CASE 7299: KOCH INDUSTRIES, INC. FOR [illegible] OF A TIGEE FORMATION, SAN JUAN COUNTY, NEW MEXICO.

CASE NO.

7209

APPLICATION,

TRANSCRIPTS,

SMALL EXHIBITS,

ETC.

KOCH HYDROCARBON COMPANY

October 1, 1981

Mr. Daniel S. Nutter
Chief Engineer and Trial Examiner
Case No. 7209
State of New Mexico
Energy and Minerals Department
P. O. Box 2088
Santa Fe, New Mexico 87501

Re: Koch Industries, Inc.
Application for Designation
of Tight Formation
Rattlesnake Canyon Area, San
Juan County, New Mexico,
Case No. 7209

Dear Mr. Nutter:

Reference is made to your September 1, 1981 letter to the attention of our attorney, Mr. William F. Carr, requesting additional data in the subject case.

Enclosed are four copies each of revised Exhibits 6 and 13 along with brief descriptive narratives. Please substitute the enclosed exhibits and narratives for the original Exhibits 6 and 13 submitted prior to our March 25, 1981 hearing. Exhibit 6 has been revised to show estimated recoverable Mesa Verde reserves for all the wells in the proposed Tight Formation Area. Exhibit 13 has been revised to show the economics of producing an average well in the area to depletion at both the NGPA Section 103 price and the Tight Gas incentive price.

We hope with this additional information you will be able to make a favorable recommendation to the FERC that the Rattlesnake Canyon Area Mesa Verde Formation qualifies for tight formation incentive pricing.

Very truly yours,

KOCH HYDROCARBON COMPANY

Charles M. Pavlica
Supervisor, Gas Contracts

CMP:ep

Enclosures

RECEIVED
OCT 05 1981
OIL CONSERVATION DIVISION

cc: United States Geological Society
P. O. Box 26124
Albuquerque, N.M. 87125

Mr. William F. Carr
Campbell, Byrd & Black, P.A.
P. O. Box 2208
Santa Fe, New Mexico 87501

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

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POST OFFICE BOX 2088
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SANTA FE, NEW MEXICO 87501
(505) 827-2434

September 1, 1981

Campbell, Byrd & Black, P.A.
P. O. Box 2208
Santa Fe, New Mexico 87501

Attention: William F. Carr, Esq.

Gentlemen:

Regarding Case No. 7209, the application of Koch Industries, Inc., for designation of a tight formation, which was heard by me on March 25, 1981, we feel that certain additional information is necessary in order to make a proper recommendation to the Federal Energy Regulatory Commission as to which lands covered by the application should be considered for recommendation and the criteria which should be used in analyzing the lands.

I have discussed this matter with Mr. David B. Friend, the consulting reservoir engineer who prepared and presented Koch's case, and have advised him that we will need the following:

1. Estimated recoverable Mesaverde reserves for the entire area of interest, (section by section), or at least for the lands in the lowermost two tiers of sections in the area, i.e., Sections 30 and 31, Township 32 North, Range 8 West, and Sections 25 through 27 and 34 through 36 of Township 32 North, Range 9 West. This could be submitted by a revised Exhibit No. 6.

2. A calculation of the economics involved in determining the necessity for the incentive price pursuant to the provisions of 18 CFR §271.703(c)(2)(D). These data should show the economics of producing an average well in the area to depletion, and show the rate of return which could be expected under normal Section 103 price for the gas as compared to the rate of return which could be expected under the incentive price. Both of these rates of return should be compared to a reasonable

rate of return which Koch finds is necessary to justify additional drilling in the area. These data could be submitted in the form of a revised Exhibit No. 13.

Upon receipt of the above information, we will be happy to continue our analysis of the evidence in Case No. 7209, and would hope to be able to make a recommendation to the FERC soon.

Very truly yours,

DANIEL S. NUTTER
Chief Engineer and
Trial Examiner, Case No. 7209

DSN/dr

Depth to top of Cliff House.

Sk 31 ① 5705'
② 5670
③ 5435'
④ 5420
⑤ 5400
A'⑥ 5445'
Sk 48 D 5305'
1 ⑥ 5410
~~⑥ 5435'~~ repeat of A-A' at ③
B'⑥ 5360

File 7209
Cave
Koontz

9/49170/5463

ave top of cliffhouse
5463'

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
25 March 1981

IN THE MATTER OF:

Application of Koch Industries, Inc. for designation of a tight formation, San Juan County, New Mexico.

CASE 7209

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:

Ernest L. Padilla, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant:

William F. Carr, Esq.
CAMPBELL, BYRD, & BLACK P.A.
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MR. NUTTER: We'll call Case Number 7209.

MR. PADILLA: Application of Koch Industries, Inc., for designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, P. A., in Santa Fe, New Mexico, appearing on behalf of Koch Industries, Inc.

I have two witnesses who need to be sworn.

(Witnesses sworn.)

MR. CARR: I'll call Richard Luce.

RICHARD LUCE

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your full name and place of residence?

A. Richard M. Luce, 1 Park Central, Suite

530, Denver, Colorado.

Q Mr. Luce, by whom are you employed and in what capacity?

A Koch Exploration Company. I'm an exploration geologist.

Q Will you briefly summarize your educational background and your work experience?

A Yes. I graduated with a Bachelor of Science degree -- yes, a Bachelor of Science degree in 1976 in geological engineering from Michigan Technilogical University.

At that time I was employed by Tenneco Oil Company for a period of about two and a half years, during which time I was primarily in the capacity of a development geologist, working in the San Juan Basin area.

In January, 1979, I went to work for Koch Exploration Company as an exploration geologist and I've been working for them shortly over two years, working various areas in the Rocky Mountain Region, including the San Juan Basin.

Q Are you familiar with the application which has been filed in this case?

A Yes, I am.

Q Are you familiar with the acreage which

is the subject of this application?

A. Yes, I am.

MR. CARR: Are the witness' qualifications acceptable?

MR. NUTTER: Yes, they are.

Q. Will you briefly state what Koch seeks with this application?

A. Koch is seeking a designation of the Mesaverde formation as a tight formation for an area in northern San Juan County, New Mexico, and includes the following lands: Township 32 North Range 8 West, Section 7, 18, 19, 30, and 31; and Township 32 North, Range 9 West, Sections 10 to 15, inclusive; 22 to 27, inclusive; and 34 to 35, inclusive.

Q. Mr. Luce, have you prepared certain exhibits for introduction in this case?

A. Yes, I have.

Q. Have each of these exhibits previously been submitted to the Oil Conservation Division and to the United States Geological Survey, with a statement of the meaning and purpose of each, as required by Oil Conservation Division rules?

A. Yes.

Q. Will you please refer to what has been

marked for identification as Koch Exhibit One identify this, and explain to the Examiner what it shows?

A. Okay. Exhibit One is a structure map on the top of the green marker, which is approximately 350 feet above the top of the Cliffhouse member of the Mesaverde formation. It's persistent across the area.

The map shows a regional dip generally to the northeast at less than one-half degree. It also shows the land ownership for the -- the proposed tight formation area. This land includes 480 acres of fee acreage, 10,071 acres of Federal acreage, for a total of 10,551 acres in this proposed area.

Q. What are Koch's acreage holdings in this area?

A. Koch holds approximately 2336 acres in this area.

Q. And there are no State lands in the area for which you are seeking a designation.

A. That's correct.

Q. Would you now refer to Koch's Exhibit Number Two and review this for Mr. Nutter?

A. Okay. Exhibit Number Two is hanging up there on the wall, Mr. Nutter. It's a type log in the Mesaverde formation. I believe it's designated as a type log

on the Exhibit Number One in the Section 25 of 32 North, 9 West.

This exhibit shows the interval from the green marker datum contoured on Exhibit One and also includes the Cliffhouse, Menefee, and Point Lookout members of the Mesaverde formation.

The vertical limits of the Blanco-Mesaverde Pool have been defined by the New Mexico Oil Conservation Division in this area as extending from the Huerfanito Bentonite in the Lewis Shale to a point 500 feet below the top of the Point Lookout member.

The H uerfanito Bentonite on this type log exists about 816 feet above the green marker.

The CliffHouse and Point Lookout members are considered the main producing zones of this field but less continuous sands of the Menefee also contribute to the overall production of the Mesaverde in this area.

In the proposed tight gas sand area the Cliff House averages only about 50 feet thick and the porosity ranges from less than four percent to fifteen percent.

The Menefee in this area ranges from 230 to 290 feet thick and the porosity varies from less than three percent to about seventeen percent.

The lower member of the Point Lookout

sands are about 150 to 200 feet thick in this area and there are also significant stringers of sand that may be seen as low as 300 feet or so below the top of that Point Lookout member.

The porosity in this Point Lookout type -- or the porosity in the Point Lookout in the type log ranges from about three percent to fourteen percent and is considered typical of the porosity in this area.

The average porosity for these sands of all three members is about eight percent.

Q. Mr. Luce, will you now refer to Koch Exhibits Three and Four and review these for Mr. Nutter?

A. Exhibits Three and Four are west/east and southwest/northeast stratigraphic cross sections through this area. The datum for these cross sections is the green marker. They show the continuity of the Cliff House and the Point Lookout sands across this area, and what also can be seen from these two cross sections is the irregularity of the sands in the Menefee.

The Point Lookout consists of near shore or shoreline sands deposited during an overall regression of the Mancos Sea. The sand buildups in this area represent periods of still stand during that regression. The sands have been described as light gray, very fine to fine grain,

well cemented, argillaceous matrix, with poor visible porosity.

The Menefee represents a period of non-marine deposition during Mesaverde time. Environments of deposition include coal-forming swamps and coastal plain deposits. Numerous coals, silts, and shales, and channel sands can be observed in a typical Menefee section. Reservoir quality often is similar to that of the Cliff House and Point Lookout sands but the continuity and predictability of these sands is very poor.

Binocular description of the sands is not appreciably different than that description of the Point Lookout sands.

Finally, the Cliff House consists of a widespread shoreline sand deposited during transgression of the Lewis Sea. These sand buildups represent stillstands during that transgression.

Again, binocular description of these sands is very similar to that of Point Lookout and the Menefee members.

The Cliff House in the proposed area is nearly to the point where it's pinched out completely and there's only about -- there's only fifty feet of total interval and about ten feet of that is potentially productive. The gross interval of the Menefee contains an average of only two

to three benches of productive, potentially productive sands, whereas to the south the wells have Menefee sections of greater than 1000 feet with several potentially productive benches.

The Point Lookout in this area is also near its seaward edge of -- of its seaward productive limit. The overall -- overall the area is near the productive limit of the various members of the Mesaverde with relatively few objective zones in this area. We view the risk of drilling an uneconomic well is considerably greater than even a few miles to the south.

Q. Mr. Luce, does the Mesaverde formation underlie all the acreage for which you are requesting a tight formation designation?

A. Yes, it does.

Q. And in your opinion is the formation productive throughout the area?

A. Yes, it is.

Q. What is the average depth from the surface to the top of the Mesaverde formation?

A. It's approximately 4200 feet.

Q. Were Exhibits One through Four either prepared by you or under your direction and supervision?

A. Yes, they were.

MR. CARR: At this time, Mr. Nutter, we

would offer into evidence Koch Exhibits One through Four.

MR. NUTTER: Exhibits One through Four will be admitted in evidence.

MR. CARR: I have nothing further of this witness on direct.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Luce, now your Exhibit Number One indicates that there's a total of 10,551 acres in the area under consideration. That is the area that's outlined by the little hachured line, that --

A. Yes, sir, that's correct.

Q. Okay. Now, in that area there are 480 fee acres. Would you identify the fee acres, please?

A. Yes, those are outlined by the dash-dot type of pattern. There -- there's 160 acres in Section 14 of 32 North, 9 West; a 40-acre tract in the southwest southwest of Section 22, 32 North, 9 West; and about 280 acres in Section 27 of 32 North, 9 West.

Q. Now there have been wells drilled in the total 10,551 acres, have there not --

A. Yes, sir, that's correct.

Q. -- that penetrated the Mesaverde.

A That's correct.

Q How many Mesaverde wells are in here?

A Fourteen wells.

Q And this Exhibit Number Two, which is the log of the Gardner No. 5, is this a typical log for all of the wells that have been drilled in the area?

A Yes, sir, we believe that it's fairly representative of the wells in this area.

Q Now you talked about the first -- the porosity of the area but you didn't get into permeability, is that right?

A The permeability will be discussed by our reservoir engineer.

Q I see.

MR. NUTTER: Are there any further questions of Mr. Luce? He may be excused.

MR. CARR: I'll call David Friend.

DAVID D. FRIEND

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your full name and place of residence?

A. David D. Friend, 2327 Ventoso, Wichita, Kansas, 67204.

Q. Mr. Friend, by whom are you employed and in what capacity?

A. I am self-employed as a consulting engineer. Koch Industries has employed me to prepare data for this hearing.

Q. Have you previously testified before this Commission or one of its examiners?

A. No, I have not.

Q. Will you summarize for Mr. Nutter your educational background and your work experience?

A. I received both Bachelor of Science and Master of Science degrees from the Missouri School of Mines. I received the Master of Science degree in 1961.

I joined Texaco in south Lousiana and worked as a field engineer and reservoir engineer until January of 1968.

In January of 1968 I joined Hunt Oil Company as Project Engineer at the Fairway Missable Gas and Water Injection Project, East Texas.

In August of 1969 I joined CORE Labor-

atories engineering and consulting group and worked with them as a consulting engineer on projects both in the United States and foreign.

In April of 1974 I joined Tesoro Petroleum Corporation and was moved into the position of Chief Reservoir Engineer, responsible for domestic and part of their foreign work.

In August of 1978 I joined Koch Exploration. One of my duties with Koch Exploration was development drilling of San Juan Basin.

In August of 1980 I resigned from Koch and have worked as an independent consulting engineer.

MR. NUTTER: How do you spell your last name, please?

A. F-R-I-E-N-D.

MR. NUTTER: Thank you.

Q. Are you familiar with the application which was filed for Koch in this case?

A. Yes, I am.

Q. Are you familiar with the subject area?

A. Yes, I am.

Q. Have you prepared certain exhibits for introduction in this case?

A. Yes, I have.

Q Have each of those exhibits previously been submitted to the USGS and the OCD, as required by Division rules?

A They have.

Q Will you please refer to what has been marked for identification as Koch Exhibit Number Five, and review this for Mr. Nutter?

A Before we get into Exhibit Number Five, I would like to comment, we have reviewed State and Federal regulations concerning protection of fresh water.

Exhibit Number Five presents a schematic of the typical well completion for Koch-operated wells. The completion procedure is in line with State and Federal regulations which require that casing programs be designed to seal off potential water-bearing formations, thus separating them from oil and gas-bearing formations.

The illustration shows that 14-3/4 inch hole is drilled to approximately 200 feet: 10-3/4 inch casing is cemented in place with the cement being circulated to surface.

An 8-3/4 inch hole is drilled to approximately 3500 feet and 7-inch casing set with cement again being circulated to the surface; a 6-1/4th inch hole is gas drilled to total depth and 4-1/2 inch casing set and cemented

with enough cement to extend up into the 7-inch casing.

A temperature survey is run to determine the top of the cement in the production string.

The base of the Ojo Alamo is shown on the exhibit as being at 2185 feet. Fresh water aquifers extend from the surface to the base of the Ojo Alamo; a distance of approximately 4000 feet separates the normal perforated Mesaverde interval and the base of the fresh water aquifer. The chance of a frac flood or gas being communicated with fresh water over this long interval is, well, it just should not happen. It should not be communicated.

In the event that there is communication behind pipe, Koch would squeeze the channel, perform whatever remedial work is required to isolate the intervals.

The upper 3500 feet of the well is drilled with native mud which will not contaminate fresh water zones. During well completion operations the three zones are individually broke down with approximately 500 gallons of 7-1/2 percent acid prior to fracing. It is my opinion that this acid will not contaminate an extensive aquifer.

The frac fluid used consists of fresh water with approximately 2 percent KCL added, and again, this fluid would not contaminate an extensive aquifer.

Q If you experience a leak during the life of this well, would you anticipate that the waters in the area would be contaminated with fluids from the well or would it work so that the fluids migrated into the wellbore?

A The water would migrate into the wellbore and down into the gas zone.

Q Now, do these fresh water zones exist throughout the area?

A I believe that they do.

Q I believe you stated that you'd reviewed applicable State and Federal regulations.

A Yes, I have.

Q In your opinion will compliance with these regulations assure that the development of the portion of the Mesaverde formation which is the subject of this hearing not adversely affect or impair any fresh water aquifers during any fracturing or waste disposal operations which you now use or could anticipate using?

A No, it will not, and I believe that this is the best effort I have seen in any area, where people have tried to protect the fresh water sands.

Q Is it your testimony that the proposed development of the subject area will not affect either domestic or agricultural water supplies?

A. Yes, sir, it is.

Q. All right, Mr. Friend will you now refer to what has been marked as Koch Exhibit Number Six and review this for Mr. Nutter?

Exhibit Six is located in the folder behind the summary. In the lefthand side of the folder is first a summary, then a list of these exhibits with a statement of the meaning of each, and then behind that should be the remaining exhibits.

MR. NUTTER: What does Six look like?

A. It's a table.

MR. CARR: That's Exhibit Number Seven, now, DAvid.

A. Okay. Number Six is our tight sands production map. I'm sorry.

MR. CARR: The exhibits in that folder start with Exhibit Seven. We have a plat which is Exhibit Six.

A. Exhibit Nurber Six is a production map of the tight formation area. and many of the surrounding wells; anticipated is all the production expected from Koch operated wells as determined by Ryder Scott Petroleum Engineers. a consulting company that Koch uses to determine their reserves, as shown from the Koch wells.

The map shows at the south and the west the cumulative gas production from the wells has been more than in a tight formation area.

Q. Will you now refer to your Exhibit Number Seven and review this for Mr. Nutter?

A. Exhibit Number Seven lists the wells in the tight sand area which are operated by companies other than Koch. These wells were drilled --

MR. NUTTER: Just a minute, please. Thank you.

A. Exhibit Number Seven shows wells in the tight sand area which are operated by companies other than Koch. These wells were drilled prior to 1960 and all wells were stimulated. No pre-stimulation rates were reported and the post stimulation rates range from an IP of 145 Mcf per day to 3483 Mcf per day absolute open flow.

Q. Mr. Friend, will you now review Exhibit Number Eight?

A. Exhibit Number Eight lists the Koch operated wells in the tight formation area.

The first well was drilled in 1954. No additional wells were drilled until 1976. The results of the wells drilled in 1976 were disappointing and development was suspended until 1980, when two additional step-out wells

and one infill well was drilled.

Koch has again stopped drilling due to poor economics. As many as seven or eight additional wells can be drilled on the Koch acreage alone if the economics are more favorable.

The only Koch operated wells producing measureable gas prior to stimulation was Gardner No. 1. The details of this test are not known. It is doubtful that this represents a stabilized flow rate.

All the wells were drilled with gas, which provided a continuous test. Gardner Well No. 4 was the only well with a slight show of gas while drilling. Gardner Well No. 5 produced at a rate too small to measure prior to stimulation.

Various types of well completions have been tried by Koch in an attempt to increase gas production. Each interval shown on the exhibit has been frac treated alone.

The number of intervals has been varied from two to three. Total frac treatments range in size from 80,000 pounds to a massive 293,000 pounds. The post-stimulation flow rates shown on the exhibit should not be considered as representative of a well's long term ability to produce. Producing rates show a rapid decline following initial potential.

The most recent wells drilled are Gardner No. 4-A and No. 5. The respective drilling and completion costs were $489,000 and $407,000 for these wells.

MR. NUTTER. Give me those figures again please.

A. Okay. For Well 4 A it was $489,000. For Well No. 5 it was $407,000.

MR. NUTTER $470,000?

A. $407,000.

MR. NUTTER: $407,000. Mr. Friend, do you have any idea what percentage or what amount of that total cost was for stimulation?

A. For Well 4-A Koch paid $67,000 to the treating company.

For Well No. 5 Koch paid $74,000.

MR. NUTTER: Thank you.

A. And that does not include rig time or other related expenses.

Q. Mr. Friend, have you been able to establish pre-stimulation permeability?

A. In an area with a very low permeability such as this has it is very difficult to run the standard build up test prior to stimulation. It is very difficult to determine permeability by the standard means.

We have used two methods here in an attempt to approximate permeability and to get a reasonable feel for -- for the value.

Q. Have any of the wells been cored?

A. None of the wells have been cored.

Q. Have you attempted to calculate the pre-stimulation flow rates?

A. One pre-stimulation flow rate was available and that was from Gardner Well No. 1 and as mentioned before, the test data is not well documented, so certain assumptions are necessary to perform calculations to determine permeability based on the reported rate of ~~407~~ 47 Mcf per day.

First, it was assumed that this was a stable rate, and it was also assumed that the flowing wellhead pressure was at or near atmospheric pressure.

A porosity log was not run on this well; therefor, the net pay of 149 feet, based on Gardner Well No. 5, was assigned to part of these calculations.

Exhibit Number Nine presents the calculations used to determine the permeability. The results show a permeability of .0208 millidarcies, and this is probably high. As I mentioned, the flow rate might not have been stable.

Q And this rate was calculated using

Darcy's law, is that correct?

A. Yes, it was based on Darcy's law.

Q. What other efforts did you undertake to calculate permeability?

A. We used actual test data from Gardner Well No. 3 and a computer program designed to calculate permeability based on performance.

The basis for the analysis for this paper is by Gringarten, Ramey, and Raghavan, which was published in Volume 257 of the AIME Transactions. Solution of the problem was made possible by the use of the Garrett Computing System, their program "gas well performance simulation." The Garrett System is obtaining nationwide use in the industry.

Q. Are copies of that report included with the material that has been supplied to the Commission?

A. Copies of the report was -- was included.

Exhibit Number Ten presents the data input to calculate the porosity -- the permeability from Gardner No. 1 -- No. 3, I'm sorry. The porosity used was 11.7 percent with a net pay of approximately 250 feet; liquid saturation 55 percent; reservoir pressure of 150 degrees Fahrenheit; and a drainage area of 160 acres was used.

The test data and the date of the test is shown on the exhibit and the flow rates also indicate the

rapid decline of the well's potential after it has been put on.

The calculated permeability based on different fracture lengths to match the history, are shown as the results in Exhibit Number Ten. It can be seen that the last slope here where the rate was 115 Mcf per day, that a reasonable match is obtained with a permeability of .00122 to .0125, 126, millidarcies.

The basic assumptions in the computer program include a single, uniform interval in a homogeneous reservoir, and the Mesaverde does not meet this requirement, and since more -- since each zone is fraced separately, we did not have a single uniform fracture exist in the well. We would contend that the well is producing as though it were a homogeneous reservoir with a permeability of about .0012 or .0013 millidarcies permeability.

Q. Mr. Friend, in your opinion, based on the data that is available to you on this formation is the permeability throughout this area less than one-tenth millidarcy per foot?

A. Yes, it is.

Q. Will you please refer now to what has been marked for identification as Koch Exhibit Number Eleven?

A. Exhibit Number Eleven shows the completion

date, cumulative production, and current status of wells completed in the Mesaverde formation in the proposed tight formation area. The remaining reserves as determined by Ryder Scott Engineers are included for the Koch operated wells. Comparison of the completion data and the current status shows the -- again shows the rapid early production decline experienced in Gardner Wells 2, 3, 3-A, and 4.

Q. Mr. Friend, will you now review Exhibit Number Twelve for Mr. Nutter?

A. Exhibit Number Twelve is a cost estimate to drill and complete the wells to the Mesaverde formation tight sand area. You'll notice the total cost of the estimate is $400,700, which is actually less than the last two wells cost, and this is assuming a completely trouble-free well.

Q. Will you now refer to Exhibit Number Thirteen?

A. Exhibit Number Thirteen presents an economic analysis for a well drilled in the tight gas formation area. Production data used for the projection was taken from the first twenty-five years of history from the Gardner Well No. 1. The assumptions used in the economic analysis are shown on the first page of the exhibit.

The exhibit also presents the results

of analysis that would show that a discounted flow rate of return is 7 percent with a payout period of 9.4 years before income tax. These values are reduced to 6 percent rate of return with a 10.4 year payout after income tax.

Pages two and three of the -- are the computer printout for this case.

Section 107 tight gas formation prices were also used to determine payout and rate of return. In this case the after tax rate of return will be twenty percent and the payout will be four years, neither of which is excessive but they should be acceptable.

MR. NUTTER: Is that given on one of the exhibits?

A. No, it is not shown on an exhibit.

Q. Mr. Friend, in looking at this Exhibit Thirteen, the figures that you've used appear to assume that no drilling difficulties or risks are included or incurred.

A. That is correct. This is the minimum drilling and completion costs.

Q. How would this affect the actual parameters for these figures?

A. They're just cost of drilling, and as I mentioned before, one of the last wells drilled did cost considerably more than the $400,000. The rate of return is

even more; payout is extended.

Q Is it fair to assume that the actual parameters would be less attractive than those you have shown?

A Yes.

Q Is the 107 price necessary to provide a reasonable incentive for production of natural gas from the formation, due to the extraordinary risks and costs associated with such production?

A Yes, Section 107 tight gas formation prices will provide a more favorable economics and will result in additional development in the area. It is very doubtful that Koch would drill any additional wells in the area in the near future without an increase in gas price, and under existing economic conditions they have stated they will not drill additional wells.

Q Has this area been designated as an area that can be developed with an infill drilling program?

A Yes, it has.

Q Would the statement which you have made concerning Koch's unwillingness to drill additional wells in this area due to economic considerations also apply to the infill wells?

A Yes, it would.

Q Will you now review your Exhibit Number

Fourteen for Mr. Nutter?

A Exhibit Number Fourteen presents a summary of pertinent reservoir data for the Mesaverde formation in the tight gas area.

The average porosity is about 11.3 percent, based on a porosity cutoff of 8 percent. This is not the same porosity value which was mentioned earlier; however, the lower porosity given by Mr. Luce uses a much lower porosity cutoff and we feel that the 8 percent, while it might not include all gas which is produced, it will include most of the gas that is produced.

A definite permeability was not established; however, the permeability which is shown is less than .02 millidarcies and certainly it's less than .1 millidarcies.

The original reservoir pressure is 1177 pounds. The reservoir temperature of 150 degrees. The average net pay from Koch's wells is 156 feet and there is no oil production from any of the wells in the tight area -- tight formation area.

Q Mr. Friend, could you summarize the conclusions you can -- you have reached as a result of this study?

A The Mesaverde formation in the proposed area meets the guidelines necessary to qualify the area for

tight formation designation.

These are, the in situ permeability is less than .1 millidarcy; the stabilized gas production rate is less than 163 Mcf maximum permitted for wells completed below 5000 feet. No well will produce more than 5 barrels of oil per day. The fresh water sands in the area will be adequately protected during drilling and completion and production operations.

In addition, wells completed in the area will show favorable economics based on an incentive 107 price; based on the existing gas price the economics are unfavorable.

Q. Mr. Friend, concerning your statement relating to the production of less than 5 barrels of crude oil per day, do these wells produce any fluid at all?

A. They do not produce any oil at all.

Q. Do they produce any condensate?

A. No, they do not.

Q. Were Exhibits Five through Fourteen prepared by you or under your direction and supervision?

A. Yes, they were.

Q. In your opinion will granting this application be in the best interest of conservation and prevention of waste, and the protection of correlative rights?

A. Yes, it will.

MR. CARR: At this time, Mr. Nutter, we would offer into evidence Koch Exhibits Five through Fourteen.

MR. NUTTER: Exhibits Five through Fourteen will be admitted in evidence.

MR. CARR: I have nothing further of Mr. Friend on direct.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Friend, first of all, on your Exhibit Number Six you've got the area as outlined, or the area that's under consideration outlined there, and to the east I see an area that says San Juan 32-8 units; to the west I see San Juan 32-9 units.

A. Yes, sir.

Q. Are these lands that are under consideration in either of those units or are they lands that lie between the two units?

A. The Koch acreage could be included in there, should be included in 32-9 unit area.

Q. Which is the Koch acreage?

A. That's the acreage which is shown in the hachured part of the map.

Q Okay, that's in Section 25, 26, part of 27, 35, and 31 in the next township over.

A Yes, yes, it is.

Q Okay, and El Paso and Northwest operate these other wells, or own the other lands, is that it?

A Yes. There are other operators in the general area but most of the wells are operated by El Paso and Northwest.

Q Now what was the basis for determining that this particular area that you've outlined here would be the area for study of the tight sand?

A The northern area that was picked as the Colorado border.

Q Okay.

A Section 36 was not included because it is now fully developed.

The other acreage, other than Koch's, was included to square up the area and to give an area which other operators could easily identify to in the event that they want to submit their own tight formation hearing.

Q Naturally what you were interested in is designation of the Koch acreage.

A That is right.

Q And does Koch own Section 36?

A. No, they do not. It's part of the San Juan 32-9 unit.

Q. Now it looks like Section 31 already has one -- it's fully developed with one infill well already drilled, is that right?

A. There is one more well.

Q. Uh-huh.

A. Yeah, the second infill well.

Q. Now these cumulative productions that are given as zero, that means the well has not gone on the line yet?

A. It was not on line October 31st of 1980.

Q. And what are the estimated ultimate productions based on for these wells?

A. Those are -- for the Koch wells it's based on the Ryder Scott estimate. Ryder Scott is a consulting company in Houston.

Q. Okay, and I believe the actual figures were included on some exhibit there, weren't they?

A. Yes, they are.

Q. Now, on these economics you have taken a well on your Exhibit Number Thirteen, and is this a well or this a hypothetical well?

A. That is actual production data from

Gardner Well No. 1.

Q. Which was completed back in 1954.

A. Yes, that's the first twenty-five years of production from that well.

Q. And the data from that well is punched out on the computer on page two of Exhibit Three, isn't it?

A. Yes, Exhibit Thirteen.

Q. So you show that the well is producing gas at $2.39 a barrel --

A. Right.

Q. -- in Mcf. That well hasn't produced $2.39 gas since 1954 by any means, has it?

A. No, this is based on the assumption that a well would now produce at $2.38.

Q. Right. So you're taking present day economics and applying it to an old well's production history.

A. Yes, we are.

Q. Now is this operating cost of $4800 a month typical of Koch's operating costs up there?

A. I'm afraid it will be. Some of the wells are producing some water. They're having to run small tubing in the wells. They do have to occasionally swab the wells in. This is not an easy area to operate in.

Q. I see. So these aren't gas wells you

can just go turn on and forget.

A. No, they're not.

Q. And you calculate, based on the history from Gardner No. 1, and that's the only old well that Koch operates in the area --

A. Yes.

Q. -- you calculate that based on today's economics, without the tight sand incentive price, in other words a gas price of $2.39 an Mcf, that before income tax it will take 9.4 years to get a payout.

A. Yes, sir.

Q. And after income tax, 10.4 years.

A. Yes.

Q. And this gives you a discounted cash flow rate of return of 6 percent.

A. Yes, after income tax.

Q. Now you said no cores have been taken in the area?

A. Not in the area that we are considering here.

Q. Now you had an exhibit -- I can't find it right now -- where you took this pre-stimulation flow rate of 47 Mcf from that one well and used it for calculating permeability. What exhibit was that, Mr. Friend?

A. That was Number Nine, I believe.

Q. Now you stated -- this well did actually flow 47 Mcf per day against an atmospheric pressure, assumed atmospheric pressure, but when you first went over this data you mentioned you didn't think it was stabilized flow rate. Do you think a stabilized flow rate would have been lower than that?

A. Much lower. I'm not at all certain these wells will flow at all at a stable rate.

Q. So on your Exhibit Number Nine you gave the well the benefit of the doubt.

A. Yes.

Q. And said, now it made 47 Mcf on a puff here when it was first completed and you're going to assume it will continue puffing at that rate.

A. That's right.

Q. And you calculated a permeability then of .02ths of a millidarcy.

A. Yes.

Q. Now what about Section 3 to the south of your area here, Mr. Friend? I don't see any wells in there at all.

A. No, there are none.

Q. And there is a well in Section 2 in the

northwest quarter which has no history. What's -- what's the characteristic of that well?

A. It is a new well.

Q. I see.

A. We did check with Aztec to make certain that no wells had been drilled in 3 and they confirmed that there are none.

Q. You stated that the better part of the Mesaverde is to the south and to the west here.

A. Yes.

MR. NUTTER: Are there any further questions of Mr. Friend? Yes, sir.

