If a high pressure gas well, such as Federal Dooley #1 which has a bottom hole pressure of 5000 psi, were leaking through the cement at the production perforations into the salt section at a rate of approximately 50,000 cubic feet per day, would it be possible to detect such a loss?

Answer: I must answer your question with a conditional yes.

Question: How would you detect such a leak?

Answer: As you have stipulated the leak to be located at the producing perforations, the leak could not be detected using temperature and pressure measuring devices within the well during test periods. The only means of detecting such a small loss would be the use of a volumetric gas balance applied over an extended period of production. By observing the shut in pressure after fixed intervals of production, it would be possible to determine that fluid was leaving the reservoir which was not accounted for by the production measured at the surface. The length of time required to detect this loss of fluid would depend on the rate of gas production and the size of the leak. Figure 1 shows the ideal performance and the performance that would be observed if the loss were uniformly one percent and ten percent of the total reservoir production. It is noted from Figure 1 that the smaller the leak the greater the value of cumulative production at which the leak can be detected.

If the gas reservoir was producing under the influence of a partial water drive, it would be difficult if not impossible to detect an underground loss of gas equivalent to one percent of the total gas removed from the reservoir.

Because of the possibility of water influx and the probability that a loss of 50,000 cubic feet per day would represent less than one percent of the production, one cannot answer your question with an unconditional yes.

Question: If a non-commercial gas or oil well is plugged and abandoned, is there any way in which a leak may be detected around the cement outside the productive casing string?

Answer: No