MR. HIGGINS: My name is Robert Higgins. I'm with the U. S. Geological Survey in Albuquerque, and we reviewed this and basically have no problems. I just want to bring up the issue of some of the boundary criteria in this case.

It appears that the boundary here is based on lease lines, the section boundary, is that correct?

A. That is correct.

MR. HIGGINS: What we're interested in is if there's any physical criteria that we could demarcate these areas of tight -- where the tight formation is between the good producing trends and the tight gas is, so that we

can -- it's tied into either production of wells or geologic, either stratigraphic or the geometry of the thing, or something of that nature so you could get large amounts of acreage that is based on something that's physical rather than just seeing a lot of these cases, tight gas cases, that just crop up depending on who is the owner, if there would be some way to get together and have large acreages designated that all have similar characteristics, whether physically measured or mapped or something else.

So, I know that's difficult; in some cases impossible task, but as a regulatory agency it makes our task simplier than looking at ten cases and seeing tight gas intervals.

You could identify trends for us. This is a good producing trend and the poor producing trend begins here, so that is the tight gas area. It's just an issue at the Survey that we thought we should bring forth because a lot of these cases are being brought up and they seem to be all tied into just who owns what acreage rather than something that is geologic or engineering trends.

A. In reviewing the electric logs between Koch's wells in the tight formation area and some of the other better wells, there was no apparent difference between these at all.

Now many of the older wells do not have our modern suite of logs. They have neutron or just an electric log in some cases.

But there we did not find an apparent change in formation characteristics between the two; just the permeability deteriorates in the tight formation area here.

MR. HIGGINS: And this case per se is not based on geologic trends?

A. No, not at all.

MR. NUTTER: I think Mr. Friend answered awhile ago, he said that they put Koch's acreage under study and then squared it off.

A. That's correct.

MR. NUTTER: And kicked one section out because it was fully developed, and extended it north to the Colorado line to square it off.

But there's no -- there's no suggestion that this is any geological line or engineering parameters change, or anything like that; just the area you chose to study.

A. That's right.

MR. NUTTER: You don't have a tight sand down here in this well in the southwest quarter of Section 12, I don't think, do you?

The one with the 7-billion cumulative?

A. There might be a fracture there, a natural fracture.

MR. NUTTER: Are there any further questions of Mr. Friend?

MR. CHAVEZ: Yes, I'd like to ask a question.

MR. NUTTER: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Friend, the stimulation treatments that you put on these wells, do you have any estimate as to what the effective increase in permeability would be with the stimulation you put on the wells?

A. We did run a post-stimulation build-up test on one well. We got a permeability of .18 millidarcies. That was on the Gardner No. 3. It is the same well that we feel had a pre-stimulation permeability of .0012, or something in that range.

Q. Well, didn't the expected increase, did it come from this stimulation of the well?

A. I believe it is.

Q. The data that you used on your calculation of permeability, let's see, you used the Exhibit Seven --

you used the thickness, let's see, you ran it on the production of the Gardner 1; you used the formation thickness from the Gardner 3?

A. Yes, because we did not have a density log or any type of porosity log for the Gardner No. 1, and we could not pick porosity or net pay, so we used the closest offset.

Q. Yeah, but you had a perforated interval, didn't you?

A. It was completed open hole.

Q. Oh, completed open hole?

A. Yes, sir.

Q. Okay.

MR. CHAVEZ: That's all.

MR. NUTTER: Are there any other questions? Mr. Friend may be excused.

Do you have anything further, Mr. Carr?

MR. CARR: Nothing, Mr. Nutter.

MR. NUTTER: Does anyone have anything they wish to offer in case Number 7209?

We'll take the case under advisement and the hearing is adjourned.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd C.S.R.

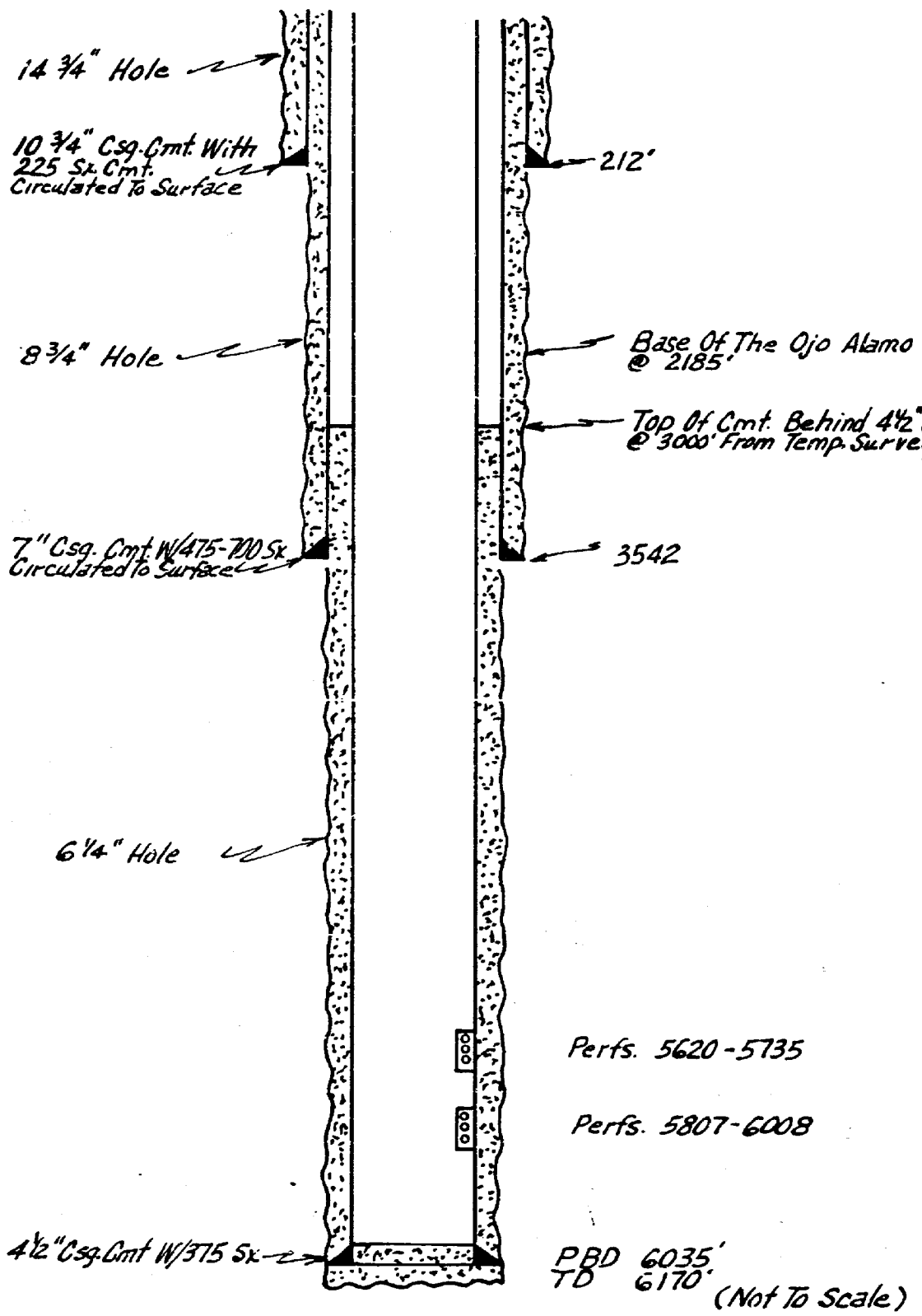
I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7209 heard by me on 3/25 1981.

Oil Conservation Division, Examiner

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 5
CASE NO. 7209

EXHIBIT No. 5
KOCH - No. 4-A Gardner
Sec. 25-T32N-R9W
San Juan Co., New Mexico
GL 6670 - KB 5800



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BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. A
CASE NO. 7209

KOCH INDUSTRIES, INC.

RATTLESNAKE CANYON TIGHT FORMATION AREA

The recommended Rattlesnake Canyon Mesaverde tight gas formation area is located in north-central San Juan County, adjacent to the Colorado state line on the southwest flank of the San Juan Basin. The proposed area includes the following lands:

T32N-R8W, Sections 7, 18-19, 30-31

T32N-R9W, Sections 10-15, 22-27, 34-35

This area is shown on Exhibit No. 1, a structure map of the Green Marker. This marker lies approximately 350' above the top of the Cliff House member of the Mesaverde, and is persistent across the mapped area. The map shows the regional dip to the northeast at generally less than $1/2^{o}$ across the proposed area.

Exhibit No. 2 is a type log of the Mesaverde formation in this area and shows the three members of the formation, the Cliff House, Menefee, and Point Lookout. The vertical limits of the Blanco Mesaverde gas pool in this area have been defined by the New Mexico Oil Conservation Division to be from the Huefanito Bentonite in the Lewis shale to a point 500' below the top of the Point Lookout member. The Huefanito Bentonite is a marker 816' uphole from the Green Marker. The Cliff House and Point Lookout members are considered to be the main producing zones in the field, but the less continuous sands of the Menefee also contribute to the overall production of the Mesaverde. In the proposed tight gas sand area, the Cliff House averages only about 50' thick and the pososity ranges from less than 4% to 15%. The Menefee in this area ranges from 230' to 290' thick and porosity varies from less than 3% to 17%. The main Point Lookout sands are about 150'-200' thick in this area although significant stringers of sand may be found as low as 300' below the top of the member. The porosity of the Point Lookout in the type well ranges from 3% to 14% and is considered typical

of the area. The average porosity for the sands of all three members is about 8%.

Exhibits No. 3 and 4 are west-east and southwest-northeast stratigraphic cross-sections through the area. They show the continuity of the Cliff House and Point Lookout sands across the area. They also show the irregularity of the sands in the Memefee.

The Point Lookout consists of nearshore or shoreline sands deposited during an overall regression of the Mancos Sea. The sand buildups represent periods of stillstand during the regression. The sands have been described as: light gray, very fine to fine grained, well cemented, often an argillaceous matrix, with poor visible porosity.

The Menefee represents a period of non-marine deposition during Mesaverde time. Environments of deposition include coal-forming swamps and coastal plain deposits. Numerous coals, silts, shales, and channel sands can be observed in a typical Menefee section. Reservoir quality often is similar to that of the Cliff House and Point Lookout sands, but the continuity and predictability of these Menefee sands is poor. Binocular description of the sands is not appreciably different than that of the Point Lookout.

The Cliff House consists of widespread shoreline sands deposited during transgression of the Lewis Sea. The sand buildups represent stillstands during that transgression. Again, binocular description of these sands is very similar to that of the Point Lookout and Menefee members.

The Cliff House in the proposed area is nearly to the point where it has pinched out completely, and within the 50' interval only about 10' is potentially productive. The gross interval (230'-280') of the Menefee contains only an average of 2 to 3 benches of potentially productive sand whereas to the south wells have a Menefee section of 1000' or more with several productive

intervals. The point is that in this area it is also near its seaward productive limit. Overall this area is near the productive limit of the various members of the Mesaverde. With relatively few objective zones in this area, the risk of drilling an uneconomic well is considerably greater than even a few miles to the south.

FRESH WATER PROTECTION

State and federal regulations assure that development drilling to the Mesaverde formation will not adversely affect any fresh water aquifers in the proposed tight formation area. Regulations require that casing programs be designed to seal off potential water bearing formations thus separating them from oil and gas bearing formations. Potential fresh water formations exist down to the base of the Ojo Alamo formation.

Exhibit No. 5 illustrates a typical casing program for Koch's wells in the area. A 14 3/4 inch hole is drilled to approximately 200 feet and 10 3/4 inch casing cemented in place with cement circulated to the surface. An 8 3/4 inch hole is drilled to approximately 3500 feet and 7 inch casing set with cement again being circulated to the surface. A 6 1/4 inch hole is gas drilled to total depth and 4 1/2 inch casing set and cemented with enough cement to extend up into the 7 inch casing. A temperature survey is run to determine the top of the cement. The exhibit shows that it is 4000 feet between the base of the Ojo Alamo and the intervals normally perforated, therefore the chance of a frac fluid or gas being communicated with fresh water is extremely remote. In the event that they are communicated Koch would squeeze the channel or perform whatever remedial work that would be required to isolate the intervals.

The upper 3500 feet of the well is drilled with natural mud which will not contaminate fresh water zones. During completion operations, each zone is broken down with approximately 500 gallons of 7 1/2 percent acid prior to frac. This small amount of acid will do little to contaminate an extensive aquifer, even in the

unlikely event it did communicate with a fresh water zone. Frac fluid consists of fresh water with approximately two percent KCl added. Again this fluid would do little to contaminate an extensive aquifer.

The good cementing practices and the casing design is such that any fresh water interval is protected by cement and at least one string of casing. Circulating cement to surface on the first two casing strings insures a good cement job. This along with the long interval between any fresh water zone and the producing formation makes it unlikely that fluids from the productive zones will come in contact with fresh water.

WELL DATA

Exhibit No. 6 is a production map of the tight formation and many of the surrounding wells. Anticipated ultimate production expected from the Koch operated wells as determined by Ryder Scott Petroleum Engineers (a Houston Texas based consulting firm) is shown. The map shows that to the south and west the cumulative gas production has been more than in the tight sand area.

Well data for wells not operated by Koch are shown on Exhibit No. 7. These wells were drilled prior to 1960 and all were stimulated. No pre stimulation rates were reported for the wells. Post stimulation rates range from a low of 145 MCFPD to a high of 3483 MCFPD AOF.

Exhibit No. 8 lists the Koch operated wells in the tight formation area. The first well was drilled in 1954. No additional wells were drilled until 1976. The results from the wells drilled in 1976 were disappointing and development was suspended until 1980 when two additional step out wells and one infill well was drilled. Koch has again stopped drilling due to poor economics.

As many as seven or eight additional wells can be drilled on the Koch acreage alone if the economics are more favorable.

The only Koch operated well to produce measurable gas prior to stimulation was Gardner No. 1. The details of this test are not known, however it is doubtful that this represented a stabilized rate. All of the wells were drilled with gas, which provided a continuous test. The Gardner No. 4 was the only well with a slight show of gas while drilling. Gardner Well No. 5 produced at a rate too small to measure prior to stimulation.

Various types of well completions have been tried by Koch in an attempt to increase gas production. Each interval shown on the Exhibit has been frac treated alone. The number of intervals have been varied from two to three. Total frac treatments range in size from 80,000 pounds to massive 293,000 pounds.

The short term post stimulation flow rates should not be considered as representative of a wells long term ability to produce. Producing rates show a rapid decline following the initial potential.

The most recent wells drilled, Gardner No. 4-A and 5 cost $489,000 and $407,000 respectively to drill and complete. The respective amount paid to service companies to break down and frac the wells was $67,000 and $74,000.

PERMEABILITY CALCULATIONS

In a tight reservoir such as the Mesaverde in the tight formation area, it is difficult to establish pre stimulation permeability. The wells will not flow at a stable rate to permit the normal build-up analysis. None of the wells were cored, therefore adjusted or measured core permeabilities can not be used to determine permeability. The most convincing data available is the fact that the massive sands will not produce at sustained rates prior to stimulation and will not maintain high rates after stimulation.

The one pre stimulation flow rate available was used to calculate permeability using Darcy's Law. As mentioned earlier, this test data from Gardner Well No. 1 were not well documented. Certain assumptions were necessary to perform these calculations. It was assumed that the 47 MCFPD rate was a stabilized rate and the flowing wellhead pressure was at, or near atmospheric pressure. A porosity log was not run on the well, therefore a net pay of 149 feet based on Gardner Well No. 5 was assigned to the well.

Exhibit No. 9 presents the calculations used to determine permeability based on the test rate. The results show a permeability of 0.0208 Md. This is probably high as the rate was probably not stable.

Actual well test data from Gardner Well No. 3 were used in a computer program designed to calculate permeability based on performance. The basis of the analysis is from a paper by Gringarten, Ramey and Raghaven, which was published in Volume 257 of the AIME Transactions. Solution of the problem was made possible by the use of the Garrett Computing Systems' program - Gas Well Performance Simulation, which is obtaining industry-wide acceptance. Copies of the Gringarten et. al. and the Garrett documentation are included for easy reference by the U.S.G.S. and State of New Mexico staffs.

Basic assumptions in the computer program include a single uniform producing interval in a homogeneous reservoir. Of course the Mesaverde formation does not meet this requirement and the fact that intervals are frac treated separately will result in non-uniform fracture lengths. However, by entering data as though the reservoir is uniform should result in an indication of the permeability.

Exhibit No. 10 shows the test data, calculated flow rates and required fracture lengths for various permeabilities. Although an exact solution could not be obtained, it is reasonable to expect that the reservoir in situ gas permeability is between 0.001 and 0.002 Md.

ECONOMIC CONSIDERATIONS

Completion date, cumulative production and the current status of wells completed in the Mesaverde Formation in the proposed tight formation area are shown in Exhibit No. 11. Remaining reserves, as determined by Ryder Scott Engineers, are included for the Koch operated wells. A comparison of the completion date and the current status shows the rapid early production decline experienced by Gardner Wells 2, 3, 3-A and 4.

Exhibit No. 12 presents the estimated cost to drill and complete a trouble free Mesaverde well in the tight sand area. The last two wells drilled cost more than the $400,700 estimate.

Assumptions and results of an economic analysis for a well drilled in the tight gas formation area are shown in Exhibit No. 13. Production data used for the projection was taken from the first 25 years of history from Gardner Well No. 1. Page 1 of the exhibit shows that the discounted cash flow rate of return is 7 percent and the payout period is 9.4 years before income tax. These values are reduced to 6 percent rate of return with a 10.4 year payout

after income tax. Since no drilling difficulties or risk are included in the analysis, the actual parameters will be less attractive than shown. The long payout periods and low rates of return are not acceptable.

Section 107 tight gas formation prices will provide more favorable economics which will result in additional development in the tight formation area. An after tax analysis based on a $4.778/MCF Section 107 gas price resulted in a 20 percent rate of return and a 4 year payout which, while not excessive, is an acceptable rate of return.

CONCLUSIONS

Exhibit No. 14 presents a summary of pertinent reservoir data for the Mesaverde tight gas formation area. The average porosity of 11.3 percent represents a porosity based on an 8 percent cut off. Although a definite permeability value was not determined, the permeability is less than 0.1 Md and probably less than 0.02 Md. The exhibit also shows that the wells do not produce oil.

The Mesaverde formation in the proposed area meets the guidelines necessary to qualify the area for tight formation designation. These are:

1) The in situ permeability is less than 0.1 Md
2) The stabilized gas production rate is less than the 163 MCFPD maximum permitted for wells completed below 5000 ft.
3) No well will produce more than five barrels of oil per day.
4) Fresh water sands in the area will be adequately protected during drilling, completion and production operations.

In addition, wells completed in the area will show unfavorable economics with the existing gas price. The incentive of a higher gas price will result in additional wells being drilled.

KOCH INDUSTRIES, INC.

NUMBER, NAME AND PURPOSE

OF EACH EXHIBIT

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
1	Structure Map	Show structure in The Tight Formation Area
2	Type Log	Show log characteristics and depth of Mesaverde Formation
3	Cross Section A-A'	Show Mesaverde Formation development in a northwest-southeast direction
4	Cross Section B-B'	Show Mesaverde Formation development in a northeast-southwest direction
5	Schematic of Gardner Well No. 4-A	Show casing and cementing procedures to protect fresh water zones
6	Completion and Production Map	Show cumulative production from Mesaverde wells in and around the tight formation area, and expected ultimate production from Koch's wells
7	Wells Not Operated by Koch Industries	Show spud date, pre stimulation rate, type of stimulation and post stimulation rate of wells not operated by Koch
8	Flow Rates and Fracturing Information, Koch Operated Wells	Show spud date, pre stimulation rate, type of stimulation and post stimulation rate of wells operated by Koch
9	Calculated Permeability Based on Well Test From Gardner No. 1	Show calculated permeability from pre stimulation test
10	Calculated Permeability Based on Reservoir Simulation	Show calculated permeability for Gardner well No. 3 based on the Garrett Gas well performance simulation program

KOCH INDUSTRIES, INC.

NUMBER, NAME AND PURPOSE

OF EACH EXHIBIT

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

page 2)

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
11	Well Status and Reserves	List cumulative production, production and current status of all wells in the tight formation area and estimated ultimate production from Koch operated wells
12	Cost Estimate to Drill and Complete a Mesaverde Well	Show cost data used in economic calculations
13	Economics Based on Gardner Well No. 1 Production History	Show economics based on actual production history
14	Pertinent Reservoir Data	Show expected reservoir properties

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 7
CASE NO. 7209

EXHIBIT NO. 7

WELLS NOT OPERATED BY KOCH
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION RATE	TYPE OF STIMULATION	POST STIMULATION RATE MCFPD
Northwest Pipeline Corp.						
San Juan 32-8 Unit No. 24	A-19-32N-8W	6/20/57	5366 - 5816	NR*	Sand-Water Frac	1708 AOF
El Paso Natural Gas Company						
San Juan 32-9 Unit No. 10	G-34-32N-9W	9/8/53	5395 - 5960 OH	NR	Shot w/165 qts	145 IP
San Juan 32-9 Unit No. 11	A-14-32N-9W	10/16/53	5763 - 6280 OH	NR	Shot w/1335 qts	648 IP
San Juan 32-9 Unit No. 52	M-13-32N-9W	12/1/57	5718 - 6228	NR	Sand-Water Frac	288 IP
San Juan 32-9 Unit No. 53	M-27-32N-9W	8/5/57	5672 - 6234	NR	Sand-Water Frac	.2818 AOF
San Juan 32-9 Unit No. 54	L-14-32N-9W	11/11/57	5748 - 6238	NR	Sand-Water Frac	3483 AOF
San Juan 32-9 Unit No. 66	M-10-32N-9W	5/27/58	5930 - 6398	NR	Sand-Water Frac	1811 AOF

* NR - Not Reported

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 8
CASE NO. 7209

EXHIBIT #8

FLOW RATES AND FRACTURING INFORMATION, KOCH OPERATED WELLS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

WELL NAME AND NUMBER	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION FLOW RATE MCF/D	POST STIMULATION FLOW RATE MCF/D	SIZE FRAC TREATMENT GALS	# SAND
Gardner No. 1	M-35-32N-9W	6-4-54	5192-6100	47	1503	2880 quarts	
Gardner No. 2	G-31-32N-8W	3-25-76	5760-5862 5518-5666 5078-5464	No gas while drilling	965	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3	N-31-32N-8W	11-23-76	5755-5996 5419-5682 5059-5160	No gas while drilling	2290	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3-A	P-31-32N-8W	1-27-80	5706-5847 5414-5626	No gas while drilling	1304	80,000 30,000 110,000	80,000 30,000 110,000
Gardner No. 4	M-25-32N-9W	12-8-76	5772-5946 5538-5592 5083-5162	Slight show of gas while drilling	3200	50,000 20,000 10,000 80,000	50,000 20,000 10,000 80,000
Gardner No. 4-A	P-25-32N-9W	9-4-80	5807-6008 5620-5735	No gas while drilling	2120	200,000 106,500 306,500	200,000 93,000 293,000
Gardner No. 5	M-26-32N-9W	9-23-80	5644-5793 5440-5531	TSTM No gas while drilling	1800	160,000 60,000 220,000	150,000 60,000 210,000

Note: All wells were drilled with gas which provided a continuous test

EXHIBIT NO. 9

CALCULATED PERMEABILITY BASED
ON WELL TEST FROM GARDNER NO. 1
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation at permeability with Darcy's Law

$$k = \frac{QU_gTZ \ln(0.61\ r_e/r_w)}{703\ h(Pe^2 - Pf^2)}$$

Where:

- Q = gas flowing rate, SCF/D - 47,000
- U_g = gas viscosity, cp calculated as 0.0142
- T = reservoir temperature, R^o - 610
- Z = gas compressibility calculated as 0.9091
- r_e = drainage radius of 1490ft. for 160 acres
- r_w = wellbore radius of 0.26 ft.
- h = net pay estimated at 149 feet from Gardner well No. 5. A porosity log was not run on the Gardner No. 1.
- P_e = static shut-in reservoir pressure at drainage radius r_e, psia calculated as 1177
- P_f = Flowing subsurface pressure, psia estimated as 45 psia

k is permeability in Darcies

$$k = \frac{(47{,}000 \times 0.0142 \times 610 \times 0.9091 \ln(0.61 \times 1490/0.26)}{703 \times 149 \times (1177^2 - 45^2)}$$

$k = 0.0000208$ D.
$= 0.0208$ md

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 9
CASE NO. 7209

EXHIBIT NO. 10

CALCULATED PERMEABILITY BASED ON RESERVOIR SIMULATION
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

INPUT DATA FROM GARDNER WELL NO. 3

Porosity - 11.7%
Net Pay - 250 ft.
Liquid Saturation - 55%
Reservoir Temperature - 150° F
Drainage Area - 160 acres
Test Data -

Date	Rate MCFPD	Flowing WHP, Psi
8-17-79	Date of initial production	
8-23-79	1300	450
9-4-79	697	320
5-20-80	143	350
2-10-80	115	295

RESULTS

Fracture Half Length, ft.	Permeability Md	*1300	*697	*143	*115
750	0.002	1566	1016	222	173
600	0.002	1255	808	185	145
625	0.0013	1050	675	148	115
650	0.00125	1072	688	151	116
650	0.00122	1058	679	148	115
638	0.00126	1055	677	149	115

A reasonable history match is shown for all except the first flow period with permeabilities from 0.00122 to 0.0013 Md. Calculations are made assuming a homogenous reservoir.

* Test rates. All calculated rates are at the measured wellhead pressures.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koost EXHIBIT NO. 10
CASE NO. 7209

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 11
CASE NO. 7209

EXHIBIT NO. 11

WELL STATUS AND RESERVES
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	DATE OF INITIAL PRODUCTION	CUMULATIVE PRODUCTION 10-31-80, MCF	ESTIMATED REMAINING RESERVES, MCF	ESTIMATED ULTIMATE RESERVES, MCF	OCTOBER,1980 STATUS
Koch Industries, Inc.					
Gardner No. 1	9-54	426,694	95,306	522,000	564 MCF/M
Gardner No. 2	8-79	77,104	518,896	596,000	3712 MCF/M
Gardner No. 3	8-79	102,071	427,929	530,000	4225 MCF/M
Gardner No. 3-A	9-80	25,172	504,828	530,000	21676 MCF/M
Gardner No. 4	8-79	93,799	269,201	363,000	2807 MCF/M
Gardner No 4-A	----	0	480,000	480,000	Waiting on PL connection
Gardner No. 5	----	0	480,000	480,000	Waiting on PL connection
Northwest Pipeline Corp.					
San Juan Unit 32-8 No. 24	12-57	205,693			654 MCF/M
El Paso Natural Gas Company					
San Juan 32-9 Unit No. 10	1-54	1,840	0	1,840	P & A
San Juan 32-9 Unit No. 11	4-54	2,366	0	2,366	P & A
San Juan 32-9 Unit No. 52	8-57	34,896	0	34,896	P & A
San Juan 32-9 Unit No. 53	1-58	395,430			742 MCF/M
San Juan 32-9 Unit No. 54	5-58	656,174			1255 MCF/M
San Juan 32-9 Unit No. 66	1-59	174,879			287 MCF/M

EXHIBIT #12

OIL EXPLORATION COMPANY

DETAIL WELL ESTIMATE

LEASE NO. _____ AFE NO. _____ OUR W. I. _____

LEASE NAME AND WELL NO. Gardner Area LOCATION _____

DISTRICT _____ COUNTY San Juan STATE New Mexico FIELD OR AREA _____

EST. T. D. 6200 FT. OPERATOR Koch Exploration DATE February, 1981

		Producer	Dry Hole
Drilling Intangibles:			
1	**LOCATION EXPENSE:**		
	DIG PITS $ 2,000 FILL PITS $ 2,000 ROADS-BRIDGES $ 4,000		
	DRGD.-GRADE $ _____ SURV. LOCATION $ 300 DAMAGES $ 500		
	STATE-MISC. FEES $ _____ MISC. (LIST) $ _____		
	FEATURE TOTAL	$ 8,800	$ _____
11	**RIG COSTS:** 17 days @ 5,800		
	DRILLING _____ FT. AT $ _____/FT. $ _____ DAY WORK $ 98,600		
	BITS-REAMERS $ 6,000 WATER $ _____ MIRT-NORT $ 8,000		
	COMPRESSORS $ _____ CABLE TOOLS $ _____ FUEL-SUPPLIES $ _____		
	BOILER CHG $ _____ SWAB UNIT $ 5 days @ 1,400 = 7,000		
	MISC. (LIST) $ _____		
	FEATURE TOTAL	$ 131,600	$ _____
20	**CEMENT AND SERVICES:**		
	CEMENT AND SERVICE: SURFACE $ 700 INTR. $ 5,100 PROD $ 2,000		
	FLOATS $ _____ CENTRALIZERS $ _____ GUIDES $ _____		
	STAGE TOOLS $ _____ SCRATCHERS $ _____ PLUGGING $ _____		
	SQUEEZES $ _____ MISC (LIST) $ _____		
	FEATURE TOTAL	$ 7,800	$ _____
21	**DRILLING FLUIDS:**		
	MUD $ 15,000 CHEMICALS $ _____ OIL $ _____		
	MISC. (LIST) $ _____		
	FEATURE TOTAL	$ 15,000	$ _____
22	**WELL SURVEYS AND TESTING:**		
	CORING $ _____ CORE HEADS $ _____ TEMP. SURV. $ 300		
	CALIPER SURV. $ _____ ELEC. SURV. $ 15,300 MUD LOG $ _____		
	D. S. T. S _____ AT $ _____ EA. $ _____ RADIATION LOG $ _____		
	MISC. (LIST) $ _____		
	FEATURE TOTAL	$ 15,600	$ _____
23	**SPECIAL SERVICES:**		
	PERFORATING $ 10,000 PLUGS-RETAINERS $ _____ ACID $ _____		
	FRAC. $ 65,000 MISC. TOOL RENTAL $ _____		
	FEATURE TOTAL	$ 75,000	$ _____
30	**LABOR AND SUPERVISION:**		
	CO. LABOR $ _____ SUPV.-PERS. EXP. $ _____ OVERHEAD $ _____		
	DIST EXP. $ _____ CONTRACT LABOR $ _____ COMMUNICATION $ _____		
	FEATURE TOTAL	$ _____	$ _____
40	**TRANSPORTATION:**		
	CO. CARS $ 500 AIR TRAVEL $ _____		
	TRUCKING (CASING, TUBING, CABLE TOOLS) $ 10,000		
	FEATURE TOTAL	$ 10,500	$ _____
41	**OTHER COSTS:**		
	(ITEMIZE) _____		
	FEATURE TOTAL	$ _____	$ _____
45	**CONTINGENCY:** 15%	$ 39,600	$ _____
	TOTAL INTANGIBLES	$ 303,900	$ _____
Well Equipment:			
51	**CASING AND TUBING (SIZE, WT., GRD., CPLG., NEW OR USED)**		
	200 FT. OF 28# 10-3/4" AT $ 17.91 /FT. $ 3,600		
	3600 FT. OF 20 & 26# 7" AT $ 8.00 /FT. $ 28,800		
	6200 FT. OF 10.5# 4-1/2" AT $ 5.15 /FT. $ 31,900		
	6000 FT. OF 4.7# 2-3/8" AT $ 2.92 /FT. $ 17,500		
	FEATURE TOTAL	$ 81,800	$ _____
52	**CASING HD.** $ 1,000 XMAS TREE OR PUMPING CONNECTION $ 2,000	$ 3,000	$ _____
53	**PUMPING UNIT** $ _____ ENGINE OR ELECTRIC MOTOR $ _____	$ _____	$ _____
55	**SUCKER RODS** _____	$ _____	
	PUMP $ _____ POLISHED ROD $ _____ FEATURE TOTAL	$ _____	$ _____
62	**TANKS** 1 AT $ 3,850 EA. $ _____ BUILD BATTERY $ _____		
	FLOWLINES 100 FT. OF _____ AT $ 2.50 PER FT. $ 250		
	LAY FLOWLINES $ 200 FENCING-PAINTING $ _____ VALVES-FITTINGS $ 200		
	FEATURE TOTAL	$ 4,500	$ _____
63	**SEPARATOR** $ _____ HTR. TRTR. $ _____ DEHYDRATION EQUIP. $ _____	$ _____	$ _____
71	**METERING EQUIP.** $ _____	$ _____	$ _____
72	**OTH** _____	$ 7,500	$ _____
	TOTAL TANGIBLES	$ 96,800	$ _____
	TOTAL ESTIMATE	$ 400,700	$ _____
	LESS CONTRIBUTIONS	$ _____	$ _____
	NET WELL COST	$ _____	$ _____
	OUR NET COST	$ _____	$ _____

REMARKS _____

ORIGINATED BY _____ DATE _____ APPROVED _____ DATE _____

APPROVED _____ DATE _____ APPROVED _____ DATE _____

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 12
CASE NO. 7209

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 13
CASE NO. 7209

EXHIBIT NO. 13

ASSUMPTIONS AND RESULTS OF ECONOMIC CALCULATIONS

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

ASSUMPTIONS

Drilling and Completion Costs, $	400,700
Expense Interest, %	100
Royalty Interest, %	15
Yield, BBL/MMCF	0
Gas Price, $/MCF	2.389
Severance Tax, %	8
Operating Costs, $/well/yr.	4800
Income Tax Rate, %	48.7
Time Projected, yrs.	25

Producing Rate - Same as Actual Production From Gardner Well No. 1 (413 MMCF in 25 yrs)

RESULTS

Before Income Tax Results:

Discounted Cash Flow Rate of Return, %	7
Payout, yrs.	9.4
Cash Flow, $	259,796

After Income Tax Results:

Discounted Cash Flow Rate of Return, %	6
Payout, yrs.	10.4
Cash Flow, $	142,960

EXHIBIT NO. 13
ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

CURRENT DATE 02/04/81

INVESTMENT ANALYSIS GARDNER AREA WELL NO 1 AT TODAYS COSTS AND PRICE PROJECT LIFE 25 YEARS TAX RATE .48700 DPL .00

INVESTMENT REQUIRED

YEAR	LAND	DEPRECIABLE	DEPLETABLE	WORKING CAP	GOODWILL	TOTAL	SALV PCT	METHOD	INVEST LIFE	TAX CREDIT SUBJ TO INV	PROJECT RECOVERY	IDC PCT	YR
0	0	96,800	303,900	0	0	400,700	.000	4	25.0	96,800	0	.999	0
***	0	96,800	303,900	0	0	400,700				96,800	0		

LOANS REQUIRED

YEAR	PRINCIPAL	PAYOFF PERIOD	INTEREST RATE	DEBT LIQUIDATION	PAYMENT FREQUENCY
TOTAL	0			0	

INPUT VARIABLES -

WORKING INTEREST	BPO	1.0000000			
REVENUE INTEREST	BPO	.8500000			
PRODUCTION TAX RATES	GAS	.0800000	COND	.0000000	
PRINCIPAL PRODUCT	GAS				

REVENUE & COST EXTENSIONS

YEAR	GROSS DAILY GAS - MCF	NET ANNUAL GAS - MCF	GAS PRICE	REVENUE GENERATED	GROSS DAILY COND - STB	NET ANNUAL COND - STB	COND PRICE	REVENUE GENERATED	OPERATING COST	PRODUCTION TAX	OVERHEAD COST
0- 1	95	29,776	2.3890	71,135					4,800	5,691	
1- 2	95	29,740	2.3890	71,049					4,800	5,684	
2- 3	88	27,311	2.3890	65,246					4,800	5,220	
3- 4	76	23,762	2.3890	56,767					4,800	4,541	
4- 5	71	22,257	2.3890	53,172					4,800	4,254	
5- 6	58	18,184	2.3890	43,442					4,800	3,475	
6- 7	41	12,964	2.3890	30,971					4,800	2,478	
7- 8	50	15,574	2.3890	37,206					4,800	2,976	
8- 9	58	18,020	2.3890	43,050					4,800	3,444	
9-10	39	12,151	2.3890	29,029					4,800	2,322	
10-11	28	8,917	2.3890	21,303					4,800	1,704	
11-12	24	7,548	2.3890	18,032					4,800	1,443	
12-13	33	10,486	2.3890	25,051					4,800	2,004	
13-14	29	9,257	2.3890	22,115					4,800	1,769	
14-15	36	11,255	2.3890	26,888					4,800	2,151	
15-16	44	13,801	2.3890	32,971					4,800	2,638	
17-18	44	13,725	2.3890	32,787					4,800	2,623	
18-19	29	9,026	2.3890	21,563					4,800	1,725	
19-20	42	13,160	2.3890	31,439					4,800	2,515	
20-21	26	8,287	2.3890	19,798					4,800	1,584	
21-22	22	6,890	2.3890	16,460					4,800	1,317	
22-23	22	7,002	2.3890	16,728					4,800	1,338	
23-24	17	5,407	2.3890	12,917					4,800	1,033	
24-25	17	5,545	2.3890	13,247					4,800	1,060	
TOTAL	413,180	353,113		848,365					120,000	67,869	
	GROSS BBLS (MCF)							GROSS BBLS(MCF)			

EXHIBIT NO. 13

ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

CASH FLOW CALCULATIONS

YEAR	TOTAL INCOME	TOTAL COSTS	DEPREC-IATION	INTEREST	INCOME TAX	TAX DEPLETION	BOOK DEPLETION	NET INCOME	DEBT LIQUIDATION	CASH FLOW
0										400,700-*
0- 1	71,135	10,491	8,117		132,099-		25,481	159,145		192,743
1- 2	71,049	10,484	8,107		25,547		25,451	1,460		35,018
2- 3	65,246	10,020	7,445		23,269		23,372	1,140		31,957
3- 4	56,767	9,341	6,477		19,942		20,335	672		27,484
4- 5	53,172	9,054	6,067		18,531		19,047	473		25,587
5- 6	43,442	8,275	4,957		14,712		15,561	63-		20,455
6- 7	30,971	7,278	3,534		9,817		11,094	752-		13,876
7- 8	37,206	7,776	4,245		12,265		13,327	407-		17,165
8- 9	43,050	8,244	4,912		14,558		15,421	85-		20,248
9-10	29,029	7,122	3,312		9,056		10,398	850-		12,851
10-11	21,303	6,504	2,431		6,023		7,631	1,286-		8,776
11-12	18,032	6,243	2,058		4,739		6,459	1,467-		7,050
12-13	25,051	6,804	2,858		7,494		8,973	1,078-		10,753
13-14	22,115	6,569	2,523		6,342		7,921	1,240-		9,204
14-15	26,893	6,951	3,068		8,215		9,631	977-		11,722
15-16	32,971	7,438	3,762		10,602		11,810	641-		14,931
16-17	35,997	7,680	4,107		11,790		12,894	474-		16,527
17-18	32,789	7,423	3,741		10,531		11,745	651-		14,835
18-19	21,563	6,525	2,460		6,125		7,724	1,271-		8,913
19-20	31,439	7,315	3,587		10,002		11,262	727-		14,122
20-21	19,798	6,384	2,259		5,432		7,091	1,368-		7,982
21-22	16,460	6,117	1,878		4,122		5,896	1,553-		6,221
22-23	16,728	6,138	1,909		4,228		5,992	1,539-		6,362
23-24	12,917	5,833	1,474		2,732		4,627	1,749-		4,352
24-25	13,247	5,860	1,512		2,861		4,745	1,731-		4,526
TOTAL	848,365	187,869	96,800		116,836		303,888	142,972		142,960

* = NET CASH INVESTMENT OR SALVAGE

AFIT
DCF RATE OF RETURN: 5.98 PER CENT
PAYBACK PERIOD 10.37 YEARS

BFIT
DCF RATE OF RETURN 6.98 PER CENT
PAYBACK PERIOD 9.43 YEARS

EXHIBIT NO. 14

PERTINENT RESERVOIR DATA

Datum Depth, Ft.	5750
Original Reservoir Pressure, Psia	1177
Reservoir Temperature, ^{o}F	150
Average Net Pay, ft. (Koch's Wells)	156
Average Porosity, % (Koch's Wells)	11.3
Expected Permeability, Md	<0.02
Oil Production, BOPD	None

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 14
CASE NO. 7209

Unsteady-State Pressure Distributions Created by a Well With a Single Infinite-Conductivity Vertical Fracture

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MEMBER SPE-AIME
HENRY J. RAMEY, JR.
R. RAGHAVAN**
MEMBERS SPE-AIME

U. OF CALIFORNIA AT BERKELEY
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STANFORD U.
STANFORD, CALIF.

INTRODUCTION

During the last few years, there has been an explosion of information in the field of well-test analysis. Because of increased physical understanding of transient fluid flow, it is possible to analyze the entire pressure history of a well test, not just long-time data as in conventional analysis.[1] It is now often possible to specify the time of beginning of the correct semilog straight line and determine whether the correct straight line has been properly identified. It is also possible to identify wellbore storage effects, and the nature of wellbore stimulation as to permeability improvement, or fracturing, and to quantitatively analyze those effects.

Such accomplishments have been augmented by attempts to understand the short-time pressure data from well testing — data that were often classified as too complex for analysis. One recent study of short-time pressure behavior[2] showed that it was important to specify the physical nature of the stimulation in considering the behavior of a stimulated well. That is, stating that the van Everdingen-Hurst infinitesimal skin effect was negative was not sufficient to define short-time well behavior. For instance, acidized (but not acid-fractured) and hydraulically fractured wells might not necessarily exhibit the same behavior at early times, even though they could possess the same value of negative skin effect.

In the same manner, hydraulic fracturing leading to horizontal or vertical fractures could produce the same skin effect, but with possibly different short-time pressure data. This could then provide a way to determine the orientation of fractures created by this type of well stimulation. In fact, it is generally agreed that hydraulic fracturing usually results in one vertical fracture, the plane of which includes the wellbore. Most studies of the flow behavior for a fractured well consider vertical fractures only.[3-11]

Yet it is also agreed that horizontal fractures *could* occur in shallow formations. Furthermore, it would appear that notch-fracturing would lead to horizontal fractures. Surprisingly, no detailed study of the horizontal fracture case had been performed until recently.[12] A solution to this problem was presented by Gringarten and Ramey.[13] In the course of their study, it was found that a large variety of new transient pressure behavior solutions useful in well and reservoir analysis could be constructed from instantaneous Green's functions.[14] Possibilities included a well with a single vertical fracture in an infinite reservoir, or at any location in a rectangle.

Although similar cases had been studied before by van Everdingen and Meyer,[11] and by Russell and Truitt,[8] there were confusing differences in their respective results, and small inconsistencies between the cases of Ref. 8 made short-time analysis impossible. Both explicit and implicit finite-difference solutions and finite-element solutions were made for the vertical fracture case of Russell and Truitt in an attempt to eliminate differences between Refs. 8 and 11, and internal differences between cases in Ref. 8. It was not possible to reach satisfactory conclusions for the short-time performance region with even very long computer runs with *either* finite-difference or finite-element[12] programs. For this reason, it was decided to evaluate analytical solutions to provide a sound basis for short-time analysis of field data. In the course of the work, to provide a direct comparison with the Russell and Truitt data it became necessary to develop analytical solutions for fracture cases in which the fluid entry flux along the fracture caused a constant pressure along the fracture (infinite fracture conductivity). It also appeared worthwhile to evaluate the new solutions so that vertical fracture behavior could be compared with horizontal fracture behavior in infinite reservoirs. The new solutions for vertically fractured wells are especially useful for short-time or type-curve analysis. Such an analysis can provide information concerning permeabilities, fracture

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*Now with French Geological Bureau, Orleans, France
**Now with Amoco Production Co., Tulsa, Okla.
[1]References listed at end of paper.

length, and distance to a symmetrical drainage limit. Combination of short-time analysis with other conventional semilog analytical methods permits an extraordinary confidence level concerning the analysis of field data.

VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

We model a plane (zero-thickness) vertical fracture totally penetrating a horizontal, homogeneous, and isotropic reservoir initially at constant pressure. At time zero, a single-phase, slightly compressible fluid flows from the reservoir into the fracture at a constant total rate. The producing pressure is *uniform* over the fracture (infinite fracture conductivity). The pressure remains constant and equal to the initial pressure as distance from the well becomes infinitely large (infinite reservoir).

An analytical expression for the pressure distribution created by the plane vertical fracture may be obtained by the Green's function and product solution method,[22] using source functions presented by Gringarten and Ramey.[14] The condition of uniform pressure over the fracture at all times is satisfied, as indicated in Ref. 14, by dividing the half-fracture length x_f into M segments of length x_f/M, each with a uniform flux per unit area, q_m, $(m = 1,M)$. The first segment extends from 0 to x_f/M, the second segment from x_f/M to $2x_f/M$, the mth segment from $[(m-1)x_f]/M$ to mx_f/M, and the last segment from $[(M-1)/M]x_f$ to x_f, as shown in Fig. 1. The q_m $(m = 1,M)$ are determined by equating the pressure drops at the center of the segments, which provide $(M-1)$ equations, the mth equation being obtained from the condition of constant total production rate at all times:

$$\begin{cases} \Delta p\left(\frac{2j-1}{2M}\, x_f,\ 0,\ t\right) = \Delta P\left(\frac{2j+1}{2M}\, x_f,\ 0,\ t\right) \quad j=1,M-1 \quad (1) \\ 2\sum_{m=1}^{M} q_m\left(\frac{x_f}{M}\right)h = q_f \quad (2) \end{cases}$$

The pressure drop created by the fracture is obtained from Ref. 14, Table 5:

$$p_i - p_{x,y,t} = \frac{1}{\phi c}\int_0^t \left\{\sum_{m=i}^{M} q_m(\tau)\int_{\frac{(m-1)x_f}{M}}^{\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2+y^2}{4\eta(t-\tau)}\right]dx_w - \sum_{m=1}^{M} q_m(\tau)\left\{\int_{-\frac{(m-1)}{M}x_f}^{-\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2+y^2}{4\eta(t-\tau)}\right]dx_w\right\}\right\} \cdot \frac{d\tau}{4\pi\eta(t-\tau)} \quad (3)$$

The coordinate system in Fig. 1 and Eq. 3 is different from that of Ref. 14, however. A similar scheme has been used by Muskat[15] for the steady-state pressure distribution created by a partially penetrating well, and has been suggested by Burns[16] for unsteady state. In the unsteady state, however, the method seems impractical: it was expected — and confirmed from a numerical simulation[21] — that the flux per unit area of fracture is not constant but varies in time. A system of M equations and M unknowns as represented by Eqs. 1 and 2 should thus be solved at each value of time.

Actually, this is not true practically, and the pressure distribution can be obtained by solving the system of equations only once. The flux distribution in the fracture at various times, as obtained from a numerical simulation, is shown in Fig. 2. It can be seen that the flux distribution is uniform at very early times, then it changes, and finally it reaches a steady state at some extended time, after which flow entering the fracture stabilizes. The pressure during the stabilized flow period is independent of the flux distribution history, and is the same as if the flux distribution had been equal to the final stabilized flux distribution at all times.

An analog to this interesting and useful fact

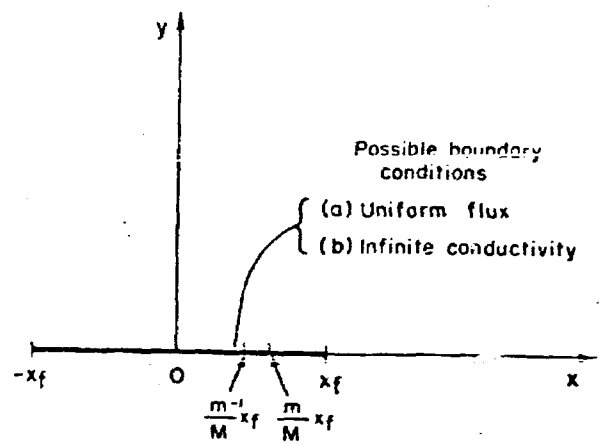

FIG. 1 — VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

occurs in the case of flow to a constant-rate well with wellbore storage. Wellbore storage causes the sand-face production rate to change as a function of time initially. But after some initial period, the sand-face rate reaches the constant surface rate (within a specified percentage), and thereafter the producing pressure is equal to that of a well whose sand-face rate had been constant from the start of production. The pressure is independent of the production history! The same sort of observation was made in another reservoir problem by Carter and Tracy.[23]

By solving the system of Eqs. 1 and 2 for the *stabilized flux distribution* one can obtain a long-time solution for the pressure, whereas an early-time solution can be obtained by assuming uniform flux. We shall show that these also provide an excellent approximation for the pressure distribution at all times.

EARLY-TIME SOLUTION

Integrating Eq. 3 with respect to x_w, the dimensionless pressure drop can be written as

$$p_D(x_D,y_D,t_D) = \int_0^{t_D} \exp -\frac{y_D^2}{4(t-t')_D} \sum_{m=1}^{M} \left(\frac{2q_m(t_D')hx_f}{q_f}\right) \left[\operatorname{erf} \frac{x_D + \frac{m}{M}}{\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D + \frac{m-1}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D - \frac{m}{M}}{2\sqrt{(t-t')_D}} + \operatorname{erf} \frac{x_D - \frac{m-1}{M}}{2\sqrt{(t-t')_D}}\right] \frac{dt_D'}{4[(t-t')_D/\pi]^{1/2}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

The dimensionless space and time variables in Eq. 4 are based on the fracture half-length x_f,

$$x_D = \frac{x}{x_f} \quad ; \quad y_D = \frac{y}{x_f} , \quad \ldots\ldots\ldots\ldots (5)$$

and the dimensionless time and the dimensionless pressure drop are, respectively,

$$t_D = \frac{kt}{\phi\mu c x_f^2} , \quad \ldots\ldots\ldots\ldots\ldots\ldots (6)$$

and

$$p_D(x_D,y_D,t_D) = \frac{2\pi kh}{q_f\mu} (p_i - p_{x,y,t}) . \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

At very early times, the expression

$$\operatorname{erf} \frac{x_D \pm \frac{m}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D \pm \frac{m-1}{M}}{2\sqrt{(t-t')_D}}$$

becomes constant when t_D is small enough.[14] (The constant is 2 if $(m-1)/M < |x_D| < m/M$; unity if $|x_D| = (m-1)/M$ or $|x_D| = m/M$; and zero if $|x_D| < (m-1)/M$ or $|x_D| > m/M$.) Therefore, at very early times the system given by Eqs. 1 and 2 reduces to

$$\begin{cases} \displaystyle\int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \frac{2q_j(t_D')hx_f}{q_f} \cdot \frac{dt_D'}{4[(t-t')_D/\pi]^{1/2}} = \int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \cdot \frac{2q_{j+1}(t_D')hx_f}{q_f} \frac{dt_D'}{4[(t-t')_D/\pi]^{1/2}} , \\ \qquad j=1,\ M-1 \quad \ldots\ldots\ldots (8) \\ \displaystyle\sum_{m=1}^{M} \frac{2q_m(t_D)hx_f}{q_f} = M , \quad \text{all } t_D , \quad \ldots\ldots\ldots (9) \end{cases}$$

which yields

$$q_j = \frac{q_f}{2hx_f} , \quad j=1,M .$$

As indicated by the numerical model, the flux must be uniform over the fracture at very early times, and the early-time solution for the pressure drop function is

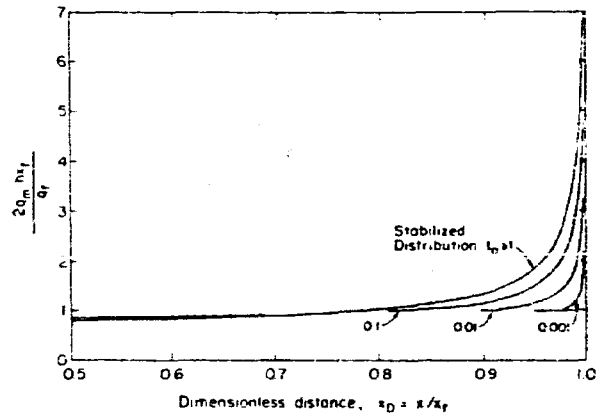

FIG. 2 — FLUX DISTRIBUTION AT VARIOUS TIMES ALONG AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE (NUMERICAL MODEL).

$$p_D(|x_D|<1, y_D, t_D) =$$

$$\int_0^{t_D} \exp\left(-\frac{y_D^2}{4t'_D}\right) \frac{dt'_D}{2(t'_D/\pi)^{1/2}}$$

$$= (\pi t_D)^{\frac{1}{2}} \exp(-y_D^2/4t_D)$$

$$- |y_D| \operatorname{erfc}(|y_D|/2\sqrt{t_D}) \quad \ldots (10)$$

$$p_D(|x_D|>1, y_D, t_D) = 0$$

and, along the fracture,

$$p_{wD}(|x_D|<1, 0, t_D) = \sqrt{\pi t_D}, \quad \ldots (11)$$

which is the conventional result for flow in a linear system. In this case, there is flow into both sides of the fracture.

LONG-TIME SOLUTION

During the stabilized flow period, the q_m's are constant and can be taken out of the integral sign in Eq. 3. Inverting the order of integration in Eq. 3, one obtains

$$p_D(x_D, y_D, t_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} \left\{ \int_{\frac{m-1}{M}}^{\frac{m}{M}} -Ei\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] dx_{wD} \right.$$

$$\left. - \int_{-\frac{m}{M}}^{-\frac{m-1}{M}} -Ei\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] dx_{wD} \right\}, \quad \ldots (12)$$

with

$$\sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} = M \quad \ldots (13)$$

Substituting the series expansion of the exponential integral function into Eq. 12 yields the long-time solution for the dimensionless pressure drop function:

$$p_D(x_D, y_D, t_D) = \frac{1}{2}(\ln t_D + 2.80907) + \sigma(x_D, y_D) \quad \ldots (14)^*$$

where $\sigma(x_D, y_D)$ is a *pseudo skin function* that depends upon the position of the pressure point only:

$$\sigma(x_D, y_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f}$$

$$\cdot \left\{ (x_D - \tfrac{m}{M}) \ln[y_D^2 + (x_D - \tfrac{m}{M})^2] \right.$$

$$-(x_D + \tfrac{m}{M}) \ln[y_D^2 + (x_D + \tfrac{m}{M})^2]$$

$$+ (x_D + \tfrac{m-1}{M}) \ln[y_D^2 + (x_D + \tfrac{m-1}{M})^2]$$

$$-(x_D - \tfrac{m-1}{M}) \ln[y_D^2 + (x_D - \tfrac{m-1}{M})^2]$$

$$- 2y_D \arctan\left[\frac{2y_D}{M}\left(r_D^2 + \frac{m(m-1)}{M^2}\right)\right.$$

$$\left.\left. \div \left([r_D^2 - (\tfrac{m}{M})^2][r_D^2 - (\tfrac{m-1}{M})^2] + \frac{4m(m-1)}{M^2} y_D^2\right)\right]\right\} \quad \ldots (15)$$

where $r_D = r/x_f$ is the dimensionless distance to the axis of the fracture.

Eq. 14 has a form similar to the long-time approximation of the pressure function for radial flow[17] (i.e., a circular well without a fracture):

$$\frac{2\pi kh}{q\mu}(p_i - p_{r,t}) = \frac{1}{2}\left(\ln \frac{kt}{\phi \mu c r^2} + 0.80907\right), \; r \geq r_w \quad \ldots (16)$$

As in the radial flow case, a straight line of slope 1.1515 per logarithmic cycle is obtained when the long-time dimensionless pressure drop is plotted vs the dimensionless flowing time on semilog coordinates. Thus, well test analysis methods developed for transient *radial* flow problems and based upon the existence of the 1.1515 slope semilog straight line, can be extended to analyze transient flow into a vertically fractured well in an infinite system. Actually, it can be shown that Eq. 14 becomes identical with Eq. 16 if x_f

*"2.80907" is correct.

tends to zero, or if r becomes very large.

The q_m's $(m = 1,M)$ in Eq. 15 are obtained by solving the system of equations represented by Eqs. 1 and 2, which now reduces to

$$\begin{cases} \sigma\left(\frac{2j-1}{2M}, 0\right) = \sigma\left(\frac{2j+1}{2M}, 0\right) \\ \qquad j = 1, M-1 \quad \ldots\ldots (17) \\ \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} = M \quad \ldots (18) \end{cases}$$

UNIFORM FLUX VERTICAL FRACTURE

This case corresponds to $M = 1$ and represents a first approximation of the behavior of a vertically fractured well. At early times, however, it is the exact solution.

The corresponding form of Eq. 4 is

$$p_D(x_D, y_D, t_D) = \int_0^{t_D} \exp\left(-\frac{y_D^2}{4t_D'}\right) \cdot \left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t_D'}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t_D'}}\right] \frac{dt_D'}{4(t_D'/\pi)^{1/2}} \quad \ldots\ldots (19)$$

Eq. 19 cannot be expressed in terms of tabulated functions, and must be evaluated with a computer, except in the plane of the fracture ($y_D = 0$), where it becomes

$$p_D(x_D, 0, t_D) = \frac{1}{2}(\pi t_D)^{1/2}\left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t_D}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t_D}}\right] - \frac{(1-x_D)}{4}\operatorname{Ei}\left[-\frac{(1-x_D)^2}{4t_D}\right] - \frac{(1+x_D)}{4}\operatorname{Ei}\left[-\frac{(1+x_D)^2}{4t_D}\right] \quad \ldots\ldots (20)$$

Eq. 20 shows that pressure will vary along the fracture length (except at early times), which would not be true if the fracture had infinite conductivity. However, the pressure drop along the fracture is low, and the uniform flux condition gives the appearance of a high, but not infinite, fracture conductivity. Some field data appear to match this solution better than the infinite-conductivity solution.

One useful expression for well test analysis is the pressure drop on the axis of the fracture ($x_D = 0$, $t_D > 0$):

$$p_{wD}(t_D) = \sqrt{\pi t_D}\ \operatorname{erf}\left(\frac{1}{2\sqrt{t_D}}\right) - \frac{1}{2}\operatorname{Ei}\left(-\frac{1}{4t_D}\right) \quad \ldots\ldots (21)$$

$p_{wD}(t_D)$ has been listed vs t_D in Table 1, and plotted in Figs. 3 and 4 as the $(x_e/x_f = \infty)$ curve.

Approximating forms of Eq. 19 at small and large values of time are the same as obtained in the previous section. The sigma pseudo skin function for the long-time approximation, Eq. 15, simplifies to

$$\sigma(x_D, y_D) = \frac{1}{4}\left\{(x_D-1)\ln[y_D^2 + (x_D-1)^2] - (x_D+1)\ln[y_D^2 + (x_D+1)^2] - 2y_D \arctan\frac{2y_D}{r_D^2 - 1}\right\} \quad \ldots\ldots (22)$$

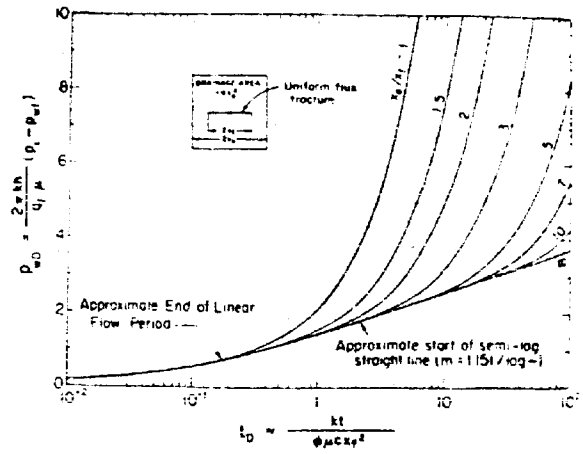

FIG. 3—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

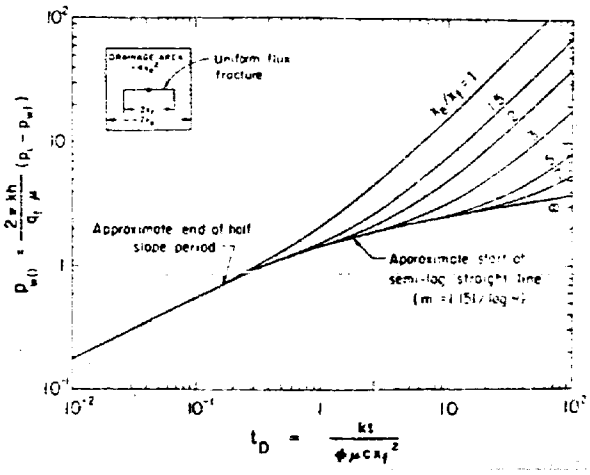

FIG. 4—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

and in the plane of the fracture.

$$\sigma_D(x_D,0) = -\frac{1}{2}\left[(1-x_D)\ln|1-x_D| + (1+x_D)\ln|1+x_D|\right] \quad \ldots (23)$$

TABLE 1 — p_{wD} FOR A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

t_D	Uniform flux	Infinite Conductivity
1.0E-02	0.1772	0.1765
1.5E-02	0.2171	0.2145
2.0E-02	0.2507	0.2456
3.0E-02	0.3070	0.2955
4.0E-02	0.3545	0.3356
5.0E-02	0.3963	0.3697
6.0E-02	0.4340	0.3996
8.0E-02	0.5007	0.4509
1.0E-01	0.5587	0.4945
1.5E-01	0.6790	0.5833
2.0E-01	0.7756	0.6549
3.0E-01	0.9261	0.7691
4.0E-01	1.0417	0.8603
5.0E-01	1.1355	0.9367
6.0E-01	1.2145	1.0027
8.0E-01	1.3427	1.1129
1.0E+00	1.4447	1.2030
1.5E+00	1.6344	1.3754
2.0E+00	1.7716	1.5032
3.0E+00	1.9676	1.6894
4.0E+00	2.1080	1.8248
5.0E+00	2.2175	1.9312
6.0E+00	2.3073	2.0189
8.0E+00	2.4494	2.1583
1.0E+01	2.5600	2.2673
1.5E+01	2.7613	2.4664
2.0E+01	2.9045	2.6085
3.0E+01	3.1065	2.8094
4.0E+01	3.2500	2.9524
5.0E+01	3.3614	3.0634
6.0E+01	3.4524	3.1542
8.0E+01	3.5961	3.2976
1.0E+02	3.7075	3.4089
1.5E+02	3.9101	3.6113
2.0E+02	4.0539	3.7549
3.0E+02	4.2566	3.9575
4.0E+02	4.4004	4.1012
5.0E+02	4.5119	4.2127
6.0E+02	4.6031	4.3039
8.0E+02	4.7469	4.4477
1.0E+03	4.8584	4.5592
1.5E+03	5.0612	4.7619
2.0E+03	5.2050	4.9057
3.0E+03	5.4077	5.1084
4.0E+03	5.5516	5.2523
5.0E+03	5.6631	5.3638
6.0E+03	5.7543	5.4550
8.0E+03	5.8981	5.5988

the long-time approximation applies within 1 percent when

$$t_D > 12.5\left(r_D^2 + \frac{1}{3}\right) \quad \ldots (24)$$

INFINITE-CONDUCTIVITY VERTICAL FRACTURE

The system of linear equations given by Eqs. 17 and 18 must be solved for $2q_m hx_f/q_f$, which represents the ratio of the flux per unit length in the mth segment, q_m, to the flux per unit length in the uniform flux fracture case, $q_f/2hx_f$. The stabilized value of $2q_m hx_f/q_f$ along the half-fracture length is shown in Fig. 5. Although uniform pressure in the fracture can be obtained with as little as 10 segments, it is necessary to use enough divisions to obtain a stabilized value of $\sigma_D(|x_D|<1, 0) = \sigma_{wD}$ in the fracture, as indicated by Fig. 6. The change in σ_{wD} is less than 5×10^{-5} when the number of fracture segments is increased from 59 to 60. In this study, we have used 90 segments to obtain a stabilized value of σ_{wD} in the fracture equal to –0.305. This value of σ_{wD} can be guaranteed to within 0.1 percent. The precision of determination of the dimensionless pressure given by Eq. 14 is, of course, much higher. Eq. 14 then yields for the long-time pressure drop on the fracture,

$$p_{wD}(t_D) = \frac{1}{2}\ln t_D + 1.100 \quad \ldots (25)$$

The same result can be obtained in the uniform flux fracture case by measuring the pressure drop at $x_D = 0.732$ in the fracture. This can be calculated by substituting –0.305 for $\sigma(x_D, 0)$ in Eq. 23. It is obvious in Fig. 7. This suggests that the *pressure drop on the fracture* for the infinite-conductivity fracture can be obtained from that for the *uniform flux fracture*, Eq. 20, with $x_D = 0.732$. The result is

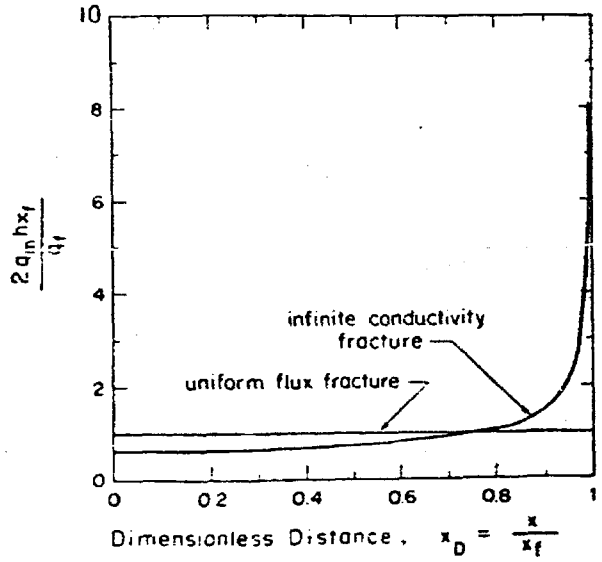

FIG. 5 — STABILIZED FLUX DISTRIBUTION ALONG VERTICAL FRACTURE.

$$p_{wD}(t_D) = \frac{1}{2}\sqrt{\pi t_D}\left[\operatorname{erf}\left(\frac{0.134}{\sqrt{t_D}}\right) + \operatorname{erf}\left(\frac{0.866}{\sqrt{t_D}}\right)\right] - 0.067\,\operatorname{Ei}\left(-\frac{0.018}{t_D}\right) - 0.433\,\operatorname{Ei}\left(-\frac{0.750}{t_D}\right) \quad \ldots\ldots\ldots (26)$$

Eq. 26 yields the correct value of the wellbore pressure for a well with an infinite-conductivity vertical fracture, at early and long times. It can be assumed that it also yields the correct pressure values during the transition period. A similar result ($s_D = 0.78$) has been obtained by Muskat[15] for a well with partial penetration at steady state. $p_{wD}(t_D)$ from Eq. 26 has been listed vs t_D in Table 1, and graphed in Figs. 8 and 9, where it corresponds to the ($x_e/x_f = \infty$) curve.

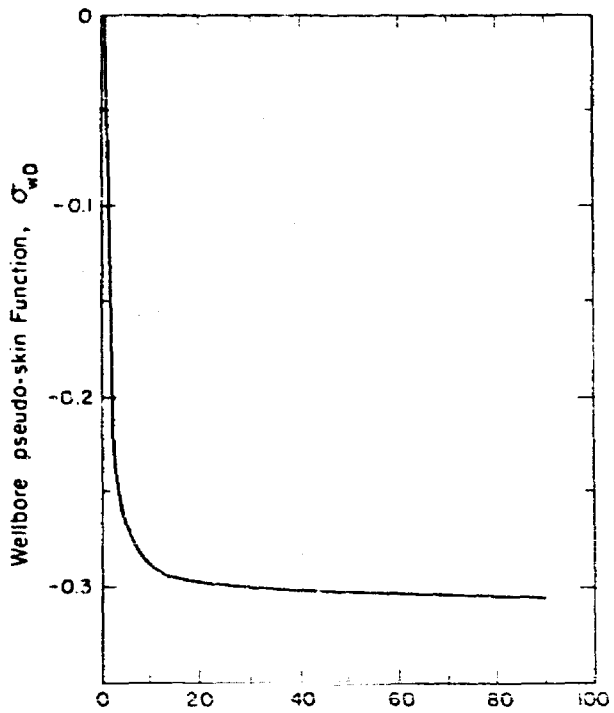

FIG. 6—CONVERGENCE OF THE WELLBORE PSEUDO SKIN FUNCTION σ_{wD} (INFINITE-CONDUCTIVITY FRACTURE).

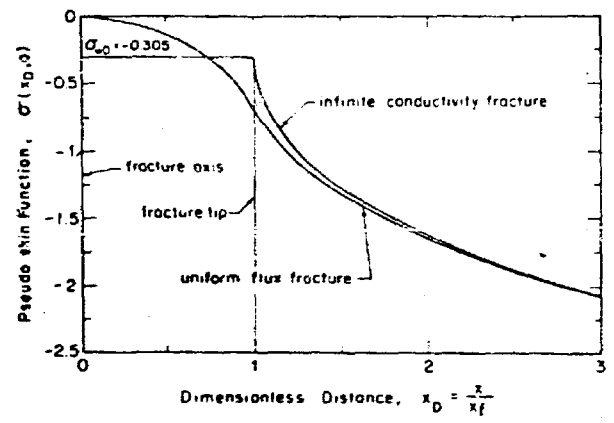

FIG. 7—PSEUDO SKIN FUNCTION VS DIMENSIONLESS DISTANCE.

VERTICALLY FRACTURED WELL IN A RECTANGULAR CLOSED RESERVOIR

When a reservoir is in an early stage of depletion, the production of a particular well is not perturbed by the existence of other wells or by boundary effects. After a while this is no longer true, and a new solution must be developed that considers the reservoir boundaries or the effect of the other wells.

Fig. 10 presents a schematic of a vertically fractured well in a rectangular, closed drainage system. Two types of fracture will be considered — uniform flux and infinite conductivity — but, as in the infinite-reservoir case, it is only necessary to derive the dimensionless pressure drop for the uniform flux fracture. This is obtained immediately

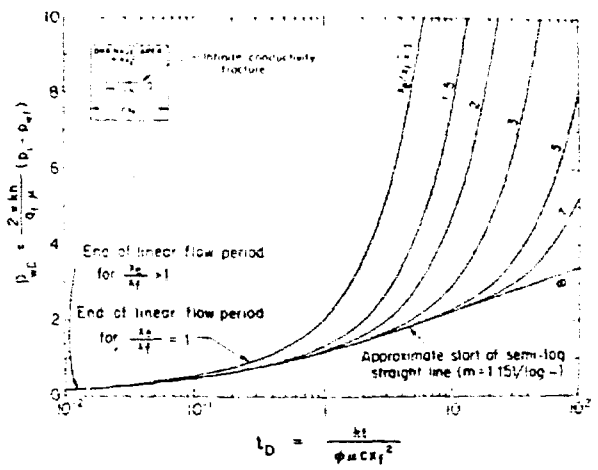

FIG. 8—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

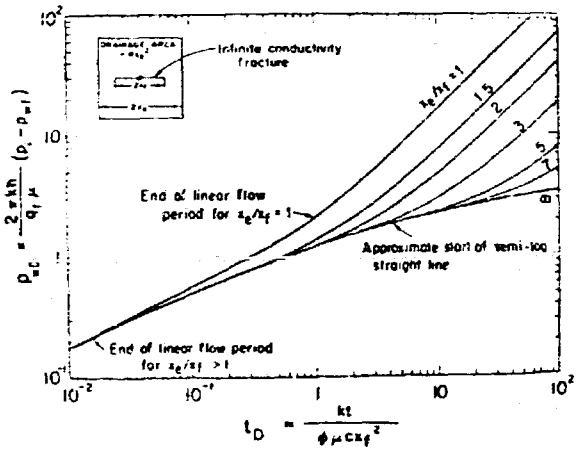

FIG. 9—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

by means of the Green's function and product solution method (see Ref. 14). The result is

$$p_D\left(\frac{x}{x_e}, \frac{y}{y_e}, t_{DA}\right) = 2\pi \int_0^{t_{DA}} \left[1 + 2 \sum_{n=1}^{\infty} \cdot \exp\left(-n^2\pi^2 \frac{x_e}{y_e} t'_{DA}\right) \cos n\pi \frac{y_w}{2y_e} \cdot \cos n\pi \frac{y_w + y}{2y_e}\right] \left[1 + 2 \sum_{n=1}^{\infty} \exp\left(-n^2\pi^2 \cdot \frac{y_e}{x_e} t'_{DA}\right) \frac{\sin n\pi \frac{x_f}{2x_e}}{n\pi \frac{x_f}{2x_e}} \cos n\pi \frac{x_w}{2x_e} \cdot \cos n\pi \frac{x_w + x}{2x_e}\right] dt'_{DA} \quad \ldots\ldots\ldots (27)$$

where t_{DA} represents the dimensionless time based on the drainage area:

$$t_{DA} = \frac{kt}{\phi\mu c 4(x_e\, y_e)^2} \quad \ldots\ldots (28)$$

The pressure drop on the fracture for a vertical fracture at the center of a square ($x_e = y_e$ and $x_w = y_w$) is then given by

$$p_{wD}(t_{DA}) = 2\pi \int_0^{t_{DA}} \left[1 + 2 \sum_{n=1}^{\infty} \exp(-4n^2\pi^2 t'_{DA})\right] \left[1 + 2 \sum_{n=1}^{\infty} \exp(-4n^2\pi^2 t'_{DA}) \frac{\sin n\pi \frac{x_f}{x_e}}{n\pi \frac{x_f}{x_e}} \cdot \cos n\pi\, x_D \frac{x_f}{x_e}\right] dt'_{DA} \quad \ldots\ldots (29)$$

The pressure drops on the fracture for a uniform flux fracture and for an infinite-conductivity fracture are obtained by evaluating Eq. 29 at $x_D = 0$ and $x_D = 0.732$, respectively. The choice of the same point as in the infinite case leads to reasonable results and can be justified *a posteriori* by the method of *superposition*, presented later in this paper. Numerical values of the dimensionless pressure drop from Eq. 29 are listed vs t_{DA} in Tables 2 and 3, and have been plotted vs t_D (not t_{DA}) in Figs. 3 and 4 and Figs. 8 and 9, respectively, for various values of the x_e/x_f ratio. This ratio is used instead of Russell and Truitt's[8] fracture penetration ratio x_f/x_e because the limiting case of a vertical fracture in a square reservoir is a vertical fracture in an infinite reservoir (Figs. 3, 4, 8, and 9), which correspond to $x_e/x_f = \infty$, whereas a zero fracture penetration ratio ($x_f/x_e = 0$) corresponds to an unfractured well in a square reservoir, which is a different problem.

Three different flow periods can be characterized for both types of fractures: a *linear* flow period occurs at early times. This corresponds to the one-half slope straight line in log-log coordinates (Figs. 4 and 9). After a period of transition, there is a *pseudoradial* flow period corresponding to the semilog straight line (Figs. 3 and 8). After a second period of transition, *pseudosteady* state occurs, which is characterized by an approximate unit slope straight line in log-log coordinates. Depending upon x_e/x_f, one or more of these different flow periods may be missing; in the total fracture penetration case ($x_e/x_f = 1$), for instance, the first transition period and the pseudoradial period do not appear, whereas only the pseudoradial period is missing for values of x_e/x_f between 1 and 3 (uniform flux fracture), or 1 and 5 (infinite-conductivity fracture).

DISCUSSION OF VERTICAL FRACTURE SOLUTIONS

A comparison has been made in Table 4, and in Figs. 11 and 12 between the subject analytical solution for the *infinite-conductivity fracture* and Russell and Truitt's results.[8] As can be seen from Figs. 11 and 12, the smaller the x_e/x_f, the closer the two solutions become at long times. The over-all agreement is good, in view of the fact that the Russell and Truitt solution is an explicit finite-difference solution for a very difficult problem. The total fracture penetration cases ($x_e/x_f = 1$) agree exactly at all times. None of the Russell-Truitt curves, however, produce the 1.1515 slope semilog

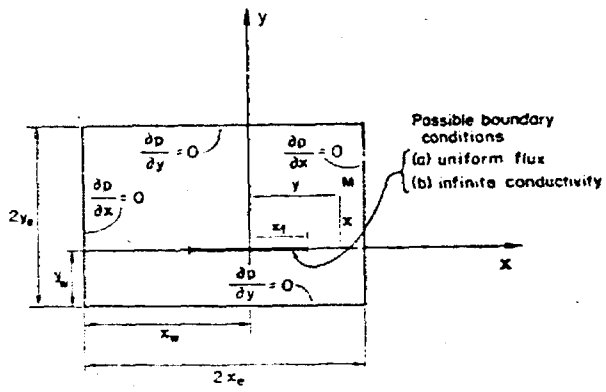

FIG. 10—VERTICAL FRACTURE IN A RECTANGULAR RESERVOIR.

straight line. This result was for many years erroneously thought by one of the authors of this study to be an inherent result of a vertical fracture, rather than an effect caused by the drainage boundaries. Furthermore, at very early times there are some discrepancies in the way the Russell-Truitt curves leave the log-log half-unit slope straight line, which makes them difficult to use with type-curve matching methods. Finally, the difference between the current analytical solution and the Russell-Truitt solution for $x_e/x_f = 10$ is much larger than that for other values of x_e/x_f. This Russell-Truitt case appears to contain an error and is not recommended for further use.

Russell and Truitt did not provide results for a vertically fractured well in an infinite reservoir, but such can be extracted from their results by *superposition*. The behavior of a fractured well in a square is identical with that of an infinite system containing a square array of fractured wells. The square array could be constructed by superposition of single fractured wells in infinite

TABLE 2 — p_{wD} FOR A UNIFORM FLUX VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1772	0.2481	0.3545	0.5306
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2171	0.3039	0.4340	0.6460
2.00E-04	0.0501	0.0752	0.1003	0.1504	0.2507	0.3509	0.5007	0.7392
3.00E-04	0.0614	0.0921	0.1228	0.1842	0.3070	0.4297	0.6105	0.8855
4.00E-04	0.0709	0.1063	0.1418	0.2127	0.3545	0.4957	0.6999	0.9986
5.00E-04	0.0793	0.1189	0.1585	0.2378	0.3962	0.5533	0.7756	1.0908
6.00E-04	0.0868	0.1302	0.1737	0.2605	0.4340	0.6046	0.8414	1.1686
8.00E-04	0.1003	0.1504	0.2005	0.3008	0.5007	0.6933	0.9515	1.2953
1.00E-03	0.1121	0.1681	0.2242	0.3363	0.5587	0.7686	1.0417	1.3963
1.50E-03	0.1373	0.2059	0.2746	0.4118	0.6790	0.9183	1.2145	1.5846
2.00E-03	0.1585	0.2378	0.3171	0.4752	0.7756	1.0334	1.3427	1.7211
3.00E-03	0.1942	0.2912	0.3883	0.5801	0.9261	1.2057	1.5294	1.9164
4.00E-03	0.2242	0.3363	0.4482	0.6661	1.0417	1.3336	1.6650	209565
5.00E-03	0.2507	0.3760	0.5007	0.7392	1.1355	1.4354	1.7716	2.1658
6.00E-03	0.2746	0.4118	0.5477	0.8030	1.2145	1.5199	1.8594	2.2554
8.00E-03	0.3171	0.4752	0.6297	0.9103	1.3427	1.6554	1.9990	2.3973
1.00E-02	0.3545	0.5306	0.6999	0.9986	1.4447	1.7619	2.1080	2.5078
1.50E-02	0.4342	0.6460	0.8414	1.1686	1.6344	1.9577	2.3073	2.7090
2.00E-02	0.5013	0.7393	0.9515	1.2953	1.7716	2.0981	2.4495	2.8520
3.00E-02	0.6140	0.8861	1.1183	1.4804	1.9676	2.2974	2.6505	3.0541
4.00E-02	0.7092	1.0011	1.2443	1.6159	2.1086	2.4400	2.7940	3.1980
5.00E-02	0.7935	1.0973	1.3470	1.7241	2.2201	2.5524	2.9069	3.3111
6.00E-02	0.8708	1.1819	1.4356	1.8161	2.3140	2.6469	3.0016	3.4061
8.00E-02	1.0127	1.3315	1.5893	1.9734	2.4732	2.8067	3.1618	3.5664
1.00E-01	1.1458	1.4678	1.7273	2.1129	2.6136	2.9473	3.3025	3.7072
1.50E-01	1.4652	1.7895	2.0502	2.4368	2.9381	3.2720	3.6273	4.0320
2.00E-01	1.7801	2.1047	2.3655	2.7523	3.2537	3.5876	3.9429	4.4477
3.00E-01	2.4086	2.7332	2.9941	3.3808	3.8823	4.2162	4.5715	4.9762
4.00E-01	3.0369	3.3615	3.6224	4.0092	4.5106	4.8445	5.1998	5.6045
5.00E-01	3.6652	3.9898	4.2507	4.6375	5.1389	5.4728	5.8281	6.2328
6.00E-01	4.2935	4.6181	4.8790	5.2658	5.7672	6.1011	6.4564	6.8512
8.00E-01	5.5501	5.8748	6.1357	6.5224	7.0239	7.3578	7.7131	8.1178
1.00E+00	6.8068	7.1314	7.3923	7.7791	8.2805	8.6144	8.9697	9.3744
1.50E+00	9.9484	10.2730	10.5339	10.9207	11.4221	11.7560	12.1113	12.5160
2.00E+00	13.0900	13.4146	13.6755	14.0623	14.5637	14.8976	15.2529	15.6576
3.00E+00	19.3732	19.6978	19.9587	20.3455	20.8469	21.1808	21.5361	21.9408
4.00E+00	25.6563	25.9810	26.2418	26.6286	27.1301	27.4639	27.8193	28.2240
5.00E+00	31.9395	32.3641	32.5250	32.9118	33.4132	33.7471	34.1024	34.5072
6.00E+00	38.2227	38.5473	38.8082	39.1950	39.6964	40.0303	40.3856	40.7904
8.00E+00	50.7891	51.1137	51.3746	51.7614	52.2628	52.5967	52.9520	53.3567

mediums in the same way a well in a closed square was constructed by Matthews *et al.*[18] and by Earlougher *et al.*[19] We realize that the pressure drop at a great distance from a fractured well produced at constant rate is essentially identical with the pressure drop caused by an unfractured well. Thus, the behavior of a fractured well in a closed square may be approximated by generating the drainage boundaries with unfractured wells, if x_e, y_e is large enough. This simple approach can also be used to extract the behavior of a fractured well in an infinite medium from that of a fractured well in a closed square. This can be stated as follows: the p_D for a fractured well in an infinite medium is equal to the p_D for a fractured well in a closed square, less the p_D for an unfractured well in a closed square, plus the p_D for an unfractured well in an infinite medium. The method has been applied to both the current analytical solutions and Russell-Truitt solutions for an infinite-conductivity fracture in a closed square reservoir (Table 4 and Fig. 13). The data for an unfractured well in a

TABLE 3 — p_{wD} FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1765	0.2433	0.3356	0.4735
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2145	0.2928	0.3996	0.5590
2.00E-04	0.0501	0.0752	0.1003	0.1502	0.2456	0.3327	0.4509	0.6278
3.00E-04	0.0614	0.0921	0.1228	0.1832	0.2955	0.3962	0.5328	0.7379
4.00E-04	0.0709	0.1062	0.1417	0.2104	0.3356	0.4471	0.5987	0.8259
5.00E-04	0.0793	0.1139	0.1582	0.2338	0.3697	0.4904	0.6549	0.9000
6.00E-04	0.0868	0.1302	0.1730	0.2545	0.3996	0.5284	0.7042	0.9642
8.00E-04	0.1003	0.1502	0.1989	0.2901	0.4509	0.5939	0.7889	1.0718
1.00E-03	0.1121	0.1676	0.2212	0.3204	0.4945	0.6496	0.8603	1.1600
1.50E-03	0.1373	0.2040	0.2671	0.3821	0.5833	0.7631	1.0027	1.3296
2.00E-03	0.1585	0.2338	0.3041	0.4315	0.6549	0.8536	1.1129	1.4560
3.00E-03	0.1942	0.2818	0.3633	0.5104	0.7691	0.9953	1.2792	1.6405
4.00E-03	0.2242	0.3204	0.4107	0.5738	0.8603	1.1050	1.4037	1.7750
5.00E-03	0.2507	0.3533	0.4509	0.6278	0.9367	1.1947	1.5033	1.8808
6.00E-03	0.2746	0.3821	0.4863	0.6753	1.0027	1.2707	1.5862	1.9681
8.00E-03	0.3171	0.4315	0.5470	0.7569	1.1129	1.3948	1.7196	2.1071
1.00E-02	0.3545	0.4735	0.5987	0.8259	1.2030	1.4941	1.8248	2.2158
1.50E-02	0.4342	0.5595	0.7043	0.9642	1.3754	1.6800	2.0189	2.4146
2.00E-02	0.5013	0.6295	0.7891	1.0718	1.5033	1.8152	2.1583	2.5564
3.00E-02	0.6140	0.7445	0.9239	1.2352	1.6896	2.0092	2.3567	2.7572
4.00E-02	0.7092	0.8406	1.0316	1.3592	1.8256	2.1492	2.4989	2.9006
5.00E-02	0.7935	0.9254	1.1235	1.4607	1.9342	2.2600	2.6110	3.0133
6.00E-02	0.8708	1.0030	1.2054	1.5486	2.0264	2.3536	2.7053	3.1081
8.00E-02	1.0127	1.1452	1.3521	1.7015	2.1838	2.5124	2.8649	3.2682
1.00E-01	1.1458	1.2784	1.4872	1.8392	2.3234	2.6527	3.0055	3.4089
1.50E-01	1.4652	1.5979	1.8081	2.1619	2.6474	2.9771	3.3301	3.7337
2.00E-01	1.7801	1.9128	2.1231	2.4772	2.9629	3.2926	3.6457	4.0493
3.00E-01	2.4086	2.5413	2.7516	3.1057	3.5915	3.9212	4.2743	4.6778
4.00E-01	3.0369	3.1696	3.3799	3.7341	4.2198	4.5495	4.9026	5.3061
5.00E-01	3.6652	3.7979	4.0082	4.3624	4.8481	5.1778	5.5309	5.9345
6.00E-01	4.2935	4.4262	4.6366	4.9907	5.4764	5.8061	6.1592	6.5628
8.00E-01	5.5501	5.6829	5.8932	6.2473	6.7331	7.0628	7.4159	7.8194
1.00E+00	6.8068	6.9395	7.1498	7.5040	7.9897	8.3194	8.6725	9.0761
1.50E+00	9.9484	10.0811	10.2914	10.6456	11.1313	11.4610	11.8141	12.2177
2.00E+00	13.0900	13.2227	13.4330	13.7872	14.2729	14.6026	14.9557	15.3592
3.00E+00	19.3732	19.5059	19.7162	20.0703	20.5561	20.8858	21.2389	21.6424
4.00E+00	25.6563	25.7891	25.9994	26.3535	26.8393	27.1690	27.5220	27.9256
5.00E+00	31.9395	32.0722	32.2826	32.6367	33.1224	33.4521	33.8052	34.2088
6.00E+00	38.2227	38.3554	38.5658	38.9199	39.4056	39.7353	40.0884	40.4920
8.00E+00	50.7891	50.9218	51.1321	51.4863	51.9720	52.3017	52.6548	53.0584

closed square were taken from Table 1, Ref. 19. It was found that desuperposition of the analytical solution for a closed square yields a very good approximation of the analytical solution for an infinite reservoir, for x_e/x_f values of 2, 5, and 10/3. This justifies *a posteriori* the choice of $s_D = 0.732$ for representing the wellbore pressure for an infinite-conductivity fracture in the finite-reservoir case. x_e/x_f ratios of 10/7 and 1 gives p_D values that are much too large, implying that desuperposition cannot be used because the fracture is too close to the square boundary. The $x_e/x_f = 10$ case yields p_D values by desuperposition that are far too small. It is likely that the Russell and Truitt results have a small, almost constant error for this case. It should be noted, however, that the Russell and Truitt desuperposed solution for an infinite reservoir does have a slope of 1.151 when plotted on semilog coordinates, although their solutions for the closed square did not.

An interesting interpretation of the behavior of a vertically fractured well can be made in terms of an equivalent unfractured system. Prats[5] has shown that an infinite-conductivity vertical fracture, producing an incompressible fluid from a closed circular reservoir *at steady state*, is equivalent to an unfractured well with an effective radius equal to a quarter of the total fracture length, for ratios of the reservoir radius to the fracture half length greater than 2. The same is true, within 7 percent,

TABLE 4 — COMPARISON BETWEEN ANALYTICAL AND FINITE-DIFFERENCE WELLBORE PRESSURES FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A CLOSED SQUARE

t_{DA} / x_e/x_f=1	1		10/7		2	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.0 E-04	0.0354	0.0355	0.0506	0.0506	0.0709	0.0709
2.0 E-04	0.0501	0.0501	0.0716	0.0716	0.1003	0.1003
5.0 E-04	0.0793	0.0793	0.1132	0.1107	0.1582	0.1527
8.0 E-04	0.1003		0.1431		0.1989	
1.0 E-03	0.1121	0.1121	0.1598	0.1528	0.2212	0.2092
2.0 E-03	0.1585	0.1585	0.2233	0.2111	0.3082	0.2870
5.0 E-03	0.2507	0.2507	0.3386	0.3220	0.4509	0.4326
8.0 E-03	0.3171	0.3171	0.4142	0.3982	0.5470	0.5306
1.0 E-02	0.3545	0.3545	0.4548	0.4398	0.5987	0.5836
2.0 E-02	0.5013	0.5014	0.6062	0.5969	0.7891	0.7755
5.0 E-02	0.7935	0.7936	0.8973	0.8947	1.1235	1.1051
8.0 E-02	1.0127	1.0127	1.1160	1.1145	1.3521	1.3309
1.0 E-01	1.1458	1.1457	1.2489	1.2477	1.4872	1.4654
2.0 E-01	1.7801	1.7797	1.8832	1.8818	2.1231	2.1003
5.0 E-01	3.6652	3.6648	3.7683	3.7668	4.0082	3.9853
8.0 E-01	5.5501	5.5498	5.6532	5.6517	5.8932	5.8702
1.0 E+00	6.8068	6.8064	6.9099	6.9034	7.1498	7.1269
2.0 E+00	13.0900	13.0696	13.1930	13.1916	13.4330	13.4101
5.0 E+00	31.9395		32.0426		32.2826	
8.0 E+00	50.7891		50.8922		51.1321	

t_{DA} / x_e/x_f=1	10/3		5		10	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.0 E-04	0.1181	0.1182	0.1765	0.1772	0.3356	0.3545
2.0 E-04	0.1666	0.1671	0.2456	0.2476	0.4509	0.4715
5.0 E-04	0.2578	0.2483	0.3697	0.3575	0.6549	0.6395
8.0 E-04	0.3187		0.4509		0.7889	
1.0 E-03	0.3514	0.3318	0.4945	0.4780	0.8603	0.8013
2.0 E-03	0.4711	0.4480	0.6549	0.6390	1.1129	1.0171
5.0 E-03	0.6830	0.6586	0.9367	0.9164	1.5033	1.3697
8.0 E-03	0.8220	0.7951	1.1129	1.0872	1.7196	1.5732
1.0 E-02	0.8958	0.8668	1.2030	1.1742	1.8248	1.6735
2.0 E-02	1.1550	1.1167	1.5033	1.4659	2.1583	1.9970
5.0 E-02	1.5552	1.5045	1.9342	1.8894	2.6110	2.4430
8.0 E-02	1.7984	1.7442	2.1838	2.1372	2.8649	2.6958
1.0 E-01	1.9366	1.8817	2.3234	2.2766	3.0055	2.8361
2.0 E-01	2.5751	2.5189	2.9629	2.9154	3.6457	3.4757
5.0 E-01	4.4602	4.4039	4.8481	4.8004	5.5309	5.3607
8.0 E-01	6.3452	6.2889	6.7331	6.6853	7.4159	7.2456
1.0 E+00	7.6018	7.5455	7.9897	7.9419	8.6725	8.5023
2.0 E+00	13.8850	13.8287	14.2729	14.2252	14.9557	14.7855
5.0 E+00	32.7345		33.1224		33.8052	
8.0 E+00	51.5841		51.9720		52.6548	

for a compressible fluid at *steady* or *pseudosteady* state.[6] We can see that these results apply to a vertically fractured well in an infinite reservoir during the *pseudoradial* period, because Eq. 25 can be written as

$$p_{wD}(t_D) = \frac{1}{2}\left[\ln\left(\frac{kt}{\phi\mu c\left(\frac{x_f}{2}\right)^2}\right) + 0.80907\right] \quad \ldots\ldots\ldots \quad (30)$$

The effective well radius for an infinite-conductivity vertical fracture in an infinite reservoir is thus exactly one-fourth the total fracture length. The effective radius for an infinite-conductivity vertical fracture in a closed square reservoir at *pseudosteady state* may be obtained from the general pseudosteady-state depletion equation presented by Brons and Miller,[20] which, in the present case, can be expressed as

$$p_{wD} = 2\pi\, t_{DA} + \ln\frac{4(x_f/r'_w)}{\sqrt{e^{\gamma}C_A}}\,\frac{x_e}{x_f}, \quad \ldots \quad (31)$$

where C_A is the shape factor for a well in a square, and r'_w is the effective well radius. Effective radii computed from the current analytical solution and from the Russell and Truitt solution are compared in Fig. 14 with the results of Prats *et al.*[6] for various values of x_f/x_e (x_f/x_e is used for convenience in this case). Surprisingly, variations of the radii as a function of x_f/x_e are different in the Prats *et al.* results. Again, the result for $x_f/x_e = 0.1$ in Russell-Truitt's case is inconsistent with other results.

Comparison was also made between the subject solution and the analytical results of van Everdingen and Meyer[11] for an infinite-conductivity fracture in an infinite reservoir. Although not shown, results do not compare well. The van Everdingen and Meyer solution is correct during the initial linear flow period. But it yields a semilog straight line of slope 0.576 per $\log_{10}$ cycle, instead of 1.151 per $\log_{10}$ cycle as in the subject study, or as in the Russell and Truitt[8] desuperposed solution. It is not recommended that this solution be used in the pseudoradial flow period. Either the current analytical solution, or the desuperposed Russell-Truitt solution for a fractured well in an infinite medium may be used.

NOMENCLATURE

C_A = pseudosteady-state shape factor for a well at the center of a square[19] = 30.86

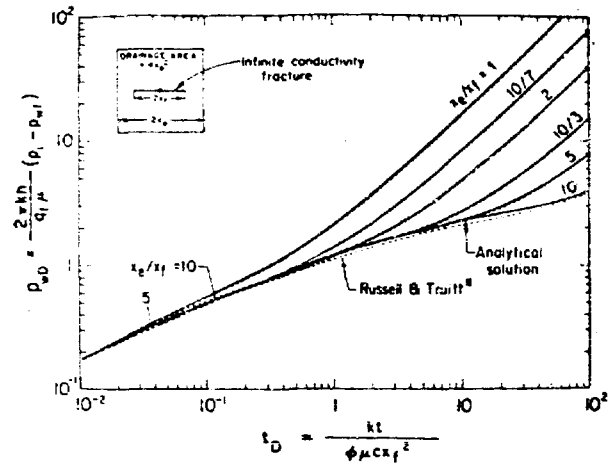

FIG. 12 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A CLOSED SQUARE.

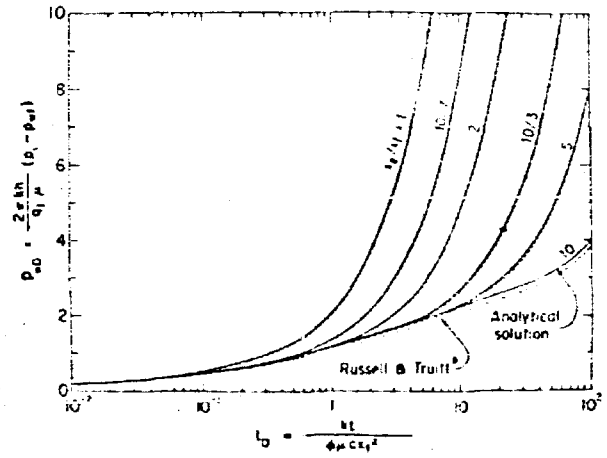

FIG. 11 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A SQUARE.

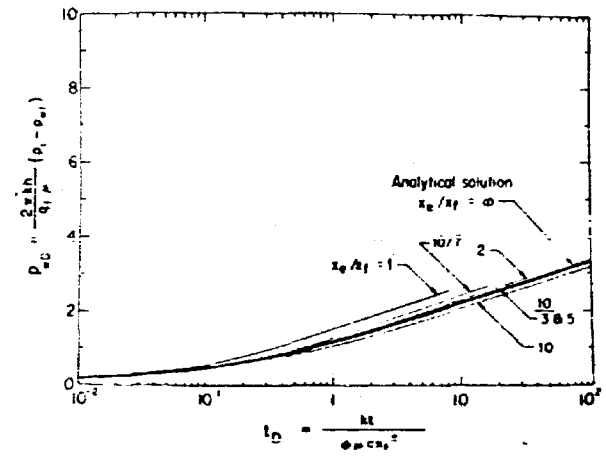

FIG. 13 — DESUPERPOSITION OF RUSSELL AND TRUITT RESULTS TO OBTAIN A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR AND COMPARISON WITH THE SUBJECT ANALYTICAL SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

h = formation thickness
k = formation permeability
M = number of vertical fracture elements for generating an infinite-conductivity fracture
p = pressure
p_i = initial reservoir pressure
p_D = dimensionless pressure
q_f = total withdrawal rate from fracture
q_m = flux per unit area in vertical fracture elements
r = distance to fracture axis
r_D = dimensionless distance to fracture axis, based on fracture half length
r'_w = effective well radius
t = flowing time
t_D = dimensionless time based on the fracture half length
t'_D = dummy variable of integration
t_{DA} = dimensionless time based on drainage area
x,y = space coordinates
x_D, y_D = dimensionless coordinates based on the fracture half length
x_e, y_e = rectangular reservoir half dimensions
x_f = fracture half length
x_w, y_w = fracture axis coordinates
γ = Euler's constant = 0.5772
η = diffusivity constant
μ = fluid viscosity

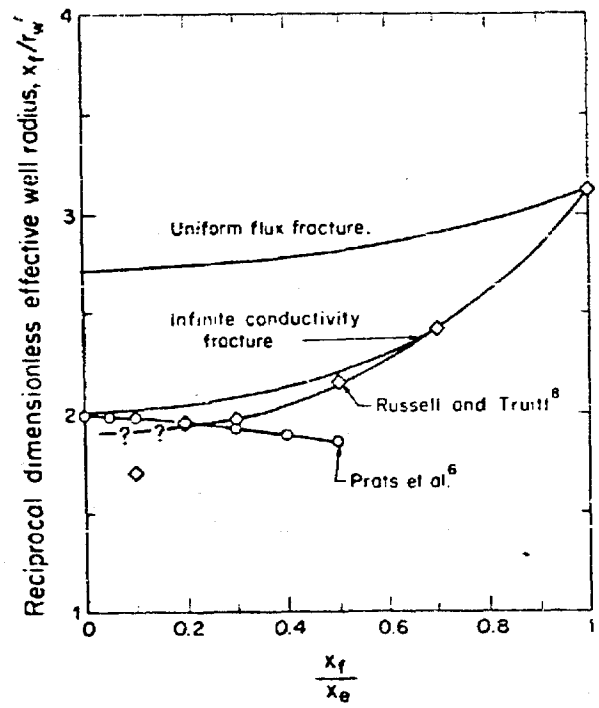

FIG. 14—COMPARISON OF RECIPROCAL DIMENSIONLESS EFFECTIVE WELL RADIUS, x_f/r'_w.

s = pseudo skin function, defined by Eq. 14
τ = dummy variable of integration
ϕ = formation porosity

SPECIAL FUNCTIONS

Inverse tangent function:

$$\arctan(x) = \tan^{-1}(x)$$

Exponential integral:

$$-Ei(-x) = \int_0^x \frac{e^{-u}}{u}\,du$$

Error function:

$$erf(x) = \frac{2}{\sqrt{\pi}} \int_0^x e^{-u^2}\,du$$

Complementary error function:

$$erfc(x) = 1 - erf(x)$$

Units: CGS units are used throughout this study.

ACKNOWLEDGMENTS

We acknowledge the financial assistance of the Miller Institute for Basic Research in Science, U. of California at Berkeley. We are also thankful to Texaco and the Mobil Foundation for financial aid. Computer time was contributed by the Computer Center of the U. of California and by Stanford U.

In addition, helpful correspondence has been conducted with a number of persons. Conversations with A. F. van Everdingen and L. Joffre Meyer formed part of the inspiration for this study. We are deeply grateful to R. A. Morse and W. D. von Gonten of Texas A&M U. for finite-difference-solution results, which aided in establishing correct vertical-fracture solutions. Finally, helpful comments were also received from D. G. Russell of Shell Development Co.

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REVISED EXHIBIT NO. 13

Revised Exhibit No. 13 presents assumptions and economic calculations for additional drilling in the Rattlesnake Canyon Tight Formation Area. These projections are based on average producing and projected rates for wells located in Sections 25, 26, 27 and 35, Township 32 North Range 9 West, and in Section 31, Township 32 North Range 8 West. These reserves represent the maximum average reserves Koch could expect from additional drilling on their portion of the tight formation area. The average reserves of 493625 MCF per well under existing pricing is more than expected from Koch's recent wells north of Sections 35 and 36.

Reserves presented in Exhibit No. 6 are those expected under existing pricing. Tight formation pricing would result in a new economic limit and increase the ultimate average reserves from 493,625 MCF per well to 516,333 MCF per well.

The typical well will produce approximately 63 MMCF during the first full year of production followed by a year with an annual decline rate of 37 percent. The average decline expected after the second year through the seventh year is 10 percent. After the seventh year the wells are expected to slowly decline at approximately five percent per year to their economic limit.

The economic calculations presented do not include the risk of mechanical problems while drilling and completing, or the problems which may occur over the long life of the wells. It is doubtful that many of the wells can be operated trouble free for the projected life of 44 years. The rate of return calculations are based on the wells being connected immediately after completion. A delay of as much as six months between completion and initial sales is not uncommon in this area.

The summary of economics shows that the expected rate of return of new wells, based on Section 103 gas prices is approximately 9 percent before federal income tax and is reduced to approximately 7 percent after federal income tax. These low rates of return are accompanied by a payout in excess of 8 years. Koch's minimum economic requirements are normally a 15 percent rate of return after federal income tax with no escalation applied for inflation. However, with the current high interest rates, the requirements will probably increase in the near future.

Tight formation gas prices will result in an after federal income tax rate of return of 27 percent with a payout of approximately three years. While these are not excessive, they will permit additional development in the area.

Copies of the computer printout for each of the four cases run are included with Exhibit No. 13.

EXHIBIT NO. 13

REVISED

ASSUMPTIONS AND RESULTS OF ECONOMIC CALCULATIONS

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

ASSUMPTIONS

Drilling and Completion Costs, $	400,700
Expense Interest, %	100
Royalty Interest, %	15
Yield, Bbl/MMCF	0
Sec. 103 Gas Price, $/MMCF	2.389
Tight Fm Gas Price, $/MMCF	4.778
Operating Costs, $/well/yr	4800
Severance and Ad Val Tax, %	8
Income Tax Rate, %	48.7

RESULTS

	Sec. 103 Price	Tight Fm Price
Ultimate Reserves, MMCF	494	516
Before Fed. Income Tax Economics		
Discounted Cash Flow Rate of Return, %	8.8	39.2
Payout, Yrs	8.4	2.3
Cash Flow, M $	314	1264
% Discounted Cash Flow, M $	-88	258
After Fed. Income Tax Economics		
Discounted Cash Flow Rate of Return, %	7.3	28
Payout, Yrs	9.5	2.9
Cash Flow, M $	171	658
15% Discounted Cash Flow, M $	-76	101

:RATTLESNAKE CANYON
:BLANCO MESAVERDE PLD
SAN JUAN CO NEW MEXICO
SEC 103 PRICE

DATE: 09/28/81
TIME: 17:56CDT
FILE: RATTLE
PROJ: 0

A F T E R T A X E C O N O M I C S

NOOH EXPLORATION, INC
:EXHIBIT NO 13

AS OF DATE: 1/ 1/1981

-END- MO-YR	GROSS OIL MB	GROSS GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	63.290	218.238	4.800	113.438	400.700	12.411	0.	-108.478	-178.784	-193.538
12-82	0.	36.690	68.544	4.800	63.744	0.	7.195	0.	27.539	36.205	-164.156
12-83	0.	27.468	51.316	4.800	46.516	0.	5.387	0.	20.030	26.486	-145.465
12-84	0.	24.727	46.195	4.800	41.395	0.	4.849	0.	17.798	23.597	-130.985
12-85	0.	22.265	41.595	4.800	36.795	0.	4.366	0.	15.793	21.002	-119.778
12-86	0.	20.051	37.460	4.800	32.660	0.	3.932	0.	13.990	18.670	-111.115
12-87	0.	18.062	33.743	4.800	28.943	0.	3.542	0.	12.370	16.573	-104.428
12-88	0.	16.697	31.193	4.800	26.393	0.	3.274	0.	11.259	15.134	-99.118
12-89	0.	15.850	29.611	4.800	24.811	0.	3.108	0.	10.569	14.242	-94.773
12-90	0.	15.046	28.109	4.800	23.309	0.	2.951	0.	9.915	13.394	-91.220
12-91	0.	14.284	26.686	4.800	21.886	0.	2.801	0.	9.294	12.592	-88.315
12-92	0.	13.562	25.336	4.800	20.536	0.	2.659	0.	8.706	11.830	-85.942
12-93	0.	12.876	24.055	4.800	19.255	0.	2.525	0.	8.148	11.107	-84.005
12-94	0.	12.226	22.841	4.800	18.041	0.	2.398	0.	7.618	10.423	-82.424
12-95	0.	11.609	21.687	4.800	16.887	0.	2.276	0.	7.115	9.772	-81.135
:S TOT	0.	324.703	606.609	72.000	534.609	400.700	63.674	0.	71.666	62.243	-81.135
:AFTER	0.	168.922	315.580	135.966	179.614	0.	33.126	0.	71.339	108.275	-75.631
TOTAL	0.	493.625	922.189	207.966	714.223	400.700	96.800	0.	143.005	170.518	-75.631

:RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	0.849999
OIL RESERVES,MB	0.	0.	0.
GAS RESERVES,MMCF	493.625	493.625	419.581
PRODUCTS	0.	0.	0.
REVENUE,M$	1179.270	1179.270	922.189
OPERATING EXPENSE,M$	207.966	207.966	207.966
TANGIBLES,M$	96.800	96.800	96.800
INTANGIBLES,M$	303.900	303.900	303.900
INITIAL OIL PRICE ($/B)		0.	
INITIAL GAS PRICE ($/M)		2.3890	

LIFE,(YEARS)	43.33
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	7.29
DISCOUNT RATE,PCT	15.0
PAYOUT YEARS	9.51
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	NET P.W. M$
5	30.746
10	-36.304
15	-75.632
20	-101.964
30	-136.114
40	-158.221
50	-174.253
70	-196.772
100	-218.666

RATTLESNAKE CANYON
BLANCO MESAVERDE FLD
SAN JUAN CO NEW MEXICO
SEC 103 PRICE
NOCH EXPLORATION, INC
EXHIBIT NO 13

DATE: 09/28/81
TIME: 17:53CDT
FILE: RATTLE
PROJ: 0

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -MB-	GROSS GAS PRODUCTION -MMF-	OIL TO NET INTEREST -MB-	GAS TO NET INTEREST -MMF-	REVENUE TO INTEREST -M$-	NET INVESTMENT -M$-	NET OPER EXPENSES -M$-	NET INCOME BEFORE FIT -M$-	CUMULATIVE NET INCOME -M$-	15.000 PCT CUM. DISC NET INCOME -M$-
12-81	0.	63.290	0.	53.797	118.238	400.700	4.800	-287.262	-287.262	-294.776
12-82	0.	36.690	0.	31.186	68.544	0.	4.800	63.744	-223.518	-243.046
12-83	0.	27.468	0.	23.348	51.316	0.	4.800	46.516	-177.002	-210.221
12-84	0.	24.727	0.	21.018	46.195	0.	4.800	41.395	-135.607	-184.819
12-85	0.	22.265	0.	18.925	41.595	0.	4.800	36.795	-98.812	-165.185
12-86	0.	20.051	0.	17.043	37.460	0.	4.800	32.660	-66.152	-150.031
12-87	0.	18.062	0.	15.353	33.743	0.	4.800	28.943	-37.209	-138.353
12-88	0.	16.697	0.	14.192	31.193	0.	4.800	26.393	-10.816	-129.093
12-89	0.	15.850	0.	13.473	29.611	0.	4.800	24.811	13.995	-121.524
12-90	0.	15.046	0.	12.789	28.109	0.	4.800	23.309	37.304	-115.340
12-91	0.	14.284	0.	12.141	26.686	0.	4.800	21.886	59.190	-110.291
12-92	0.	13.562	0.	11.528	25.336	0.	4.800	20.536	79.726	-106.172
12-93	0.	12.876	0.	10.945	24.055	0.	4.800	19.255	98.981	-102.813
12-94	0.	12.226	0.	10.392	22.841	0.	4.800	18.041	117.022	-100.077
12-95	0.	11.609	0.	9.868	21.687	0.	4.800	16.887	133.909	-97.849
E TOT	0.	324.703	0.	275.998	606.609	400.700	72.000	133.909	133.909	-97.849
AFTER	0.	168.922	0.	143.583	315.580	0.	135.966	179.614	313.523	-88.479
TOTAL	0.	493.625	0.	419.581	922.189	400.700	207.966	313.523	313.523	-88.479

CUM.	0.	0.	NET OIL REVENUE	0.	5 PCT	83.350	40 PCT -209.608
			NET GAS REVENUE	922.189	10 PCT	-25.910	50 PCT -230.269
ULT.	0.	493.625	NET PROD REVENUE	0.	15 PCT	-88.479	60 PCT -245.415
					20 PCT	-129.096	80 PCT -266.408
CUM NET INC/INV(1)		0.782	CUM NET PW/INV(1)	-0.221	30 PCT	-179.267	100 PCT -280.480
GROSS WELLS		1	LIFE (YEARS)	43.33			
MONTH IN 1ST YEAR		12	RATE OF RETURN,PCT	8.81			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	85.0000			

RATTLESNAKE CANYON
BLANCO MESAVERDE FLD
SAN JUAN CO NEW MEXICO
TIGHT FM PRICE

DATE: 09/28/81
TIME: 17:43CDT
FILE: RATTLE
PROJ: 0

A F T E R T A X E C O N O M I C S

NOOH EXPLORATION, INC
EXHIBIT NO 13

AS OF DATE: 1/ 1/1981

--END-INC-YR	GROSS OIL MB-----	GROSS GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	63.290	236.477	4.800	231.677	400.700	11.865	0.	-50.630	-118.393	-137.177
12-82	0.	36.690	137.088	4.800	132.288	0.	6.878	0.	61.074	71.214	-79.384
12-83	0.	27.468	102.631	4.800	97.831	0.	5.150	0.	45.136	52.695	-42.198
12-84	0.	24.727	92.390	4.800	87.590	0.	4.636	0.	40.399	47.191	-13.240
12-85	0.	22.265	83.191	4.800	78.391	0.	4.174	0.	36.144	42.247	9.303
12-86	0.	20.051	74.918	4.800	70.118	0.	3.759	0.	32.317	37.801	26.843
12-87	0.	18.062	67.487	4.800	62.687	0.	3.386	0.	28.879	33.808	40.484
12-88	0.	16.697	62.387	4.800	57.587	0.	3.130	0.	26.520	31.067	51.384
12-89	0.	15.850	59.222	4.800	54.422	0.	2.971	0.	25.056	29.366	60.343
12-90	0.	15.046	56.217	4.800	51.417	0.	2.821	0.	23.666	27.751	67.705
12-91	0.	14.284	53.371	4.800	48.571	0.	2.678	0.	22.350	26.221	73.754
12-92	0.	13.562	50.673	4.800	45.873	0.	2.543	0.	21.102	24.771	78.723
12-93	0.	12.876	48.110	4.800	43.310	0.	2.414	0.	19.916	23.394	82.804
12-94	0.	12.226	45.681	4.800	40.881	0.	2.292	0.	18.793	22.088	86.154
12-95	0.	11.609	43.376	4.800	38.576	0.	2.176	0.	17.727	20.849	88.904
S TOT	0.	324.703	1213.219	72.000	1141.219	400.700	60.874	0.	368.449	372.070	88.904
AFTER	0.	191.632	716.015	193.155	522.858	0.	35.926	0.	237.136	285.722	101.291
TOTAL	0.	516.335	1929.232	265.155	1664.077	400.700	96.800	0.	605.585	657.792	101.291

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	0.850000
OIL RESERVES,MB	0.	0.	0.
GAS RESERVES,MMCF	516.335	516.335	438.885
PRODUCTS	0.	0.	0.
REVENUE,M$	2467.049	2467.049	1929.232
OPERATING EXPENSE,M$	265.155	265.155	265.155
TANGIBLES,M$	96.800	96.800	96.800
INTANGIBLES,M$	303.900	303.900	303.900
INITIAL OIL PRICE ($/B)	0.		
INITIAL GAS PRICE ($/M)	4.7780		

LIFE,(YEARS)	55.24
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	27.51
DISCOUNT RATE,PCT	15.0
PAYOUT YEARS	2.90
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	NET P.W. M$
5	323.358
10	180.453
15	101.290
20	50.155
30	-13.727
40	-53.403
50	-81.242
70	-118.908
100	-153.868

RATTLESNAKE CANYON
BLANCO MESAVERDE FLD
SAN JUAN CO NEW MEXICO
TIGHT FM PRICE
NOOH EXPLORATION
EXHIBIT NO 13

DATE: 09/28/81
TIME: 11:27CDT
FILE: RATTLE
PROJ: 0

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 1/ 1/1981

END YR	GROSS OIL PRODUCTION MB	GROSS GAS PRODUCTION MMF	OIL TO NET INTEREST MB	GAS TO NET INTEREST MMF	REVENUE TO INTEREST M$	NET INVESTMENT M$	NET OPER EXPENSES M$	NET INCOME BEFORE FIT M$	CUMULATIVE NET INCOME M$	15.000 PCT CUM. DISC NET INCOME M$
12-81	0.	63.290	0.	53.797	236.477	400.700	4.800	169.023	-169.023	-184.428
12-82	0.	36.690	0.	31.186	137.088	0.	4.800	132.288	-36.735	-77.072
12-83	0.	27.468	0.	23.348	102.631	0.	4.800	97.831	61.096	-8.034
12-84	0.	24.727	0.	21.018	92.390	0.	4.800	87.590	148.686	45.714
12-85	0.	22.265	0.	18.925	83.191	0.	4.800	78.391	227.077	87.543
12-86	0.	20.051	0.	17.043	74.918	0.	4.800	70.118	297.195	120.078
12-87	0.	18.062	0.	15.353	67.487	0.	4.800	62.687	359.882	145.370
12-88	0.	16.697	0.	14.192	62.387	0.	4.800	57.587	417.469	165.575
12-89	0.	15.850	0.	13.473	59.222	0.	4.800	54.422	471.891	182.178
12-90	0.	15.046	0.	12.789	56.217	0.	4.800	51.417	523.308	195.819
12-91	0.	14.284	0.	12.141	53.371	0.	4.800	48.571	571.879	207.023
12-92	0.	13.562	0.	11.528	50.673	0.	4.800	45.873	617.752	216.225
12-93	0.	12.876	0.	10.945	48.110	0.	4.800	43.310	661.062	223.780
12-94	0.	12.226	0.	10.392	45.681	0.	4.800	40.881	701.943	229.981
12-95	0.	11.609	0.	9.868	43.376	0.	4.800	38.576	740.519	235.069
E TOT	0.	324.703	0.	275.998	1213.219	400.700	72.000	740.519	740.519	235.069
AFTER	0.	191.632	0.	162.887	716.013	0.	193.155	522.858	1263.377	257.916
TOTAL	0.	516.335	0.	438.885	1929.232	400.700	265.155	1263.377	1263.377	257.916
CUM.	0.	0.								
ULT.	0.	516.335								

NET OIL REVENUE 0.
NET GAS REVENUE 1929.232
NET PROD REVENUE 0.

5 PCT	655.863	40 PCT	-4.384
10 PCT	398.447	50 PCT	-48.163
15 PCT	257.916	60 PCT	-80.105
20 PCT	168.739	80 PCT	-124.185
30 PCT	60.355	100 PCT	-153.613

CUM NET INC/INV(1) 3.153
GROSS WELLS 1
MONTH IN 1ST YEAR 12
INITIAL W.I., PCT 100.0000

CUM NET PW/INV(1) 0.644
LIFE (YEARS) 55.24
RATE OF RETURN,PCT 39.24
INITIAL N.I., PCT 85.0000

see revised Ex 13

EXHIBIT NO. 13

ASSUMPTIONS AND RESULTS OF ECONOMIC CALCULATIONS

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

ASSUMPTIONS

Drilling and Completion Costs, $	400,700
Expense Interest, %	100
Royalty Interest, %	15
Yield, BBL/MMCF	0
Gas Price, $/MCF	2.389
Severance Tax, %	8
Operating Costs, $/well/yr.	4800
Income Tax Rate, %	48.7
Time Projected, yrs.	25

Producing Rate - Same as Actual Production From Gardner Well No. 1 (413 MMCF in 25 yrs)

RESULTS

Before Income Tax Results:

Discounted Cash Flow Rate of Return, %	7
Payout, yrs.	9.4
Cash Flow, $	259,796

After Income Tax Results:

Discounted Cash Flow Rate of Return, %	6
Payout, yrs.	10.4
Cash Flow, $	142,960

EXHIBIT NO. 13
ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

CURRENT DATE 02/04/81

INVESTMENT ANALYSIS GARDNER AREA WELL NO 1 AT TODAYS COSTS AND PRICE PROJECT LIFE 25 YEARS TAX RATE .48700 DPL .00

INVESTMENT REQUIRED

YEAR	LAND	DEPRECIABLE	DEPLETABLE	WORKING CAP	GOODWILL	TOTAL	SALV PCT	METHOD	INVEST LIFE	TAX CREDIT SUBJ TO INV	PROJECT RECOVERY	IDC PCT	YR
0	0	96,800	303,900	0	0	400,700	.000	4	25.0	96,800	0	.999	0
***	0	96,800	303,900	0	0	400,700				96,800	0		

LOANS REQUIRED

YEAR	PRINCIPAL	PAYOFF PERIOD	INTEREST RATE	DEBT LIQUIDATION	PAYMENT FREQUENCY
TOTAL	0			0	

INPUT VARIABLES -	WORKING INTEREST	BPO	1.0000000		
	REVENUE INTEREST	BPO	.8500000		
	PRODUCTION TAX RATES	GAS	.0800000	COND	.0000000
	PRINCIPAL PRODUCT	GAS			

REVENUE & COST EXTENSIONS

YEAR	GROSS DAILY GAS - MCF	NET ANNUAL GAS - MCF	GAS PRICE	REVENUE GENERATED	GROSS DAILY COND - STB	NET ANNUAL COND - STB	COND PRICE	REVENUE GENERATED	OPERATING COST	PRODUCTION TAX	OVERHEAD COST
0- 1	95	29,776	2.3890	71,135					4,800	5,691	
1- 2	95	29,740	2.3890	71,049					4,800	5,684	
2- 3	88	27,311	2.3890	65,246					4,800	5,220	
3- 4	76	23,762	2.3890	56,767					4,800	4,541	
4- 5	71	22,257	2.3890	53,172					4,800	4,254	
5- 6	58	18,184	2.3890	43,442					4,800	3,475	
6- 7	41	12,964	2.3890	30,971					4,800	2,478	
7- 8	50	15,574	2.3890	37,206					4,800	2,976	
8- 9	58	18,020	2.3890	43,050					4,800	3,444	
9-10	39	12,151	2.3890	29,029					4,800	2,322	
10-11	28	8,917	2.3890	21,303					4,800	1,704	
11-12	24	7,548	2.3890	18,032					4,800	1,443	
12-13	33	10,486	2.3890	25,051					4,800	2,004	
13-14	29	9,257	2.3890	22,115					4,800	1,769	
14-15	36	11,253	2.3890	26,888					4,800	2,151	
15-16	44	13,801	2.3890	32,971					4,800	2,638	
17-18	44	13,725	2.3890	32,789					4,800	2,623	
18-19	29	9,026	2.3890	21,563					4,800	1,725	
19-20	42	13,160	2.3890	31,439					4,800	2,515	
20-21	26	8,287	2.3890	19,798					4,800	1,584	
21-22	22	6,890	2.3890	16,460					4,800	1,317	
22-23	22	7,002	2.3890	16,728					4,800	1,338	
23-24	17	5,407	2.3890	12,917					4,800	1,033	
24-25	17	5,545	2.3890	13,247					4,800	1,060	
TOTAL	413,190	355,113		848,365					120,000	67,869	
	GROSS BBLS (MCF)				GROSS BBLS(MCF)						

EXHIBIT NO. 13

ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

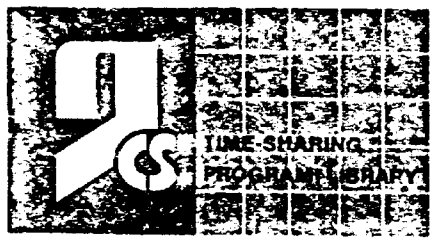
CASH FLOW CALCULATIONS

YEAR	TOTAL INCOME	TOTAL COSTS	DEPREC-IATION	INTEREST	INCOME TAX	TAX DEPLETION	BOOK DEPLETION	NET INCOME	DEBT LIQUIDATION	CASH FLOW
0										400,700-*
0- 1	71,135	10,491	8,117		132,099-		25,481	159,145		192,743
1- 2	71,049	10,484	8,107		25,547		25,451	1,460		35,018
2- 3	65,246	10,020	7,445		23,269		23,372	1,140		31,957
3- 4	56,767	9,341	6,477		19,942		20,335	672		27,484
4- 5	53,172	9,054	6,067		18,531		19,047	473		25,587
5- 6	43,442	8,275	4,957		14,712		15,561	63-		20,455
6- 7	30,971	7,278	3,534		9,817		11,094	752-		13,876
7- 8	37,206	7,776	4,245		12,265		13,327	407-		17,165
8- 9	43,050	8,244	4,912		14,558		15,421	85-		20,248
9-10	29,029	7,122	3,312		9,056		10,398	859-		12,851
10-11	21,303	6,504	2,431		6,023		7,631	1,286-		8,776
11-12	18,032	6,243	2,058		4,739		6,459	1,467-		7,050
12-13	25,051	6,804	2,858		7,494		8,973	1,078-		10,753
13-14	22,115	6,569	2,523		6,342		7,921	1,240-		9,204
14-15	26,883	6,951	3,068		8,215		9,631	977-		11,722
15-16	32,971	7,438	3,762		10,602		11,810	641-		14,931
16-17	35,997	7,680	4,107		11,790		12,894	474-		16,527
17-18	32,789	7,423	3,741		10,531		11,745	651-		14,835
18-19	21,563	6,525	2,460		6,125		7,724	1,271-		8,913
19-20	31,439	7,315	3,587		10,002		11,262	727-		14,122
20-21	19,776	6,384	2,259		5,432		7,091	1,368-		7,982
21-22	16,460	6,117	1,878		4,122		5,896	1,553-		6,221
22-23	16,728	6,138	1,909		4,238		5,992	1,539-		6,362
23-24	12,917	5,833	1,474		2,732		4,627	1,749-		4,352
24-25	13,247	5,860	1,512		2,861		4,745	1,731-		4,526
TOTAL	848,365	187,869	96,300		116,836		303,888	142,972		142,960

* = NET CASH INVESTMENT OR SALVAGE

AFIT
DCF RATE OF RETURN 5.98 PER CENT
PAYBACK PERIOD 10.37 YEARS

BFIT
DCF RATE OF RETURN 6.98 PER CENT
PAYBACK PERIOD 9.43 YEARS



GASWELL Program

User's Manual

2/79

Gas Well Performance Simulation Program

GARRETT COMPUTING SYSTEMS

DALLAS, TEXAS

GAS WELL PERFORMANCE SIMULATOR

Program GASWELL

FEBRUARY 1979

GARRETT COMPUTING SYSTEMS

PREFACE

This manual contains detailed instructions for the use of the subject program in the applications for which it was designated. It is written for engineers, geologists and other professional employees within the petroleum industry. They need not be computer programmers. However, familiarity with the computing system on which this program has been placed is recommended.

This program is a part of an expanding library of time-sharing programs developed by Garrett Computing Systems, Inc. for use by its subscribers. All programs in the GCS library are run-only programs, meaning that they cannot be listed or permanently modified by the user. The terms under which they are made available may vary between programs or may vary with a given program from time to time. Garrett Computing Systems reserves the right to change these terms at its discretion. Questions regarding use of the program library should be directed to:

Garrett Computing Systems, Inc.
Dallas, Texas 75201
Telephone: 741-1026 (A/C 214)

The programs in the GCS library have been extensively tested and to the best of our ability are error-free. However, due to the very complex nature of many of them, GCS cannot warrant that program errors will not be found on occasion. Should this occur, please contact Garrett Computing Systems immediately. Garrett Computing Systems shall not be responsible or liable for the validity or use of the answers derived from the use of the material contained in this booklet or for the program(s) for which it applies.

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TECHNICAL NOTES

ABOUT THE PROGRAM

General

The GASWELL program is used to forecast production from hydraulically fractured gas wells. Reservoir and fracture descriptions are provided by the user along with wellhead pressure and producing rate constraints. The program computes values for producing rate, wellhead pressure, cumulative production and cumulative recovery. Additional features in the program allow the user to compare production history or pressure buildup tests to computed values on the basis of either wellhead pressure or producing rate, and thus determine whether the input reservoir and fracture descriptions are satisfactory.

Input

Input data forms are available on which the user's data should be recorded. These data are subsequently placed in an input file prior to running the GASWELL program. Data for only one case can be placed in a single file. If more than one case is to be run, each case should be placed in a separate file.

Output

The GASWELL program prepares a two-page tabular report for production forecasts. The report is generally stored in an output file which the program creates under a name selected by the user. A description of each page is as follows:

First Page - The first page contains a recap of the input data with the computed value for initial total system compressibility. The information is subdivided into categories for reservoir properties, reservoir geometry, fluid properties, and flowstream data.

Second Page - This page, entitled "Predicted Performance", contains a printout by time frame of the forecasted variables. The values tabulated on this page are time, flowing wellhead pressure, flowing bottom-hole pressure, average shut-in reservoir pressure, producing gas rate, cumulative production, cumulative percent recovery, and Z-factor at average reservoir conditions. If the user exercises the option of providing constraints from the terminal during execution, the forecasted values are printed directly on the terminal in addition to being placed in the output data file.

When a comparison based on observed history is performed, the output is different from that of a forecast. As with a production forecast, a recap of the input data is provided on the first page of output. The second page, entitled

"Performance Comparison", contains a table of computed and observed values versus time. The tabulated values are time, observed wellhead pressure, calculated wellhead pressure, observed rate, and calculated rate. In addition to being placed in the output data file, the performance comparison report is also printed on the user's terminal.

Processing Technique

The processing technique used by the GASWELL program is outlined below:

1. All input data is read and converted to standard units.

2. The initial total system compressibility is computed.

3. Real gas pseudo-pressures are computed for pressures ranging up to the initial reservoir pressure based on the gas gravity and computed values for gas viscosity and Z-factor.

4. Internal tables are generated for dimensionless pressure drop versus dimensionless time based on the user's reservoir geometry. These solution tables are discussed further in the Technical Notes section.

5. A time-step is taken and the deliverable rate against the scheduled wellhead pressure is computed. If this rate is in excess of the maximum allowable rate, the wellhead pressure corresponding to the allowable rate is computed.

6. Production for the time interval and the flowing bottom-hole pressure are both calculated based on the rate determined in Step 5.

7. The average reservoir pressure is computed by material balance based on the production increment established in Step 6.

8. Cumulative percent recovery and Z-factor at reservoir conditions are computed.

9. The above process is repeated from Step 5 until the ending time or minimum producing rate is reached.

10. The output report is printed.

Principal Features

The following features are included in the GASWELL program.

1. Production forecasts can be obtained based on production constraints such as minimum wellhead pressure and maximum allowable rate. Production constraints can be varied as a function of time.

2. The forecast may be started at any time subsequent to the specified initial date. In addition, the user may specify the desired output frequency.

3. Observed wellhead pressures or production rates may be compared to computed values. Short-term or long-term data may be used.

4. A rectangular drainage shape may be specified along with the well location within the drainage area.

5. Either uniform flux or infinite conductivity fractures may be considered.

6. Real gas pseudo pressures are computed based on input gas gravity. Adjustments to gas properties can be made for the presence of H_2S, CO_2 and N_2.

7. An interactive mode exists which allows the user to control the progress of either production forecasts or production comparisons.

Assumptions

The following assumptions have been incorporated into the calculations.

1. The fracture is vertical.

2. The fracture can be characterized either as possessing infinite conductivity or having uniform mass flux within the fracture plane.

3. The reservoir matrix has constant properties throughout.

4. A single producing layer exists of uniform thickness.

5. The wellbore is located at the center of the fracture.

6. The fracture is parallel to the drainage boundary.

7. The drainage boundary is either square or rectangular.

8. Fluid flow within the reservoir is single-phase gas.

Program Calculation Step Size Selection

For increased accuracy in its internal predictive calculations the program selects an initial time-step size of one-half day, then doubles this size for each succeeding step until a step size of one month is reached. This value is then held constant until three years have elapsed since the calculations began. Quarterly steps are taken until a total of six years has passed, whereupon the step size is set at six months for the duration of the run.

The program will automatically alter these time step sizes to accommodate output dates specified on lines 701-799 (or input as response to question on output frequency). Thus the user may override the built-in time steps by specifying each desired interval on the 701-799 lines.

PREPARATION OF DATA

Form Available

A GASWELL input form has been developed for recording all necessary input data. A copy has been included at the back of this manual. Additional copies may be reproduced from this manual or ordered in pad form from GCS.

Multiple Cases

Data for each case (one input data sheet) should be placed in a separate computer file before processing.

Line Numbers

The line numbers shown on the input data form serve two purposes. They tell the program the nature of the data on the line and permit proper sequencing before processing. Only the line numbers indicated on the form or in this chapter may be used.

Data Format

With the exception of lines 101-103, all input is in free form. This means that the basic requirement for spacing of data is that each word entry be separated from the next by at least one blank space. Inclusion of decimal points is permitted. All data spaces must be filled in on each line. Data items not used must contain a zero instead of a blank.

Lines 101-103 (Run Description)

101	YOURWELL NO. 3
102	ROUNDHOUSE FIELD
103	FREMONT CO., WYOMING

These three lines contain heading information for the printout. Recommended information for these lines includes well name and number, field and zone, and county and state. Any alphanumeric descriptions can be placed on these lines provided, however, that the maximum number of characters, including blanks, does not exceed 24 on any line.

Line 200 (Reservoir Data)

	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation, %	Temperature of Zone, °F
200	.53	4.7	115	53	197

This line contains the basic reservoir parameters. All five items on this line are required and are described as follows:

1. Permeability, Md. - Enter the matrix permeability of the producing interval.

2. Porosity, % - Specify the total porosity of the producing interval as a percent of the bulk volume.

3. Net Pay, Feet - Enter the net thickness of the producing interval. The program assumes that the fracture extends from the top to the bottom of the net interval and that the interval is of constant thickness throughout the drainage area.

4. Liquid Saturation, % - Enter the total liquid saturation for the producing interval. The program assumes this value to be constant throughout the drainage area and for the life of the project.

5. Temperature of Zone, Degrees F - Show the average reservoir temperature. The program assumes this value to be constant for the project life.

Line 210 (Fracture Data)

	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210	500	2640	2640	1320	1320

All items on this line are required. The data on this line describe the fracture length, the size of the drainage area and the position of the fracture within the drainage area. Note that the fracture must be oriented in the X-direction. Refer to Figure 1 for the discussion of the following items:

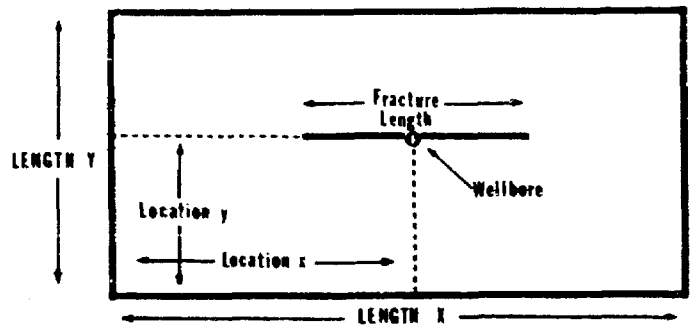

Fig. 1

1. Fracture Length, Feet - Enter the tip-to-tip fracture length in feet. If a value less than one foot is entered, the program will assume that the item entered is a wellbore radius and that no fracture exists.

2. Drainage Area Length X, Feet - Enter the length corresponding to length X in Figure 1. This is the total length of the drainage area in the X-direction.

3. Drainage Area Length Y, Feet - Enter the length corresponding to length Y in Figure 1. This is the total length of the drainage area in the Y-direction.

4. Well Location x, Feet - Enter the distance corresponding to location x in Figure 1. This is the x-component of the wellbore location within the drainage area.

5. Well Location y, Feet - Enter the distance corresponding to location-y in Figure 1. This is the y-component of the wellbore location within the drainage area.

Line 220 (Flowstream Data)

	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (Inches)	Liquid Comp. (V/V/V/PSI)
220	1.995	0	9750	0	3.8

This line must always be present in a data file. The items are described as follows:

1. Flowstream O. D., Inches - Enter the outer diameter of the producing fluid stream within the wellbore. For tubing flow this entry will be the tubing I. D. For annular flow this entry will be the casing I. D. If wellbore pressure losses are not being considered, enter a zero.

2. Flowstream I. D., Inches - Enter the inner diameter of the producing fluid Stream. This entry only applies to annular flow and corresponds to the O. D. of the tubing. For tubing flow enter a zero for this item. If wellbore pressure losses are not being considered, enter a zero.

3. Zone Depth, Feet - Enter the depth to the mid-point of the producing interval. If wellbore pressure losses are not being considered, enter a zero.

4. Pipe Roughness, Inches - Specify the absolute pipe roughness in inches. If a zero is entered the program will use a default value of 0.0018 inches in the wellbore hydraulics calculations.

5. Liquid Comp., V/MMV/PSI - This compressibility should reflect that part of the total system compressibility not accounted for by the gas compressibility. This entry is -

$$C = S_l C_l + C_f$$

where,

S_l = liquid saturation, percent

C_l = actual liquid compressibility, V/MM/PSI

C_f = formation compressibility, V/MMV/PSI

The importance of this entry depends on the magnitude of the gas compressibility. If the gas compressibility is large, this item will not significantly affect the calculations.

Line 230 (Fluid Data)

	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230	.68	.93	.12	1.0	0

This line is required in all input data files. The entries are described as follows:

1. Gas Gravity, (Air=1) - Enter the specific gravity of the gas.

2. Liquid Gravity, (Water=1) - Enter the specific gravity of the liquid. If the liquid consists of both condensate and water, enter a weighted specific gravity based on the proportion of each liquid in the produced stream. If no liquid is present in the flowstream, enter a zero.

3. H2S Diluent, Mol % - Enter the hydrogen sulfide content of the produced gas. When used, values for N_2 and CO_2 should also be entered.

4. CO2 Diluent, Mol % - Enter the carbon dioxide content of the produced gas. When used, values for H_2S and CO_2 should also be entered.

5. N2 Diluent, Mol % - Enter the nitrogen content of the produced gas.

Line 240 (Optional Data)

	Non-Darcy Flow[1] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
240	0	0	1	14.025	60

The use of this line is optional. The entries are described as follows:

1. Non-Darcy Flow Coefficient, Days/MCF - This entry enables the user to introduce a rate-dependent dimensionless pressure drop into the calculations. This is normally done when it has been observed that the skin factor is rate-dependent. The coefficient represented here is the slope of a plot of skin factor versus producing rate.

2. Skin Factor, Dimensionless - This entry is sometimes used to approximate the increased flow efficiency of a fracture by a skin factor. This should only be done when a wellbore radius has been entered on line 210. If a fracture length has been entered on line 210, this entry will normally be zero.

3. Fracture Type - Enter a zero for an infinite conductivity fracture. Enter a 1 for a uniform flux fracture. If line 240 is not being used, the program will default to use of an infinite conductivity fracture.

4. Standard Pressure, PSIA - Enter the standard pressure. If no entry is supplied the program will assume a value of 14.65 psia.

5. Standard Temperature, Degrees F - Enter the standard temperature. If no entry is supplied the program will assume a value of 60 degrees F.

Line 700 (Initial Time and Pressure)

	Beginning Date[6] Mo.	Day	Year	Initial Reservoir, PSIG	Minimum[7] Rate MCF/D
700	1	1	79	3975	1

Line 700 is required. The entires are described as follows:

1. Beginning Date, Month-Day-Year - This entry establishes the beginning time of the run. The reservoir pressure at this time should be uniform throughout the drainage area.

2. Initial Reservoir Pressure, PSIG - Enter the reservoir pressure corresponding to the beginning rate.

3. Minimum Rate, MCF/D - Specify a rate which will serve as a cutoff for the calculations. This rate may be regarded as the economic limit for the well. This value may be negative, which can be useful in preventing the calculations from stopping during a comparison run when the user is trying to match very low rates (or zero rates in the case of a build-up test).

Line 701-799(Limiting Data)

	Limiting Date[6] Mo.	Day	Year	Limiting Wellhead Flow, PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701	1	1	80	900	3000	5.7	90
702	6	1	81	300	3000	9	90
703	1	1	83	300	3000	16	90

These lines are used to supply the program with information to govern the producing conditions. The information is time-scheduled as described below:

1. Limiting Date, Month-Day-Year - This entry supplies the time through which the subsequent information on the line will apply. The first date supplied here must be later than the beginning date specified on line 700. Note: The day can be entered as a decimal fraction for instances where limiting values change within the span of a day.

2. Limiting Wellhead Flowing Pressure, PSIG - This entry represents the minimum permissible wellhead pressure. If the well rate is restricted, due to an allowable for example, the calculated wellhead pressure will always be higher than this input value. If the well is producing at maximum capacity the wellhead pressure will be maintained at the specified value as the rate declines. If observed data is being entered for comparison purposes, enter the observed wellhead pressure.

3. Limiting Gas Rate, MCF/D - This entry represents the maximum permissible gas production rate. The well will be limited to this rate even if flow capacity against the limiting wellhead pressure is greater. If observed data is being entered for comparison purposes, enter the observed producing rate.

4. Liquid Rate, Bbls./MMCF - The program will adjust the wellbore hydraulics calculations to account for the presence of liquids in the flowstream. It it is desired to increase the wellbore pressure gradient to account for liquids, enter the total liquid rate in Bbls./MMCF. Otherwise, enter a zero.

5. Wellhead Temperature, Degrees F - Enter the wellhead flowing temperature.

Up to 99 lines of limiting data may be included in a single file.

RUNNING THE PROGRAM

Setting Up an Input Data File

The user must place his input data into a timesharing file prior to running program GASWELL. Data for only one case may be placed in a single file.

Program Operation and Output

There are basically four ways GASWELL can be run:

1. As a prediction with future production constraints specified on lines 701-799 in the input data file.

2. As a prediction with future production constraints specified interactively on the terminal during execution.

3. As a comparison of computed to observed wellhead pressures given specified producing rates, with the tests input on lines 701-799.

4. As a comparison of computed to observed producing rates given specified wellhead pressures, with these tests input on lines 701-799.

Since each of these methods requires slightly different procedures to run, the following examples were prepared (one for each of the four methods above) to illustrate the dialogue required to use these methods and the resulting output for each. Comments with respect to the circled numbers are as indicated below.

In all cases these output reports are located in user-named output files and can be listed on the terminal after execution of the program.

Every GASWELL execution will generate two pages of output. The first output page will be the same regardless of which type run is being made. For this reason page one will be discussed first and omitted from the individual examples.

1. The first three lines printed in the upper left-hand corner are the information contained on input data lines 101-103.

2. The following items appear under the heading "Reservoir Properties":

   a) Date - The date on the 700-line of the input data. This is the initial time-zero date.

   b) Pressure, Psig - The input reservoir pressure at the initial date. This pressure is assumed to be uniform throughout the drainage area.

GENERAL PAGE ONE EXAMPLE
OUTPUT FOR EACH GASWELL (1)
CALCULATION MADE

1/26/79 10:25:00

F R A C T U R E D G A S W E L L

P R O D U C T I O N P E R F O R M A N C E

RESERVOIR PROPERTIES (2)

DATE	12-31.00-78	LIQUID SAT., PCT.	40.0
PRESSURE, PSIG	3000.0	TEMPERATURE, DEG. F.	200.0
PERMEABILITY, MD.	1.000	TOTAL COMP., V/MMV/PSI	176.9
POROSITY	25.0	NON-DARCY FLOW COEFF.	0.0
NET PAY, FT.	50.0	SKIN	0.0

RESERVOIR GEOMETRY (3)

FRACTURE LENGTH, FT.	400.0	FRACTURE TYPE	I.C.
X-LENGTH, FT.	2640.	X-LOCATION, FT.	1320.
Y-LENGTH, FT.	2640.	Y-LOCATION, FT.	1320.

FLUID PROPERTIES (4)

GAS GRAVITY	0.600	H2S, MOL. FCT.	0.00
LIQUID GRAVITY	0.000	CO2, MOL. FCT.	0.00
STANDARD PRESSURE, PSIA	14.65	N2, MOL. FCT.	0.00
STANDARD TEMP., DEG. F.	60.0		

FLOWSTREAM DATA (5)

FLOWSTREAM O.D., IN.	1.995	TOTAL DEPTH, FT.	7000.
FLOWSTREAM I.D., IN.	0.000	ABS. PIPE ROUGH., IN.	0.00180

c) Permeability, Md. - The input reservoir matrix permeability.

d) Porosity, % - The input reservoir matrix porosity.

e) Net Pay, Ft. - Input net pay in the producing interval.

f) Liquid Saturation, % - Combined input hydrocarbon and water saturation in the drainage area.

g) Temperature, Degrees F - The average input reservoir temperature.

h) Total Compressibility, V/MMV/PSI - The computed total compressibility at initial reservoir conditions.

i) Non-Darcy Flow Coefficient - The input non-Darcy flow coefficient. Units are MM Days/Mcf.

j) Skin - The input skin factor.

3. The following items appear under the heading "Reservoir Geometry":

a) Fracture Length, Ft. - The input tip-to-tip fracture length. If a fracture is not being used, this item will be shown as a wellbore radius.

b) X-length, Ft. - The drainage area X length input on line 210.

c) Y-Length, Ft. - The drainage area Y length input on line 210.

d) Fracture Type - The input fracture type will be printed as "I.C." for infinite conductivity fractures and "U.F." for uniform flux fractures.

e) X-Location Ft. - The wellbore x location input on line 210.

f) Y-Location, Ft. - The wellbore y location input on line 210.

4. The following items appear under the heading "Fluid Properties":

a) Gas Gravity - The input gas specific gravity (Air=1.0).

b) Liquid Gravity - The input liquid specific gravity (Water=1.0).

c) Standard Pressure - The input standard pressure, psia.

d) Standard Temperature, Degrees F - The input standard temperature.

e) H2S, CO2, N2, Mol. Percent - The input mol percentage of diluents.

5. The following items follow the heading "Flowstream Data":

a) Flowstream O.D., Inches - The input O.D. of the flowstream. This will be the tubing I.D. for tubing flow, or the casing I.D. for annular flow.

b) Flowstream I.D., Inches - The input I.D. of the flowstream. This will be 0 for tubing flow, or the tubing O.D. for annular flow.

c) Total Depth, Ft. - The input depth to the mid-point of the producing interval.

d) Absolute Pipe Roughness, In. - The input absolute pipe roughness.

Example 1
Production Forecast

In this example the user wishes to predict the performance of the well and has scheduled all future production constraints by using lines 701-799 in the input data file. The execution dialogue is presented first, followed by the second page of the output report.

```
RUN GASWELL (1)
GASWEL @ 10:56:00 ON  1/29/79


INPUT FILE,OUTPUT FILE, & P-CODE --?XX1 XX1OUT 2 (2)


ENTER TYPE OF RUN:
 0 = PREDICTIVE
 1 = COMPARISON BASED ON WELLHEAD PRESS
 2 = COMPARISON BASED ON RATE ---?0 (3)


ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
OUTPUT TIME INTERVALS (MOS.) --?1 1 79 12 (4)


WANT TO ALTER INPUT DATA --?YES (5)


LINE, WORD, VALUE --?701 4 1000

LINE, WORD, VALUE --?0 0 0

WANT TO ALTER INPUT DATA --?NO

FILE - XX1OUT   SAVED. (6)
READY.
```

1. This command retrieves the GASWELL program from the GCS library and places it in execution.

2. The input file is the file which has been previously prepared and contains the input data for the program. The output file contains the reports generated by the program. The P-code refers to the type terminal on which the output reports are to be printed. Permissible P-codes and their meanings are as follows:

   1 - Teletypes, Terminets, TI Silent700's and others that do not have form-feeding capabilities and thereby must rely on the counting of lines to establish 11-inch pages.

   2 - DCT 500's, DECwriters, paging Terminets, Beta's and similar form-feeding, wide-carriage terminals.

   3 - Conventional line printers that require a numeric "1" in the first column for top-of-form.

3. If a production forecast (predictive run) is desired, a zero is entered in response to the program's question concerning the type of run.

4. For predictive runs the program will request a starting output date and the number of months between output lines. The starting date will normally be the first date on which output is desired. This date must be later than the date specified on line 700 of the input data form. The number of months between output lines enables the user to schedule production monthly, quarterly, etc. The maximum number of months allowed between output lines is 12.

5. When the calculations are complete the program will ask the question "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the run recomputed. The program will ask for:

   a) The line number of the input data line on which a change is wanted.

   b) The position of the data item on the line.

   c) The new data value to be inserted.

   Using this method, any number of data items can be changed. Three zeros are used to indicate that the OVER sequence should terminate and the new run should begin. In this example the user is changing the fourth value on line 701 to 1000 (reducing the input line pressure from its original value of 1500 psi to 1000 psi).

6. This indicates that the file containing the output report has been saved.

The second page of the report for each run made in Example 1 is shown on the opposite page. Notice that the first run reflects the projection for the well against a 1500 psi line pressure, while the second run illustrates the improvement expected due to a lower line pressure of 1000 psi (subject to a maximum well rate of 10,000 Mcf/D).

7. The first three lines printed in the upper left-hand corner contain the information input on lines 101-103.

8. The following items appear under the heading "Predicted Performance":

   a) Month-Day-Yr - The date for which the following items on the output line apply. The dates for output are governed either by the terminal response to the question asking for an output schedule or the dates on the 701-series lines.

   b) Flowing WHP, Psig - The flowing wellhead pressure. This pressure will either be the minimum specified wellhead pressure or a computed wellhead pressure, depending upon whether the well is producing at the maximum allowed rate.

   c) Flowing BHP, Psig - The flowing bottom-hole pressure at the producing depth.

   d) Avg. S.I. BHP, Psig - The average reservoir pressure at the specified date.

   e) Gas Rate, M/D - The average gas rate for the preceding output interval. Note that this value is not the well rate for the date printed at the left.

   f) Cum. Gas, BCF - Cumulative gas production.

   g) Cum. Rec., Pct. - Cumulative percent recovery of the initial gas-in-place.

   h) Z-Factor - The reservoir Z-factor at the average reservoir pressure and average reservoir temperature.

EXAMPLE NUMBER 1 (7)
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(8) P R E D I C T E D P E R F O R M A N C E

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1500.0	2657.6	2996.4	9774.	0.0098	0.10	0.9072
1- 1.000-80	1500.0	1907.4	2378.0	4986.	1.8296	19.59	0.8956
1- 1.000-81	1500.0	1791.2	2064.1	2716.	2.8237	30.23	0.8968
1- 1.000-82	1500.0	1754.5	1902.9	1431.	3.3462	35.83	0.8994
1- 1.000-83	1500.0	1744.5	1821.0	735.	3.6144	38.70	0.9013
1- 1.000-84	1500.0	1741.9	1780.1	366.	3.7480	40.13	0.9023
1- 1.000-85	1500.0	1741.2	1760.4	176.	3.8122	40.82	0.9027
1- 1.000-86	1500.0	1741.2	1751.5	79.	3.8411	41.13	0.9029
1- 1.000-87	1500.0	1740.9	1745.5	54.	3.8607	41.34	0.9031
1- 1.000-88	1500.0	1741.3	1743.5	17.	3.8670	41.40	0.9031
1- 1.000-89	1500.0	1741.0	1742.3	11.	3.8711	41.45	0.9031

Report Resulting from Original Data
(Page 2)

EXAMPLE NUMBER 1
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(8) P R E D I C T E D P E R F O R M A N C E

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1383.0	2645.1	2996.3	10000.	0.0100	0.11	0.9072
1- 1.000-80	1000.0	1553.0	2230.5	6265.	2.2968	24.59	0.8962
1- 1.000-81	1000.0	1319.1	1800.3	3784.	3.6818	39.42	0.9018
1- 1.000-82	1000.0	1218.5	1543.9	2309.	4.5246	48.44	0.9099
1- 1.000-83	1000.0	1179.0	1388.0	1401.	5.0361	53.92	0.9162
1- 1.000-84	1000.0	1163.9	1293.8	839.	5.3425	57.20	0.9202
1- 1.000-85	1000.0	1158.2	1237.9	495.	5.5237	59.14	0.9227
1- 1.000-86	1000.0	1156.4	1205.7	284.	5.6274	60.25	0.9241
1- 1.000-87	1000.0	1155.8	1184.4	188.	5.6962	60.99	0.9251
1- 1.000-88	1000.0	1155.1	1172.8	102.	5.7334	61.39	0.9256
1- 1.000-89	1000.0	1155.6	1165.7	63.	5.7563	61.63	0.9259

Report Resulting from Data as Modified
in Response to "WANT TO ALTER INPUT DATA--?"
(Page 2)

Example 2
Production Forecast - Interactive

This example illustrates use of the program in the predictive mode when the user desires to control the production constraints at the terminal while the program is executing. This mode of execution can be invoked by not including any of the 701-799 lines in the input data file. The program will then ask for the production constraints interactively.

1-3 Same as Example 1.

4. Same as Example 1. Here the user is requesting quarterly output.

5. Since no 701-799 lines have been included in the input data file the program asks the user for information that would normally be supplied on those lines. The program will then proceed to compute results until the date supplied as the first item has been reached.

6. When the interactive mode of execution is being used, a recap of the predicted performance is printed on the terminal until the last supplied time has been reached. This enables the user to monitor the progress of the calculations.

7. Three responses to the "MORE--?" question are valid: NO, OVER, and YES.

   NO - This response causes the run to terminate.

   OVER - This response allows the user to change his input data for a new run. The use of this response is exactly the same as illustrated in Example 1 where "YES" is answered to the question "WANT TO ALTER INPUT DATA--?".

   YES - This response indicates that the interactive run is to continue with a new set of production constraints.

8. Following an "OVER" or "YES" response, the program does not allow the user to change the output schedule. It proceeds directly to the question asking for a set of production constraints. Here the user is requesting another year of output with the same line pressure as before.

9. The predicted performance for the new run is printed.

10. The "NO" response to the "MORE--?" question terminates the calculations.

11. The program indicates the output file containing the complete report has been saved. The output file in this case will contain one report for both the original run and the subsequent run. The information will be exactly the same as the recaps shown on the dialogue page, but the output will be continuous, that is all nine lines of projections will appear under one set of headings.

```
RUN GASWELL
 GASWEL @ 10:53:00 ON  1/29/79 (1)


 INPUT FILE,OUTPUT FILE, & P-CODE --?XY2 XX2OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS (3)
  2 = COMPARISON BASED ON RATE ---?0


 ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
 OUTPUT TIME INTERVALS (MOS.) --?1 1 79 3 (4)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 80 1500 5000 0 100 (5)

                FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR    WHP        BHP        SI BHP     RATE       GAS        REC.       Z FAC. (6)
------------    PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---     ------
 1- 1.000-79     2254.0     2825.6     2998.1     5000.      0.0050     0.05      0.9073
 4- 1.000-79     1741.3     2281.7     2832.2     5000.      0.4550     4.87      0.9007
 7- 1.000-79     1550.6     2087.1     2667.5     5000.      0.9100     9.74      0.8945
10- 1.000-79     1500.0     1983.2     2530.8     4721.      1.3444    14.39      0.8950
 1- 1.000-80     1500.0     1925.7     2412.3     4089.      1.7205    18.42      0.8955


 MORE --?YES (7)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 81 1500 5000 0 100 (8)

                FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR    WHP        BHP        SI BHP     RATE       GAS        REC.       Z FAC. (9)
------------    PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---     ------
 4- 1.000-80     1500.0     1880.4     2310.9     3534.      2.0422     21.87     0.8959
 7- 1.000-80     1500.0     1845.4     2223.4     3046.      2.3194     24.83     0.8962
10- 1.000-80     1500.0     1818.2     2147.3     2613.      2.5597     27.41     0.8965
 1- 1.000-81     1500.0     1797.5     2082.7     2230.      2.7649     29.60     0.8967


 MORE --?NO (10)

 FILE - XX2OUT    SAVED. (11)
 READY.
```

Example 3
Comparison with Observed Data

This example illustrates use of the program to compare observed production history with computed results. This comparison will be on the basis of wellhead pressure.

As discussed previously, when comparisons are being performed the observed data should be entered in chronological sequence on the 701-799 lines on the input data form. For a comparison based on wellhead pressure the program will force the well to produce at the input rates and compute the corresponding wellhead pressures. The computed pressures will not be affected in any way by the input pressures. A report showing the comparison will then be produced.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on wellhead pressure.

4. When comparison runs are being performed, a table is printed on the terminal which shows the test times along with computed and observed values. In this example the observed and calculated rates are shown to be the same since only wellhead pressures are actually being computed. The observed pressure will be the test pressure which is tabulated along with the computed pressure.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated wellhead pressures are too low so the user increases the permeability (input as the first word on line 200) to one millidarcy in an attempt to get a better history match. The second table shows a good match on pressure so the run is terminated.

6. The program indicates that the file containing the output has been saved.

The second page of the output report will show the same information contained in the table that appears on the terminal during execution, but with the addition of three lines of heading information and a title, "PERFORMANCE COMPARISON". In this example, four pages of output would result; a first and second page for the original run, and a first and second page for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:51:00 ON  1/29/79

 INPUT FILE,OUTPUT FILE & P-CODE --?XXS XX3OUT 2 (2)

 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?1 (3)

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D----

  1- 1.000-78       1500.0     1394.9     9540.     9540.
  2- 1.000-78       1500.0     1202.5     6590.     6590.
  3- 1.000-78       1500.0     1151.4     6160.     6160. (4)
  7- 1.000-78       1500.0     1180.4     5040.     5040.
  1- 1.000-79       1500.0     1259.1     3910.     3910.


 WANT TO ALTER INPUT DATA --?YES (5)


 LINE, WORD, VALUE --?200 1 1


 LINE, WORD, VALUE --?0 0 0

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D----

  1- 1.000-78       1500.0     1507.5     9540.     9540.
  2- 1.000-78       1500.0     1518.5     6590.     6590.
  3- 1.000-78       1500.0     1510.4     6160.     6160.
  7- 1.000-78       1500.0     1502.0     5040.     5040.
  1- 1.000-79       1500.0     1497.8     3910.     3910.


 WANT TO ALTER INPUT DATA --?NO

 FILE - XX3OUT    SAVED. (6)
 READY.
```

Example 4
Comparison with Observed Data

This example illustrates the use of the program when comparing computed rates to observed values. In this case the program is forced to produce at the wellhead pressures entered on the 701-799 lines. The corresponding computed rates can then be compared to the observed rates.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on rate.

4. As with the comparison in the prior example, times along with observed and calculated values are tabulated at the user's terminal. In this case the observed and calculated pressures are identical, with the variance between the observed and computed rates being illustrated.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated rates are too high, so the user reduces the fracture length (input as the first word on line 210) to 400 feet. A good match on producing rates results so the run is terminated.

6. The program indicates that the file containing the output report has been saved. As in the previous example, the output will consist of four pages -- one two-page set for the original run and another two-page set for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:41:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX4 XX4OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?2 (3)

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D----

  1- 1.000-78        1500.0     1500.0     9540.     9857.
  2- 1.000-78        1500.0     1500.0     6590.     6951. (4)
  3- 1.000-78        1500.0     1500.0     6160.     6495.
  7- 1.000-78        1500.0     1500.0     5040.     5172.
  1-10.000-79        1500.0     1500.0     3545.     3670.


 WANT TO ALTER INPUT DATA --?YES (5)


 LINE, WORD, VALUE --?210 1 400


 LINE, WORD, VALUE --?0 0 0

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D----

  1- 1.000-78        1500.0     1500.0     9540.     9547.
  2- 1.000-78        1500.0     1500.0     6590.     6585.
  3- 1.000-78        1500.0     1500.0     6160.     6162.
  7- 1.000-78        1500.0     1500.0     5040.     4935.
  1-10.000-79        1500.0     1500.0     3545.     3557.


 WANT TO ALTER INPUT DATA --?NO

 FILE - XX4OUT    SAVED. (6)
 READY.
```

TECHNICAL NOTES

1. The procedures used in GASWELL to compute dimensionless pressure versus dimensionless time are based upon the following work: Gringarten, A. C., Ramey, H. J., Jr., and Ravhavan, R.: "Unsteady-State Pressure Distributions Created by a Well with a Single Infinite-Conductivity Vertical Fracture", Soc. Pet. Eng. J. (Aug. 1974) 347-360; AIME Trans., Vol. 257.

2. The constant-rate solutions from Gringarten, et. al. are converted to variable-rate solutions needed by GASWELL using superposition.

3. The average reservoir pressure is computed by subsequent time periods by material balance.

4. The pressure drop in the wellbore is calculated using the technique of Cullender and Smith.

GASWELL Simulator
Input Data Form
2/79

WELL DESCRIPTION:

Well Name & No.

Field & Zone

County & State

RESERVOIR AND WELL DATA:

Optional

TIME, PRESSURE & RATE DATA:

Required Line

Use lines 701-799 to enter limiting time, wellhead pressure & rates. If omitted, program will ask for limiting conditions.

101					
102					
103					
	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation,%	Temperature of Zone, °F
200					
	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210					
	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (inches)	Liquid Comp. (V/MMV/PSI)
220					
	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230					
	Non-Darcy Flow[3] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
240					
	Beginning Date[6] Mo. Day Year	Initial Reservoir,PSIG	Minimum[7] Rate MCF/D		
700					
	Limiting Date[6] Mo. Day Year	Limiting Well-head Flow,PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701					
702					
703					
704					
705					

NOTES:

(1) If value less than 1 foot entered, it will be used as the wellbore radius with no fracture.

(2) Distance measured from lower left corner of rectangular drainage area.

(3) Used to handle turbulence.

(4) Dimensionless pressure drop due to skin effects.

(5) Enter zero for infinite conductivity fracture. Enter 1 for uniform flux fracture.

(6) Fractional day number may be entered; for example, "7 9.25 77" would be 6 hours(.25 days) into the ninth day of July 1977.

(7) Calculations will stop when the specified rate is reached.

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KOCH EXPLORATION COMPANY

DETAIL WELL ESTIMATE

EXHIBIT #12

LEASE NO. _____ AFE NO. _____ OUR W. I. _____

LEASE NAME AND WELL NO. Gardner Area LOCATION _____

DISTRICT _____ COUNTY San Juan STATE New Mexico FIELD OR AREA _____

EST. T. D. 6200 FT. OPERATOR Koch Exploration DATE February, 1981

		Producer	Dry Hole
Drilling Intangibles:			
1 – LOCATION EXPENSE:			
DIG PITS $ 2,000	FILL PITS $ 2,000	ROADS-BRIDGES $ 4,000	
DRGD.-GRADE $ _____	SURV. LOCATION $ 300	DAMAGES $ 500	
STATE-MISC. FEES $ _____	MISC. (LIST) $ _____		
	FEATURE TOTAL	$ 8,800	$ _____
11 – RIG COSTS:	17 days @ 5,800		
DRILLING _____ FT. AT $ _____/FT.	$ _____	DAY WORK $ 98,600	
BITS-REAMERS $ 6,000	WATER $ _____	MIRT-MORT $ 8,000	
COMPRESSORS $ _____	CABLE TOOLS $ _____	FUEL-SUPPLIES $ _____	
BOILER CHG $ _____	SWAB UNIT $ 5 days @ 1,400 = 7,000		
MISC. (LIST) $ _____			
	FEATURE TOTAL	$ 131,600	$ _____
20 – CEMENT AND SERVICES:			
CEMENT AND SERVICE: SURFACE $ 700	INTR. $ 5,100	PROD $ 2,000	
FLOATS $ _____	CENTRALIZERS $ _____	GUIDES $ _____	
STAGE TOOLS $ _____	SCRATCHERS $ _____	PLUGGING $ _____	
SQUEEZES $ _____	MISC (LIST) $ _____		
	FEATURE TOTAL	$ 7,800	$ _____
21 – DRILLING FLUIDS:			
MUD $ 15,000	CHEMICALS $ _____	OIL $ _____	
MISC. (LIST) $ _____			
	FEATURE TOTAL	$ 15,000	$ _____
22 – WELL SURVEYS AND TESTING:			
CORING $ _____	CORE HEADS $ _____	TEMP. SURV. $ 300	
CALIPER SURV. $ _____	ELEC. SURV. $ 15,300	MUD LOG $ _____	
D. S. T. S _____	AT $ _____ EA. $ _____	RADIATION LOG $ _____	
MISC. (LIST) $ _____			
	FEATURE TOTAL	$ 15,600	$ _____
23 – SPECIAL SERVICES:			
PERFORATING $ 10,000	PLUGS-RETAINERS $ _____	ACID $ _____	
FRAC. $ 65,000	MISC. TOOL RENTAL $ _____		
	FEATURE TOTAL	$ 75,000	$ _____
30 – LABOR AND SUPERVISION:			
CO. LABOR $ _____	SUPV.-PERS. EXP. $ _____	OVERHEAD $ _____	
DIST EXP. $ _____	CONTRACT LABOR $ _____	COMMUNICATION $ _____	
	FEATURE TOTAL	$ _____	$ _____
40 – TRANSPORTATION:			
CO. CARS $ 500	AIR TRAVEL $ _____		
TRUCKING (CASING, TUBING, CABLE TOOLS) $ 10,000			
	FEATURE TOTAL	$ 10,500	$ _____
41 – OTHER COSTS:			
(ITEMIZE) _____			
	FEATURE TOTAL	$ _____	$ _____
45 – CONTINGENCY: 15%		$ 39,600	$ _____
	TOTAL INTANGIBLES	$ 303,900	$ _____
Well Equipment:			
51 – CASING AND TUBING (SIZE, WT., GRD., CPLG., NEW OR USED)			
200 FT. OF 28# 10-3/4"	AT $ 17.91 /FT.	$ 3,600	
3600 FT. OF 20 & 26# 7"	AT $ 8.00 /FT.	$ 28,800	
6200 FT. OF 10.5# 4-1/2"	AT $ 5.15 /FT.	$ 31,900	
6000 FT. OF 4.7# 2-3/8"	AT $ 2.92 /FT.	$ 17,500	
	FEATURE TOTAL	$ 81,800	$ _____
52 – CASING HD. $ 1,000	XMAS TREE OR PUMPING CONNECTION $ 2,000	$ 3,000	$ _____
53 – PUMPING UNIT $ _____	ENGINE OR ELECTRIC MOTOR $ _____	$ _____	$ _____
55 – SUCKER RODS _____	$ _____		
PUMP $ _____	POLISHED ROD $ _____	FEATURE TOTAL	$ _____ $ _____
62 – TANKS 1	AT $ 3,850 EA. $ _____	BUILD BATTERY $ _____	
FLOWLINES 100 FT. OF _____	AT $ 2.50 PER FT. $ 250		
LAY FLOWLINES $ 200	FENCING-PAINTING $ _____	VALVES-FITTINGS $ 200	
	FEATURE TOTAL	$ 4,500	$ _____
63 – SEPARATOR $ _____	HTR. TRTR. $ _____	DEHYDRATION EQUIP. $ _____	$ _____ $ _____
71 – METERING EQUIP. $ _____			$ _____ $ _____
72 – OTHER (ITEMIZE) Gas Package Unit			$ 7,500 $ _____
_____	TOTAL TANGIBLES		$ 96,800 $ _____

REMARKS

TOTAL ESTIMATE	$ 400,700	$ _____
LESS CONTRIBUTIONS	$ _____	$ _____
NET WELL COST	$ _____	$ _____
OUR NET COST	$ _____	$ _____

ORIGINATED BY _____ DATE _____ APPROVED _____ DATE _____

APPROVED _____ DATE _____ APPROVED _____ DATE _____

7209

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

March 12, 1982

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

Mr. Howard Kilchrist
Federal Energy Regulatory Comm.
Department of Energy
825 North Capitol Street, N.E.
Washington, D. C. 20426

Re: Tight Formation Designation
Order No. R-6888

Dear Mr. Kilchrist:

Enclosed please find the Recommendation and exhibits of the New Mexico Oil Conservation Division for designation of certain portions of the Mesaverde formation in San Juan County, New Mexico, as a tight formation.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr

enc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NGPA SECTION 107 TIGHT FORMATION RECOMMENDATION	)	Docket No._____
STATE OF NEW MEXICO OIL CONSERVATION DIVISION OF THE ENERGY AND MINERALS DEPARTMENT	)	

RECOMMENDATION FOR TIGHT FORMATION DESIGNATION UNDER SECTION 107 OF THE NGPA.

Koch Industries, Inc., pursuant to Section 107 of the Natural Gas Policy Act, 18 CFR §271.703 of the FERC regulations, and the Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 of the Oil Conservation Division, petitioned the Oil Conservation Division for tight formation designation of a portion of the Mesaverde formation in San Juan County, New Mexico.

After notice and hearing on the application of Koch Industries, Inc., the Oil Conservation Division hereby recommends that that portion of the Mesaverde formation which is described in Exhibit A (being Oil Conservation Division Order No. R-6888) attached hereto and incorporated by reference, be designated a tight formation. Additionally, the Oil Conservation Division, submits herewith Exhibits B, a copy of the exhibits presented to the Division, and C, a copy of a letter evidencing the concurrence of the Minerals Management Service, attached hereto and incorporated herein by reference, which are supporting data required under 18 CFR §271.703(c)(3) of the FERC regulations and Minerals Management Service ratification of this recommendation, respectively.

Respectfully submitted,

W. PERRY PEARCE
Attorney for the
Oil Conservation Division

VERIFICATION

STATE OF NEW MEXICO)
)ss.
COUNTY OF SANTA FE)

W. PERRY PEARCE, being first duly sworn, on oath, states that he is an attorney for the Oil Conservation Division of the Energy and Minerals Department of the State of New Mexico; that he has executed the foregoing document with full power and authority to do so; and that the matters and facts set forth therein are true to the best of his information, knowledge and belief.

W. PERRY PEARCE

Subscribed and sworn to before me, this 26th day of March, 1982.

NOTARY PUBLIC

My Commission Expires:

Oct 25, 1985

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Recommendation on Koch Industries, Inc., in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated this 26 day of February, 1982.

W. PERRY PEARCE

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

April 15, 1982

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

Mr. Howard Kilchrist
NGPA Compliance
Federal Energy Regulatory Commission
Department of Energy
825 North Capitol Street, N.E.
Washington, D. C. 20426

Re: Tight Formation
Designations

Dear Mr. Kilchrist:

At the request of members of your staff, I am enclosing copies of the transcript of hearing in Cases 7209, 7317 and 7361 before the New Mexico Oil Conservation Division. I will forward the transcript of Case 7395 shortly.

Please note that the transcript of Case 7361 incorporates the record from the Case 7116 examiner hearing. As you recall, the exhibits forwarded with the Division's recommendation in Case 7361 were the exhibits admitted in the examiner hearing of Case 7116. Therefore the transcript of Case 7361 is composed of two transcripts dated December 30, 1980 and September 29, 1981.

If we can be of further assistance, please advise.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr
enc.

DAVID D. FRIEND
CONSULTANT
RESERVOIR ENGINEER

2327 VENTOSO
WICHITA, KANSAS 67204

316-755-2586

United States Department of the Interior
OFFICE OF THE SECRETARY
Minerals Management Service
South Central Region
P. O. Box 26124
Albuquerque, New Mexico 87125

RECEIVED
MAR 03 1982
OIL CONSERVATION DIVISION
SANTA FE

MAR 02 1982

Mr. W. Perry Pearce
Oil Conservation Division
State of New Mexico
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Mr. Pearce:

This jurisdictional agency concurs in the recommendation of the State of New Mexico, Case No. 7209, Order No. R-6888, dated January 21, 1982, that the Mesaverde formation underlying the described lands in subject order in San Juan County, New Mexico, be designated as a Section 107 tight formation.

It is requested that this concurrence be included with the recommendation submitted to the Federal Energy Regulatory Commission.

Sincerely yours,

James W. Shelton
For Gene F. Daniel
Deputy Minerals Manager
Oil & Gas

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
25 March 1981

IN THE MATTER OF:

Application of Koch Industries, Inc. for designation of a tight formation, San Juan County, New Mexico.

CASE 7209

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:	Ernest L. Padilla, Esq. Legal Counsel to the Division State Land Office Bldg. Santa Fe, New Mexico 87501
For the Applicant:	William F. Carr, Esq. CAMPBELL, BYRD, & BLACK P.A. Jefferson Place Santa Fe, New Mexico 87501

I N D E X

RICHARD LUCE

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DAVID D. FRIEND

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MR. NUTTER: We'll call Case Number 7209.

MR. PADILLA: Application of Koch Industries, Inc., for designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, P. A., in Santa Fe, New Mexico, appearing on behalf of Koch Industries, Inc.

I have two witnesses who need to be sworn.

(Witnesses sworn.)

MR. CARR: I'll call Richard Luce.

RICHARD LUCE

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your full name and place of residence?

A. Richard M. Luce, 1 Park Central, Suite

530, Denver, Colorado.

Q. Mr. Luce, by whom are you employed and in what capacity?

A. Koch Exploration Company. I'm an exploration geologist.

Q. Will you briefly summarize your educational background and your work experience?

A. Yes. I graduated with a Bachelor of Science degree -- yes, a Bachelor of Science degree in 1976 in geological engineering from Michigan Technilogical University.

At that time I was employed by Tenneco Oil Company for a period of about two and a half years, during which time I was primarily in the capacity of a development geologist, working in the San Juan Basin area.

In January, 1979, I went to work for Koch Exploration Company as an exploration geologist and I've been working for them shortly over two years, working various areas in the Rocky Mountain Region, including the San Juan Basin.

Q. Are you familiar with the application which has been filed in this case?

A. Yes, I am.

Q. Are you familiar with the acreage which

is the subject of this application?

A. Yes, I am.

MR. CARR: Are the witness' qualifications acceptable?

MR. NUTTER: Yes, they are.

Q. Will you briefly state what Koch seeks with this application?

A. Koch is seeking a designation of the Mesaverde formation as a tight formation for an area in northern San Juan County, New Mexico, and includes the following lands: Township 32 North, Range 8 West, Section 7, 18, 19, 30, and 31; and Township 32 North, Range 9 West, Sections 10 to 15, inclusive; 22 to 27, inclusive; and 34 to 35, inclusive.

Q. Mr. Luce, have you prepared certain exhibits for introduction in this case?

A. Yes, I have.

Q. Have each of these exhibits previously been submitted to the Oil Conservation Division and to the United States Geological Survey, with a statement of the meaning and purpose of each, as required by Oil Conservation Division rules?

A. Yes.

Q. Will you please refer to what has been

marked for identification as Koch Exhibit One identify this, and explain to the Examiner what it shows?

A. Okay. Exhibit One is a structure map on the top of the green marker, which is approximately 350 feet above the top of the Cliffhouse member of the Mesaverde formation. It's persistent across the area.

The map shows a regional dip generally to the northeast at less than one-half degree. It also shows the land ownership for the -- the proposed tight formation area. This land includes 480 acres of fee acreage, 10,071 acres of Federal acreage, for a total of 10,551 acres in this proposed area.

Q. What are Koch's acreage holdings in this area?

A. Koch holds approximately 2336 acres in this area.

Q. And there are no State lands in the area for which you are seeking a designation.

A. That's correct.

Q. Would you now refer to Koch's Exhibit Number Two and review this for Mr. Nutter?

A. Okay. Exhibit Number Two is hanging up there on the wall, Mr. Nutter. It's a type log in the Mesaverde formation. I believe it's designated as a type log

on the Exhibit Number One in the Section 26 of 32 North, 9 West.

This exhibit shows the interval from the green marker datum contoured on Exhibit One and also includes the Cliffhouse, Menefee, and Point Lookout members of the Mesaverde formation.

The vertical limits of the Blanco-Mesaverde Pool have been defined by the New Mexico Oil Conservation Division in this area as extending from the Huerfanito Bentonite in the Lewis Shale to a point 500 feet below the top of the Point Lookout member.

The H uerfanito Bentonite on this type log exists about 816 feet above the green marker.

The CliffHouse and Point Lookout members are considered the main producing zones of this field but less continuous sands of the Menefee also contribute to the overall production of the Mesaverde in this area.

In the proposed tight gas sand area the Cliff House averages only about 50 feet thick and the porosity ranges from less than four percent to fifteen percent.

The Menefee in this area ranges from 230 to 290 feet thick and the porosity varies from less than three percent to about seventeen percent.

The lower member of the Point Lookout

sands are about 150 to 200 feet thick in this area and there are also significant stringers of sand that may be seen as low as 300 feet or so below the top of that Point Lookout member.

The porosity in this Point Lookout type -- or the porosity in the Point Lookout in the type log ranges from about three percent to fourteen percent and is considered typical of the porosity in this area.

The average porosity for these sands of all three members is about eight percent.

Q. Mr. Luce, will you now refer to Koch Exhibits Three and Four and review these for Mr. Nutter?

A. Exhibits Three and Four are west/east and southwest/northeast stratigraphic cross sections through this area. The datum for these cross sections is the green marker. They show the continuity of the Cliff House and the Point Lookout sands across this area, and what also can be seen from these two cross sections is the irregularity of the sands in the Menefee.

The Point Lookout consists of near shore or shoreline sands deposited during an overall regression of the Mancos Sea. The sand buildups in this area represent periods of still stand during that regression. The sands have been described as light gray, very fine to fine grain,

well cemented, argillaceous matrix, with poor visible porosity.

The Menefee represents a period of non-marine deposition during Mesaverde time. Environments of deposition include coal-forming swamps and coastal plain deposits. Numerous coals, silts, and shales, and channel sands can be observed in a typical Menefee section. Reservoir quality often is similar to that of the Cliff House and Point Lookout sands but the continuity and predictability of these sands is very poor.

Binocular description of the sands is not appreciably different than that description of the Point Lookout sands.

Finally, the Cliff House consists of a widespread shoreline sand deposited during transgression of the Lewis Sea. These sand buildups represent stillstands during that transgression.

Again, binocular description of these sands is very similar to that of Point Lookout and the Menefee members.

The Cliff House in the proposed area is nearly to the point where it's pinched out completely and there's only about -- there's only fifty feet of total interval and about ten feet of that is potentially productive. The gross interval of the Menefee contains an average of only two

to three benches of productive, potentially productive sands, whereas to the south the wells have Menefee sections of greater than 1000 feet with several potentially productive benches.

The Point Lookout in this area is also near its seaward edge of -- of its seaward productive limit. The overall -- overall the area is near the productive limit of the various members of the Mesaverde with relatively few objective zones in this area. We view the risk of drilling an uneconomic well is considerably greater than even a few miles to the south.

Q. Mr. Luce, does the Mesaverde formation underlie all the acreage for which you are requesting a tight formation designation?

A. Yes, it does.

Q. And in your opinion is the formation productive throughout the area?

A. Yes, it is.

Q. What is the average depth from the surface to the top of the Mesaverde formation?

A. It's approximately 4200 feet.

Q. Were Exhibits One through Four either prepared by you or under your direction and supervision?

A. Yes, they were.

MR. CARR: At this time, Mr. Nutter, we

would offer into evidence Koch Exhibits One through Four.

MR. NUTTER: Exhibits One through Four will be admitted in evidence.

MR. CARR: I have nothing further of this witness on direct.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Luce, now your Exhibit Number One indicates that there's a total of 10,551 acres in the area under consideration. That is the area that's outlined by the little hachured line, that --

A. Yes, sir, that's correct.

Q. Okay. Now, in that area there are 480 fee acres. Would you identify the fee acres, please?

A. Yes, those are outlined by the dash-dot type of pattern. There -- there's 160 acres in Section 14 of 32 North, 9 West; a 40-acre tract in the southwest southwest of Section 22, 32 North, 9 West; and about 280 acres in Section 27 of 32 North, 9 West.

Q. Now there have been wells drilled in the total 10,551 acres, have there not --

A. Yes, sir, that's correct.

Q. -- that penetrated the Mesaverde.

A. That's correct.

Q. How many Mesaverde wells are in here?

A. Fourteen wells.

Q. And this Exhibit Number Two, which is the log of the Gardner No. 5, is this a typical log for all of the wells that have been drilled in the area?

A. Yes, sir, we believe that it's fairly representative of the wells in this area.

Q. Now you talked about the first -- the porosity of the area but you didn't get into permeability, is that right?

A. The permeability will be discussed by our reservoir engineer.

Q. I see.

MR. NUTTER: Are there any further questions of Mr. Luce? He may be excused.

MR. CARR: I'll call David Friend.

DAVID D. FRIEND

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your full name and place of residence?

A. David D. Friend, 2327 Ventoso, Wichita, Kansas, 67204.

Q. Mr. Friend, by whom are you employed and in what capacity?

A. I am self-employed as a consulting engineer. Koch Industries has employed me to prepare data for this hearing.

Q. Have you previously testified before this Commission or one of its examiners?

A. No, I have not.

Q. Will you summarize for Mr. Nutter your educational background and your work experience?

A. I received both Bachelor of Science and Master of Science degrees from the Missouri School of Mines. I received the Master of Science degree in 1961.

I joined Texaco in south Lousiana and worked as a field engineer and reservoir engineer until January of 1968.

In January of 1968 I joined Hunt Oil Company as Project Engineer at the Fairway ~~Miscible~~ Miscible Gas and Water Injection Project, East Texas.

In August of 1969 I joined CORE Labor-

atories engineering and consulting group and worked with them as a consulting engineer on projects both in the United States and foreign.

In April of 1974 I joined Tesoro Petroleum Corporation and was moved into the position of Chief Reservoir Engineer, responsible for domestic and part of their foreign work.

In August of 1978 I joined Koch Exploration. One of my duties with Koch Exploration was development drilling of San Juan Basin.

In August of 1980 I resigned from Koch and have worked as an independent consulting engineer.

MR. NUTTER: How do you spell your last name, please?

A. F-R-I-E-N-D.

MR. NUTTER: Thank you.

Q. Are you familiar with the application which was filed for Koch in this case?

A. Yes, I am.

Q. Are you familiar with the subject area?

A. Yes, I am.

Q. Have you prepared certain exhibits for introduction in this case?

A. Yes, I have.

Q. Have each of these exhibits previously been submitted to the USGS and the OCD, as required by Division rules?

A. They have.

Q. Will you please refer to what has been marked for identification as Koch Exhibit Number Five, and review this for Mr. Nutter?

A. Before we get into Exhibit Number Five, I would like to comment, we have reviewed State and Federal regulations concerning protection of fresh water.

Exhibit Number Five presents a schematic of the typical well completion for Koch-operated wells. The completion procedure is in line with State and Federal regulations which require that casing programs be designed to seal off potential water-bearing formations, thus separating them from oil and gas-bearing formations.

The illustration shows that 14-3/4 inch hole is drilled to approximately 200 feet; 10-3/4 inch casing is cemented in place with the cement being circulated to surface.

An 8-3/4 inch hole is drilled to approximately 3500 feet and 7-inch casing set with cement again being circulated to the surface; a 6-1/4th inch hole is gas drilled to total depth and 4-1/2 inch casing set and cemented

with enough cement to extend up into the 7-inch casing.

A temperature survey is run to determine the top of the cement in the production string.

The base of the Ojo Alamo is shown on the exhibit as being at 2185 feet. Fresh water aquifers extend from the surface to the base of the Ojo Alamo; a distance of approximately 4000 feet separates the normal perforated Mesaverde interval and the base of the fresh water aquifer. The chance of a frac flood or gas being communicated with fresh water over this long interval is, well, it just should not happen. It should not be communicated.

In the event that there is communication behind pipe, Koch would squeeze the channel, perform whatever remedial work is required to isolate the intervals.

The upper 3500 feet of the well is drilled with native mud which will not contaminate fresh water zones. During well completion operations the three zones are individually broke down with approximately 500 gallons of 7-1/2 percent acid prior to fracing. It is my opinion that this acid will not contaminate an extensive aquifer.

The frac fluid used consists of fresh water with approximately 2 percent KCL added, and again, this fluid would not contaminate an extensive aquifer.

Q. If you experience a leak during the life of this well, would you anticipate that the waters in the area would be contaminated with fluids from the well or would it work so that the fluids migrated into the wellbore?

A. The water would migrate into the wellbore and down into the gas zone.

Q. Now, do these fresh water zones exist throughout the area?

A. I believe that they do.

Q. I believe you stated that you'd reviewed applicable State and Federal regulations.

A. Yes, I have.

Q. In your opinion will compliance with these regulations assure that the development of the portion of the Mesaverde formation which is the subject of this hearing not adversely affect or impair any fresh water aquifers during any fracturing or waste disposal operations which you now use or could anticipate using?

A. No, it will not, and I believe that this is the best effort I have seen in any area, where people have tried to protect the fresh water sands.

Q. Is it your testimony that the proposed development of the subject area will not affect either domestic or agricultural water supplies?

A. Yes, sir, it is.

Q. All right, Mr. Friend, will you now refer to what has been marked as Koch Exhibit Number Six and review this for Mr. Nutter?

Exhibit Six is located in the folder behind the summary. In the lefthand side of the folder is first a summary, then a list of these exhibits with a statement of the meaning of each, and then behind that should be the remaining exhibits.

MR. NUTTER: What does Six look like?

A. It's a table.

MR. CARR: That's Exhibit Number Seven, now, DAvid.

A. Okay. Number Six is our tight sands production map. I'm sorry.

MR. CARR: The exhibits in that folder start with Exhibit Seven. We have a plat which is Exhibit Six.

A. Exhibit Number Six is a production map of the tight formation area, and many of the surrounding wells; anticipated is all the production expected from Koch operated wells as determined by Ryder Scott Petroleum Engineers, a consulting company that Koch uses to determine their reserves, as shown from the Koch wells.

The map shows at the south and the west the cumulative gas production from the wells has been more than in a tight formation area.

Q. Will you now refer to your Exhibit Number Seven and review this for Mr. Nutter?

A. Exhibit Number Seven lists the wells in the tight sand area which are operated by companies other than Koch. These wells were drilled --

MR. NUTTER: Just a minute, please. Thank you.

A. Exhibit Number Seven shows wells in the tight sand area which are operated by companies other than Koch. These wells were drilled prior to 1960 and all wells were stimulated. No pre-stimulation rates were reported and the post stimulation rates range from an IP of 145 Mcf per day to 3483 Mcf per day absolute open flow.

Q. Mr. Friend, will you now review Exhibit Number Eight?

A. Exhibit Number Eight lists the Koch operated wells in the tight formation area.

The first well was drilled in 1954. No additional wells were drilled until 1976. The results of the wells drilled in 1976 were disappointing and development was suspended until 1980, when two additional step-out wells

and one infill well was drilled.

Koch has again stopped drilling due to poor economics. As many as seven or eight additional wells can be drilled on the Koch acreage alone if the economics are more favorable.

The only Koch operated well producing measureable gas prior to stimulation was Gardner No. 1. The details of this test are not known. It is doubtful that this represents a stabilized flow rate.

All the wells were drilled with gas, which provided a continuous test. Gardner Well No. 4 was the only well with a slight show of gas while drilling. Gardner Well No. 5 produced at a rate too small to measure prior to stimulation.

Various types of well completions have been tried by Koch in an attempt to increase gas production. Each interval shown on the exhibit has been frac treated alone.

The number of intervals has been varied from two to three. Total frac treatments range in size from 80,000 pounds to a massive 293,000 pounds. The post-stimulation flow rates shown on the exhibit should not be considered as representative of a well's long term ability to produce. Producing rates show a rapid decline following initial potential.

The most recent wells drilled are Gardner No. 4-A and No. 5. The respective drilling and completion costs were $489,000 and $407,000 for these wells.

MR. NUTTER: Give me those figures again, please.

A. Okay. For Well 4-A it was $489,000. For Well No. 5 it was $407,000.

MR. NUTTER: $470,000?

A. $407,000.

MR. NUTTER: $407,000. Mr. Friend, do you have any idea what percentage or what amount of that total cost was for stimulation?

A. For Well 4-A Koch paid $67,000 to the treating company.

For Well No. 5 Koch paid $74,000.

MR. NUTTER: Thank you.

A. And that does not include rig time or other related expenses.

Q. Mr. Friend, have you been able to establish pre-stimulation permeability?

A. In an area with a very low permeability such as this has it is very difficult to run the standard build up test prior to stimulation. It is very difficult to determine permeability by the standard means.

We have used two methods here in an attempt to approximate permeability and to get a reasonable feel for -- for the value.

Q. Have any of the wells been cored?

A. None of the wells have been cored.

Q. Have you attempted to calculate the pre-stimulation flow rates?

A. One pre-stimulation flow rate was available and that was from Gardner Well No. 1 and as mentioned before, the test data is not well documented, so certain assumptions are necessary to perform calculations to determine permeability based on the reported rate of ~~407~~ 47 Mcf per day.

First, it was assumed that this was a stable rate, and it was also assumed that the flowing wellhead pressure was at or near atmospheric pressure.

A porosity log was not run on this well; therefor, the net pay of 149 feet, based on Gardner Well No. 5, was assigned to part of these calculations.

Exhibit Number Nine presents the calculations used to determine the permeability. The results show a permeability of .0208 millidarcies, and this is probably high. As I mentioned, the flow rate might not have been stable.

Q. And this rate was calculated using

Darcy's law, is that correct?

A. Yes, it was based on Darcy's law.

Q. What other efforts did you undertake to calculate permeability?

A. We used actual test data from Gardner Well No. 3 and a computer program designed to calculate permeability based on performance.

The basis for the analysis for this paper is by Gringarten, Ramey, and Raghavan, which was published in Volume 257 of the AIME Transactions. Solution of the problem was made possible by the use of the Garrett Computing System, their program gas well performance simulation. The Garrett System is obtaining nationwide use in the industry.

Q. Are copies of that report included with the material that has been supplied to the Commission?

A. Copies of the report was -- was included.

Exhibit Number Ten presents the data input to calculate the porosity -- the permeability from Gardner No. 1 -- No. 3, I'm sorry. The porosity used was 11.7 percent with a net pay of approximately 250 feet; liquid saturation 55 percent; reservoir pressure of 150 degrees Fahrenheit; and a drainage area of 160 acres was used.

The test data and the date of the test is shown on the exhibit and the flow rates also indicate the

rapid decline of the well's potential after it has been put on.

The calculated permeability based on different fracture lengths to match the history, are shown as the results in Exhibit Number Ten. It can be seen that the last slope here where the rate was 115 Mcf per day, that a reasonable match is obtained with a permeability of .00122 to .0125, 126, millidarcies.

The basic assumptions in the computer program include a single, uniform interval in a homogeneous reservoir, and the Mesaverde does not meet this requirement, and since more -- since each zone is fraced separately, we did not have a single uniform fracture exist in the well. We would contend that the well is producing as though it were a homogeneous reservoir with a permeability of about .0012 or .0013 millidarcies permeability.

Q. Mr. Friend, in your opinion, based on the data that is available to you on this formation, is the permeability throughout this area less than one-tenth millidarcy per foot?

A. Yes, it is.

Q. Will you please refer now to what has been marked for identification as Koch Exhibit Number Eleven?

A. Exhibit Number Eleven shows the completion

date, cumulative production, and current status of wells completed in the Mesaverde formation in the proposed tight formation area. The remaining reserves as determined by Ryder Scott Engineers are included for the Koch operated wells. Comparison of the completion data and the current status shows the -- again shows the rapid early production decline experienced in Gardner Wells 2, 3, 3-A, and 4.

Q. Mr. Friend, will you now review Exhibit Number Twelve for Mr. Nutter?

A. Exhibit Number Twelve is a cost estimate to drill and complete the wells to the Mesaverde formation tight sand area. You'll notice the total cost of the estimate is $400,700, which is actually less than the last two wells cost, and this is assuming a completely trouble-free well.

Q. Will you now refer to Exhibit Number Thirteen?

A. Exhibit Number Thirteen presents an economic analysis for a well drilled in the tight gas formation area. Production data used for the projection was taken from the first twenty-five years of history from the Gardner Well No. 1. The assumptions used in the economic analysis are shown on the first page of the exhibit.

The exhibit also presents the results

of analysis that would show that a discounted flow rate of return is 7 percent with a payout period of 9.4 years before income tax. These values are reduced to 6 percent rate of return with a 10.4 year payout after income tax.

Pages two and three of the -- are the computer printout for this case.

Section 107 tight gas formation prices were also used to determine payout and rate of return. In this case the after tax rate of return will be twenty percent and the payout will be four years, neither of which is excessive but they should be acceptable.

MR. NUTTER: Is that given on one of the exhibits?

A. No, it is not shown on an exhibit.

Q. Mr. Friend, in looking at this Exhibit Thirteen, the figures that you've used appear to assume that no drilling difficulties or risks are included or incurred.

A. That is correct. This is the minimum drilling and completion costs.

Q. How would this affect the actual parameters for these figures?

A. They're just cost of drilling, and as I menticned before, one of the last wells drilled did cost considerably more than the $400,000. The rate of return is

even more; payout is extended.

Q. Is it fair to assume that the actual parameters would be less attractive than those you have shown?

A. Yes.

Q. Is the 107 price necessary to provide a reasonable incentive for production of natural gas from the formation, due to the extraordinary risks and costs associated with such production?

A. Yes, Section 107 tight gas formation prices will provide a more favorable economics and will result in additional development in the area. It is very doubtful that Koch would drill any additional wells in the area in the near future without an increase in gas price, and under existing economic conditions they have stated they will not drill additional wells.

Q. Has this area been designated as an area that can be developed with an infill drilling program?

A. Yes, it has.

Q. Would the statement which you have made concerning Koch's unwillingness to drill additional wells in this area due to economic considerations also apply to the infill wells?

A. Yes, it would.

Q. Will you now review your Exhibit Number

Fourteen for Mr. Nutter?

A. Exhibit Number Fourteen presents a summary of pertinent reservoir data for the Mesaverde formation in the tight gas area.

The average porosity is about 11.3 percent, based on a porosity cutoff of 8 percent. This is not the same porosity value which was mentioned earlier; however, the lower porosity given by Mr. Luce uses a much lower porosity cutoff and we feel that the 8 percent, while it might not include all gas which is produced, it will include most of the gas that is produced.

A definite permeability was not established; however, the permeability which is shown is less than .02 millidarcies and certainly it's less than .1 millidarcies.

The original reservoir pressure is 1177 pounds. The reservoir temperature of 150 degrees. The average net pay from Koch's wells is 156 feet and there is no oil production from any of the wells in the tight area -- tight formation area.

Q. Mr. Friend, could you summarize the conclusions you can -- you have reached as a result of this study?

A. The Mesaverde formation in the proposed area meets the guidelines necessary to qualify the area for

tight formation designation.

These are, the in situ permeability is less than .1 millidarcy; the stabilized gas production rate is less than 163 Mcf maximum permitted for wells completed below 5000 feet. No well will produce more than 5 barrels of oil per day. The fresh water sands in the area will be adequately protected during drilling and completion and production operations.

In addition, wells completed in the area will show favorable economics based on an incentive 107 price; based on the existing gas price the economics are unfavorable.

Q. Mr. Friend, concerning your statement relating to the production of less than 5 barrels of crude oil per day, do these wells produce any fluid at all?

A. They do not produce any oil at all.

Q. Do they produce any condensate?

A. No, they do not.

Q. Were Exhibits Five through Fourteen prepared by you or under your direction and supervision?

A. Yes, they were.

Q. In your opinion will granting this application be in the best interest of conservation and prevention of waste, and the protection of correlative rights?

A. Yes, it will.

MR. CARR: At this time, Mr. Nutter, we would offer into evidence Koch Exhibits Five through Fourteen.

MR. NUTTER: Exhibits Five through Fourteen will be admitted in evidence.

MR. CARR: I have nothing further of Mr. Friend on direct.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Friend, first of all, on your Exhibit Number Six you've got the area as outlined, or the area that's under consideration outlined there, and to the east I see an area that says San Juan 32-8 units; to the west I see San Juan 32-9 units.

A. Yes, sir.

Q. Are these lands that are under consideration in either of those units or are they lands that lie between the two units?

A. The Koch acreage could be included in there, should be included in 32-9 unit area.

Q. Which is the Koch acreage?

A. That's the acreage which is shown in the hachured part of the map.

Q. Okay, that's in Section 25, 26, part of 27, 35, and 31 in the next township over.

A. Yes, yes, it is.

Q. Okay, and El Paso and Northwest operate these other wells, or own the other lands, is that it?

A. Yes. There are other operators in the general area but most of the wells are operated by El Paso and Northwest.

Q. Now what was the basis for determining that this particular area that you've outlined here would be the area for study of the tight sand?

A. The northern area that was picked as the Colorado border.

Q. Okay.

A. Section 36 was not included because it is now fully developed.

The other acreage, other than Koch's, was included to square up the area and to give an area which other operators could easily identify to in the event that they want to submit their own tight formation hearing.

Q. Naturally what you were interested in is designation of the Koch acreage.

A. That is right.

Q. And does Koch own Section 36?

A. No, they do not. It's part of the San Juan 32-9 unit.

Q. Now it looks like Section 31 already has one -- it's fully developed with one infill well already drilled, is that right?

A. There is one more well.

Q. Uh-huh.

A. Yeah, the second infill well.

Q. Now these cumulative productions that are given as zero, that means the well has not gone on the line yet?

A. It was not on line October 31st of 1980.

Q. And what are the estimated ultimate productions based on for these wells?

A. Those are -- for the Koch wells it's based on the Ryder Scott estimate. Ryder Scott is a consulting company in Houston.

Q. Okay, and I believe the actual figures were included on some exhibit there, weren't they?

A. Yes, they are.

Q. Now, on these economics you have taken a well on your Exhibit Number Thirteen, and is this a well or this a hypothetical well?

A. That is actual production data from

Gardner Well No. 1.

Q. Which was completed back in 1954.

A. Yes, that's the first twenty-five years of production from that well.

Q. And the data from that well is punched out on the computer on page two of Exhibit Three, isn't it?

A. Yes, Exhibit Thirteen.

Q. So you show that the well is producing gas at $2.39 a barrel --

A. Right.

Q. -- in Mcf. That well hasn't produced $2.39 gas since 1954 by any means, has it?

A. No, this is based on the assumption that a well would now produce at $2.38.

Q. Right. So you're taking present day economics and applying it to an old well's production history.

A. Yes, we are.

Q. Now is this operating cost of $4800 a month typical of Koch's operating costs up there?

A. I'm afraid it will be. Some of the wells are producing some water. They're having to run small tubing in the wells. They do have to occasionally swab the wells in. This is not an easy area to operate in.

Q. I see. So these aren't gas wells you

can just go turn on and forget.

A. No, they're not.

Q. And you calculate, based on the history from Gardner No. 1, and that's the only old well that Koch operates in the area --

A. Yes.

Q. -- you calculate that based on today's economics, without the tight sand incentive price, in other words a gas price of $2.39 an Mcf, that before income tax it will take 9.4 years to get a payout.

A. Yes, sir.

Q. And after income tax, 10.4 years.

A. Yes.

Q. And this gives you a discounted cash flow rate of return of 6 percent.

A. Yes, after income tax.

Q. Now you said no cores have been taken in the area?

A. Not in the area that we are considering here.

Q. Now you had an exhibit -- I can't find it right now -- where you took this pre-stimulation flow rate of 47 Mcf from that one well and used it for calculating permeability. What exhibit was that, Mr. Friend?

A. That was Number Nine, I believe.

Q. Now you stated -- this well did actually flow 47 Mcf per day against an atmospheric pressure, assumed atmospheric pressure, but when you first went over this data you mentioned you didn't think it was stabilized flow rate. Do you think a stabilized flow rate would have been lower than that?

A. Much lower. I'm not at all certain these wells will flow at all at a stable rate.

Q. So on your Exhibit Number Nine you gave the well the benefit of the doubt.

A. Yes.

Q. And said, now it made 47 Mcf on a puff here when it was first completed and you're going to assume it will continue puffing at that rate.

A. That's right.

Q. And you calculated a permeability then of .02ths of a millidarcy.

A. Yes.

Q. Now what about Section 3 to the south of your area here, Mr. Friend? I don't see any wells in there at all.

A. No, there are none.

Q. And there is a well in Section 2 in the

northwest quarter which has no history. What's -- what's the characteristic of that well?

A. It is a new well.

Q. I see.

A. We did check with Aztec to make certain that no wells had been drilled in 3 and they confirmed that there are none.

Q. You stated that the better part of the Mesaverde is to the south and to the west here.

A. Yes.

MR. NUTTER: Are there any further questions of Mr. Friend? Yes, sir.

MR. HIGGINS: My name is Robert Higgins. I'm with the U. S. Geological Survey in Albuquerque, and we reviewed this and basically have no problems. I just want to bring up the issue of some of the boundary criteria in this case.

It appears that the boundary here is based on lease lines, the section boundary, is that correct?

A. That is correct.

MR. HIGGINS: What we're interested in is if there's any physical criteria that we could demarcate these areas of tight -- where the tight formation is between the good producing trends and the tight gas is, so that we

can -- it's tied into either production of wells or geologic, either stratigraphic or the geometry of the thing, or something of that nature so you could get large amounts of acreage that is based on something that's physical rather than just seeing a lot of these cases, tight gas cases, that just crop up depending on who is the owner, if there would be some way to get together and have large acreages designated that all have similar characteristics, whether physically measured or mapped or something else.

So, I know that's difficult;in some cases impossible task, but as a regulatory agency it makes our task simplier than looking at ten cases and seeing tight gas intervals.

You could identify trends for us. This is a good producing trend and the poor producing trend begins here, so that is the tight gas area. It's just an issue at the Survey that we thought we should bring forth because a lot of these cases are being brought up and they seem to be all tied into just who owns what acreage rather than something that is geologic or engineering trends.

A. In reviewing the electric logs between Koch's wells in the tight formation area and some of the other better wells, there was no apparent difference between these at all.

Now many of the older wells do not have our modern suite of logs. They have neutron or just an electric log in some cases.

But there we did not find an apparent change in formation characteristics between the two; just the permeability deteriorates in the tight formation area here.

MR. HIGGINS: And this case per se is not based on geologic trends?

A. No, not at all.

MR. NUTTER: I think Mr. Friend answered awhile ago, he said that they put Koch's acreage under study and then squared it off.

A. That's correct.

MR. NUTTER: And kicked one section out because it was fully developed, and extended it north to the Colorado line to square it off.

But there's no -- there's no suggestion that this is any geological line or engineering parameters change, or anything like that; just the area you chose to study.

A. That's right.

MR. NUTTER: You don't have a tight sand down here in this well in the southwest quarter of Section 12, I don't think, do you?

The one with the 7-billion cumulative?

A. There might be a fracture there, a natural fracture.

MR. NUTTER: Are there any further questions of Mr. Friend?

MR. CHAVEZ: Yes, I'd like to ask a question.

MR. NUTTER: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Friend, the stimulation treatments that you put on these wells, do you have any estimate as to what the effective increase in permeability would be with the stimulation you put on the wells?

A. We did run a post-stimulation build-up test on one well. We got a permeability of .18 millidarcies. That was on the Gardner No. 3. It is the same well that we feel had a pre-stimulation permeability of .0012, or something in that range.

Q. Well, didn't the expected increase, did it come from this stimulation of the well?

A. I believe it is.

Q. The data that you used on your calculation of permeability, let's see, you used the Exhibit Seven --

you used the thickness, let's see, you ran it on the production of the Gardner 1; you used the formation thickness from the Gardner 3?

A. Yes, because we did not have a density log or any type of porosity log for the Gardner No. 1, and we could not pick porosity or net pay, so we used the closest offset.

Q. Yeah, but you had a perforated interval, didn't you?

A. It was completed open hole.

Q. Oh, completed open hole?

A. Yes, sir.

Q. Okay.

MR. CHAVEZ: That's all.

MR. NUTTER: Are there any other questions? Mr. Friend may be excused.

Do you have anything further, Mr. Carr?

MR. CARR: Nothing, Mr. Nutter.

MR. NUTTER: Does anyone have anything they wish to offer in case Number 7209?

We'll take the case under advisement and the hearing is adjourned.

(Hearing concluded.)

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd C.S.R.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7601 heard by me on 3/25 19 81.

, Examiner
Oil Conservation Division

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 7209
Order No. R-6888

APPLICATION OF KOCH INDUSTRIES, INC. FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on March 25, 1981, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this 21st day of January, 1982, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Koch Industries, Inc., pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, requested the designation as a "tight formation" of the Mesaverde formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM
Section 7: All
Sections 18 and 19: All
Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM
Sections 10 through 15: All
Sections 22 through 27: All
Sections 34 and 35: All

containing a total of 10,551.0 acres, more or less.

(3) That the vertical limits of the Blanco-Mesaverde Pool in the area under consideration extend from the Huerfanito Bentonite in the Lewis Shale to a point 500 feet below the top of the Point Lookout member of the Mesaverde formation and consist of the Cliffhouse, Menefee, and Point Lookout members, with the Cliffhouse and Point Lookout zones contributing most of the gas, and the less continuous Menefee sands also contributing in some wells.

(4) That in the area under consideration, the thickness and porosity of the three zones is as follows: Cliffhouse, average thickness about 50 feet, porosity range from four to 15 percent; Menefee, thickness range from 230 feet to 290 feet, porosity range from less than three percent to 17 percent; and Point Lookout, thickness range from 150 feet to 200 feet, porosity range from three percent to 14 percent. The average porosity for all sands in all three members is approximately eight percent.

(5) That the aforesaid three members of the Mesaverde group exhibit depositional characteristics of three distinct phases -- shoreline deposits during the regression of the Mancos Sea, non-marine deposits of coals, silts, and shales, and shoreline deposits during transgression of the Lewis Sea -- and overall combine to form a low permeability pay near the northern productive limits of the Blanco Mesaverde Pool.

(6) That the average depth from the surface to the top of the Cliffhouse formation of the Mesaverde group in the area under consideration is approximately 5463 feet.

(7) That there have been 14 Mesaverde wells drilled in the area under consideration; that the expected ultimate recovery from these wells ranges from two million cubic feet of gas to 787 million cubic feet, and averages 374 million cubic feet.

(8) That development in the area to date consists of two sub-areas, with five of the 14 wells drilled to date being in the northern portion of the overall area, and nine of the 14 wells drilled to date being in the southern portion of the overall area.

(9) That the expected ultimate recovery for the five wells in the northern sub-area ranges from two million cubic feet of gas to 787 million cubic feet and averages 254 million cubic feet, while the expected ultimate recovery from the nine wells in the southern sub-area ranges from two million cubic

feet of gas to 596 million cubic feet and averages 440 million cubic feet.

(10) That data are not available in this case to determine the in situ gas permeability of the Mesaverde formation in the northern sub-area under consideration in this case.

(11) That the data available to determine the in situ gas permeability in the southern sub-area in this case is sketchy, based upon applicant's Exhibits 9 and 10. That Exhibit 9 indicates an in situ permeability in applicant's Gardner Well No. 1, located in Unit M of Section 35, Township 32 North, Range 9 West, NMPM of 0.0208 md.

(12) That while Exhibit 10 purports to show an in situ permeability for applicant's Gardner Well No. 3, located in Unit N of Section 31, Township 32 North, Range 8 West, NMPM, equivalent to 0.0012 or 0.0013 md, it is believed that the permeability calculations discussed in Finding No. (11) are based on more accurate input data and assumptions, and more nearly reflect the true in situ permeability of the Mesaverde formation in the southern sub-area, and although Exhibit No. 10 should be disregarded, it is reasonable to assume that the in situ permeability of the Mesaverde formation in the southern sub-area is less than 0.1 md.

(13) That no pre-stimulation stabilized flow rates are available for any of the 14 wells drilled in the area under consideration, but that data indicating the capability of the formation to produce, without stimulation, is available for wells drilled in the southern sub-area as follows:

A. A non-stabilized flow rate of 47 MCF per day against atmospheric pressure was obtained on the Gardner Well No. 1 when it was drilled in 1954. A stabilized rate of production would have been less than 47 MCF per day.

B. Gardner Wells Nos. 2, 3, 3-A, 4, 4-A, and 5 were drilled with gas so that a continuous check was possible as to whether the formation was producing during drilling operations. Gardner Wells Nos. 2, 3, 3-A, 4-A, and one zone of 5 indicated "no gas while drilling." Gardner Well No. 4 indicated "slight show of gas while drilling," and one zone of Well No. 5 indicated that gas "too small to measure" was produced during drilling operations.

(14) That based upon the evidence discussed in Finding No. (13) above, it may reasonably be assumed that the stabilized productivity, prior to stimulation, of the wells completed in the Mesaverde formation in the southern sub-area is less than the 163 MCF per day which is the maximum productivity set forth in 18 C.F.R. 271.703(c)(2)(i)(B) for wells in the 5000-5500 foot range.

(15) That no data is available in this case to demonstrate the before-stimulation productivity of wells in the northern sub-area under consideration.

(16) That none of the wells drilled in the area is capable of producing, with or without stimulation, more than five barrels of oil per day.

(17) That there are fresh water aquifers in the area under consideration extending from the surface to the base of the Ojo Alamo formation, which is found at an average depth of approximately 2185 feet; that an average of some 3278 feet of vertical distance separates the base of said Ojo Alamo and the top of the Cliffhouse member of the Mesaverde formation.

(18) That the state and federal regulations governing casing and cementing of wellbores, as well as the aforementioned vertical distances, should prevent any adverse impact upon the fresh water aquifers during both hydraulic fracturing and waste disposal operations.

(19) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(20) That the Division, by its Order No. R-1670-T dated November 14, 1974, approved infill drilling in the Blanco Mesaverde Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Mesaverde formation underlying the lands described in Finding No. (2) above and under consideration in this case.

(21) That it appearing to the examiner at the hearing of this case on March 25, 1981, that there was insufficient evidence to make the determination described in Finding No. (19)

above, i.e., that the formation could or could not be developed economically absent the tight formation incentive price, the applicant was asked to submit additional evidence regarding well development and operating costs, reserves, and rates of return on investment under normal Section 103 gas prices and under Section 107 gas prices.

(22) That the requested data was submitted in the form of Revised Exhibits 6 and 13 in this case, and the original Exhibits 6 and 13 should be disregarded.

(23) That the data submitted by applicant on Revised Exhibit 13 in this case relates to reserves, development and operating costs, and rates of return in the southern sub-area only, and no data are available pertaining to such matters for wells drilled in the northern sub-area.

(24) That according to Revised Exhibit 13, the average ultimate recovery which may be expected under the Section 103 gas price in Sections 25, 26, 27, and 35, Township 32 North, Range 9 West, NMPM, and Section 31, Township 32 North, Range 8 West, NMPM, is approximately 494 million cubic feet of gas; that with development costs of approximately $400,700 per well and operating costs of approximately $4800 per year per well, the gross revenue received less expense interest and royalty interest and severance and ad valorem taxes, the operator may expect an 8.8 percent rate of return before income taxes on his investment, or 7.3 percent rate of return after income taxes.

(25) That according to Revised Exhibit 13, the average ultimate recovery which may be expected in the same area and under the same conditions as described in Finding No. (24) above, except under the Section 107 incentive gas price, is some 516 million cubic feet of gas, and the operator may expect a 39.2 percent rate of return on his investment before income taxes, or 27.5 percent rate of return after income taxes.

(26) That while the 39.2 percent rate of return before taxes or 27.5 percent rate of return after taxes provided by the incentive price may seem excessive, it is obvious that the 8.8 percent rate of return before taxes or 7.3 percent rate of return after taxes under the Section 103 price is too low to justify the risk of drilling additional wells in the area.

(27) That inasmuch as there is no data as to pre-stimulation flow rates in the northern sub-area, nor is there any data relating to development and operating costs vs. revenues, and rates of return, no recommendation as to designation of tight formation should be made at this time for that area.

(28) That the data that is available in this case justifies the recommendation as a tight formation in the southern sub-area, and that area should be described as follows:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM
Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM
Sections 25 through 27: All
Sections 34 and 35: All

containing a total of 4216.98 acres, more or less.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Mesaverde producing interval extending from the Huerfanito Bentonite in the Lewis shale to a point 500 feet below the top of the Point Lookout member of the Mesaverde group, and consisting of the Cliffhouse, Menefee, and Point Lookout members of the Mesaverde group, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM
Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM
Sections 25 through 27: All
Sections 34 and 35: All

containing a total of some 4216.98 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (2) of this order but not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY,
Director

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
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January 22, 1982

Mr. William F. Carr
Campbell, Byrd & Black
Attorneys at Law
Post Office Box 2208
Santa Fe, New Mexico

Re: CASE NO. 7209
ORDER NO. R-6888

Applicant:

Koch Industries, Inc.

Dear Sir:

Enclosed herewith are two copies of the above-referenced Division order recently entered in the subject case.

Yours very truly,

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCD x
Artesia OCD x
Aztec OCD x

Other

Case 7209

Application of Koch Industries, Inc. for Tight Sand Designation

Mesaverde formation
San Juan County, New Mexico

Questions

1.) What are the present boundaries of the Rattlesnake Canyon Mesaverde formation Area?

2.) What is the basis for these boundaries

A. Dry holes?

B. Geologic Criteria? (Geometry of the producing formation)
Structure
Stratigraphic

C. Engineering limits? (producing data)

3.) Is Sec. 3, T. 31 N., R. 9 W., in the tight gas trend or in a producing trend with better reservoir characteristics?

Suggestion

The criteria used for establishing the limits of the tight gas formation designation areas should be physical criteria such as geologic or engineering data. The task should be in identifying the parameters that cause tight reservoir characteristics and then establish the limits of those parameters.

T 32 N, R 9W

Sec 34	Lot 1	36.83	35	40.08
	2	37.32		39.70
	3	.41		38.88
	4	.88		.52
	5	38.40		37.30
	6	37.93		.66
	7	38.59		39.38
	8	.10		.76
	9	.93		40
	10	39.18		38.93
	11	38.40		37.18
	12	.90		.01
	13	39.41		.24
	14	38.92		.35
	15	39.00		38.62
	16	38.75		39.08
		613.95		616.04

30	541.20
31	541.10
25	637.87
26	641.32
27	625.50
34	613.95
35	616.04
	4216.98

T32N R8

Sec 30 66.37 66.94

79.39 79.71 541.20 79.66

67.51

Sec 31 67.51

79.36 79.71 54110

68.37

32	25	1	39.46	26	39.71	27	1 39.51	
		2	50		76		2 38.86	
		3	59		81		3 ~~38.52~~	
		4	57		86		4 38.47	
		5	81		40.06		5 38.36	
		6	77		01		~~38.47~~	40.00
		7	73		39.96		~~38.52~~	40.00
		8	69		91		6 38.87	
		9	93		40.10		7 37.92	
		10	97		16		8 37.97	
		11	40.00		21		9 38.02	
		12	04		26			40.00
		13	27		41			40.06
		14	24		40			40.00
		15	20		35			40.00
		16	16		30			40.00
			397.87		641.32			625.50
			240					
			637.87					

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. A
CASE NO. 7209

KOCH INDUSTRIES, INC.

RATTLESNAKE CANYON TIGHT FORMATION AREA

The recommended Rattlesnake Canyon Mesaverde tight gas formation area is located in north-central San Juan County, adjacent to the Colorado state line on the southwest flank of the San Juan Basin. The proposed area includes the following lands:

T32N-R8W, Sections 7, 18-19, 30-31
T32N-R9W, Sections 10-15, 22-27, 34-35

This area is shown on Exhibit No. 1, a structure map of the Green Marker. This marker lies approximately 350' above the top of the Cliff House member of the Mesaverde, and is persistent across the mapped area. The map shows the regional dip to the northeast at generally less than $1/2^{o}$ across the proposed area.

Exhibit No. 2 is a type log of the Mesaverde formation in this area and shows the three members of the formation, the Cliff House, Menefee, and Point Lookout. The vertical limits of the Blanco Mesaverde gas pool in this area have been defined by the New Mexico Oil Conservation Division to be from the Huefanito Bentonite in the Lewis shale to a point 500' below the top of the Point Lookout member. The Huefanito Bentonite is a marker 816' uphole from the Green Marker. The Cliff House and Point Lookout members are considered to be the main producing zones in the field, but the less continuous sands of the Menefee also contribute to the overall production of the Mesaverde. In the proposed tight gas sand area, the Cliff House averages only about 50' thick and the pososity ranges from less than 4% to 15%. The Menefee in this area ranges from 230' to 290' thick and porosity varies from less than 3% to 17%. The main Point Lookout sands are about 150'-200' thick in this area although significant stringers of sand may be found as low as 300' below the top of the member. The porosity of the Point Lookout in the type well ranges from 3% to 14% and is considered typical

of the area. The average porosity for the sands of all three members is about 8%.

Exhibits No. 3 and 4 are west-east and southwest-northeast stratigraphic cross-sections through the area. They show the continuity of the Cliff House and Point Lookout sands across the area. They also show the irregularity of the sands in the Memefee.

The Point Lookout consists of nearshore or shoreline sands deposited during an overall regression of the Mancos Sea. The sand buildups represent periods of stillstand during the regression. The sands have been described as: light gray, very fine to fine grained, well cemented, often an argillaceous matrix, with poor visible porosity.

The Menefee represents a period of non-marine deposition during Mesaverde time. Environments of deposition include coal-forming swamps and coastal plain deposits. Numerous coals, silts, shales, and channel sands can be observed in a typical Menefee section. Reservoir quality often is similar to that of the Cliff House and Point Lookout sands, but the continuity and predictability of these Menefee sands is poor. Binocular description of the sands is not appreciably different than that of the Point Lookout.

The Cliff House consists of widespread shoreline sands deposited during transgression of the Lewis Sea. The sand buildups represent stillstands during that transgression. Again, binocular description of these sands is very similar to that of the Point Lookout and Menefee members.

The Cliff House in the proposed area is nearly to the point where it has pinched out completely, and within the 50' interval only about 10' is potentially productive. The gross interval (230'-280') of the Menefee contains only an average of 2 to 3 benches of potentially productive sand whereas to the south wells have a Menefee section of 1000' or more with several productive

intervals. The Point Lookout in this well is also near its seaward productive limit. Overall the area is near the productive limit of the various members of the Mesaverde. With relatively few objective zones in this area, the risk of drilling an uneconomic well is considerably greater than even a few miles to the south.

FRESH WATER PROTECTION

State and federal regulations assure that development drilling to the Mesaverde formation will not adversely affect any fresh water aquifers in the proposed tight formation area. Regulations require that casing programs be designed to seal off potential water bearing formations thus separating them from oil and gas bearing formations. Potential fresh water formations exist down to the base of the Ojo Alamo formation.

Exhibit No. 5 illustrates a typical casing program for Koch's wells in the area. A 14 3/4 inch hole is drilled to approximately 200 feet and 10 3/4 inch casing cemented in place with cement circulated to the surface. An 8 3/4 inch hole is drilled to approximately 3500 feet and 7 inch casing set with cement again being circulated to the surface. A 6 1/4 inch hole is gas drilled to total depth and 4 1/2 inch casing set and cemented with enough cement to extend up into the 7 inch casing. A temperature survey is run to determine the top of the cement. The exhibit shows that it is 4000 feet between the base of the Ojo Alamo and the intervals normally perforated, therefore the chance of a frac fluid or gas being communicated with fresh water is extremely remote. In the event that they are communicated Koch would squeeze the channel or perform whatever remedial work that would be required to isolate the intervals.

The upper 3500 feet of the well is drilled with natural mud which will not contaminate fresh water zones. During completion operations, each zone is broken down with approximately 500 gallons of 7 1/2 percent acid prior to frac. This small amount of acid will do little to contaminate an extensive aquifer, even in the

unlikely event it did communicate with a fresh water zone. Frac fluid consists of fresh water with approximately two percent KCl added. Again this fluid would do little to contaminate an extensive aquifer.

The good cementing practices and the casing design is such that any fresh water interval is protected by cement and at least one string of casing. Circulating cement to surface on the first two casing strings insures a good cement job. This along with the long interval between any fresh water zone and the producing formation makes it unlikely that fluids from the productive zones will come in contact with fresh water.

WELL DATA

Exhibit No. 6 is a production map of the tight formation and many of the surrounding wells. Anticipated ultimate production expected from the Koch operated wells as determined by Ryder Scott Petroleum Engineers (a Houston Texas based consulting firm) is shown. The map shows that to the south and west the cumulative gas production has been more than in the tight sand area.

Well data for wells not operated by Koch are shown on Exhibit No. 7. These wells were drilled prior to 1960 and all were stimulated. No pre stimulation rates were reported for the wells. Post stimulation rates range from a low of 145 MCFPD to a high of 3483 MCFPD AOF.

Exhibit No. 8 lists the Koch operated wells in the tight formation area. The first well was drilled in 1954. No additional wells were drilled until 1976. The results from the wells drilled in 1976 were disappointing and development was suspended until 1980 when two additional step out wells and one infill well was drilled. Koch has again stopped drilling due to poor economics.

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As many as seven or eight additional wells can be drilled on the Koch acreage alone if the economics are more favorable.

The only Koch operated well to produce measurable gas prior to stimulation was Gardner No. 1. The details of this test are not known, however it is doubtful that this represented a stabilized rate. All of the wells were drilled with gas, which provided a continuous test. The Gardner No. 4 was the only well with a slight show of gas while drilling. Gardner Well No. 5 produced at a rate too small to measure prior to stimulation.

Various types of well completions have been tried by Koch in an attempt to increase gas production. Each interval shown on the Exhibit has been frac treated alone. The number of intervals have been varied from two to three. Total frac treatments range in size from 80,000 pounds to massive 293,000 pounds.

The short term post stimulation flow rates should not be considered as representative of a wells long term ability to produce. Producing rates show a rapid decline following the initial potential.

The most recent wells drilled, Gardner No. 4-A and 5 cost $489,000 and $407,000 respectively to drill and complete. The respective amount paid to service companies to break down and frac the wells was $67,000 and $74,000.

PERMEABILITY CALCULATIONS

In a tight reservoir such as the Mesaverde in the tight formation area, it is difficult to establish pre stimulation permeability. The wells will not flow at a stable rate to permit the normal build-up analysis. None of the wells were cored, therefore adjusted or measured core permeabilities can not be used to determine permeability. The most convincing data available is the fact that the massive sands will not produce at sustained rates prior to stimulation and will not maintain high rates after stimulation.

The one pre stimulation flow rate available was used to calculate permeability using Darcy's Law. As mentioned earlier, this test data from Gardner Well No. 1 were not well documented. Certain assumptions were necessary to perform these calculations. It was assumed that the 47 MCFPD rate was a stabilized rate and the flowing wellhead pressure was at, or near atmospheric pressure. A porosity log was not run on the well, therefore a net pay of 149 feet based on Gardner Well No. 5 was assigned to the well.

Exhibit No. 9 presents the calculations used to determine permeability based on the test rate. The results show a permeability of 0.0208 Md. This is probably high as the rate was probably not stable.

Actual well test data from Gardner Well No. 3 were used in a computer program designed to calculate permeability based on performance. The basis of the analysis is from a paper by Gringarten, Ramey and Raghaven, which was published in Volume 257 of the AIME Transactions. Solution of the problem was made possible by the use of the Garrett Computing Systems' program - Gas Well Performance Simulation, which is obtaining industry-wide acceptance. Copies of the Gringarten et. al. and the Garrett documentation are included for easy reference by the U.S.G.S. and State of New Mexico staffs.

Basic assumptions in the computer program include a single uniform producing interval in a homogeneous reservoir. Of course the Mesaverde formation does not meet this requirement and the fact that intervals are frac treated separately will result in non-uniform fracture lengths. However, by entering data as though the reservoir is uniform should result in an indication of the permeability.

Exhibit No. 10 shows the test data, calculated flow rates and required fracture lengths for various permeabilities. Although an exact solution could not be obtained, it is reasonable to expect that the reservoir in situ gas permeability is between 0.001 and 0.002 Md.

ECONOMIC CONSIDERATIONS

Completion date, cumulative production and the current status of wells completed in the Mesaverde Formation in the proposed tight formation area are shown in Exhibit No. 11. Remaining reserves, as determined by Ryder Scott Engineers, are included for the Koch operated wells. A comparison of the completion date and the current status shows the rapid early production decline experienced by Gardner Wells 2, 3, 3-A and 4.

Exhibit No. 12 presents the estimated cost to drill and complete a trouble free Mesaverde well in the tight sand area. The last two wells drilled cost more than the $400,700 estimate.

Assumptions and results of an economic analysis for a well drilled in the tight gas formation area are shown in Exhibit No. 13. Production data used for the projection was taken from the first 25 years of history from Gardner Well No. 1. Page 1 of the exhibit shows that the discounted cash flow rate of return is 7 percent and the payout period is 9.4 years before income tax. These values are reduced to 6 percent rate of return with a 10.4 year payout

after income tax. Since no drilling difficulties or risk are included in the analysis, the actual parameters will be less attractive than shown. The long payout periods and low rates of return are not acceptable.

Section 107 tight gas formation prices will provide more favorable economics which will result in additional development in the tight formation area. An after tax analysis based on a $4.778/MCF Section 107 gas price resulted in a 20 percent rate of return and a 4 year payout which, while not excessive, is an acceptable rate of return.

CONCLUSIONS

Exhibit No. 14 presents a summary of pertinent reservoir data for the Mesaverde tight gas formation area. The average porosity of 11.3 percent represents a porosity based on an 8 percent cut off. Although a definite permeability value was not determined, the permeability is less than 0.1 Md and probably less than 0.02 Md. The exhibit also shows that the wells do not produce oil.

The Mesaverde formation in the proposed area meets the guidelines necessary to qualify the area for tight formation designation. These are:

1) The in situ permeability is less than 0.1 Md
2) The stabilized gas production rate is less than the 163 MCFPD maximum permitted for wells completed below 5000 ft.
3) No well will produce more than five barrels of oil per day.
4) Fresh water sands in the area will be adequately protected during drilling, completion and production operations.

In addition, wells completed in the area will show unfavorable economics with the existing gas price. The incentive of a higher gas price will result in additional wells being drilled.

KOCH INDUSTRIES, INC.

NUMBER, NAME AND PURPOSE

OF EACH EXHIBIT

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
1	Structure Map	Show structure in The Tight Formation Area
2	Type Log	Show log characteristics and depth of Mesaverde Formation
3	Cross Section A-A'	Show Mesaverde Formation development in a northwest-southeast direction
4	Cross Section B-B'	Show Mesaverde Formation development in a northeast-southwest direction
5	Schematic of Gardner Well No. 4-A	Show casing and cementing procedures to protect fresh water zones
6	Completion and Production Map	Show cumulative production from Mesaverde wells in and around the tight formation area, and expected ultimate production from Koch's wells
7	Wells Not Operated by Koch Industries	Show spud date, pre stimulation rate, type of stimulation and post stimulation rate of wells not operated by Koch
8	Flow Rates and Fracturing Information, Koch Operated Wells	Show spud date, pre stimulation rate, type of stimulation and post stimulation rate of wells operated by Koch
9	Calculated Permeability Based on Well Test From Gardner No. 1	Show calculated permeability from pre stimulation test
10	Calculated Permeability Based on Reservoir Simulation	Show calculated permeability for Gardner well No. 3 based on the Garrett Gas well performance simulation program

KOCH INDUSTRIES, INC.

NUMBER, NAME AND PURPOSE

OF EACH EXHIBIT

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

page 2)

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
11	Well Status and Reserves	List cumulative production, production and current status of all wells in the tight formation area and estimated ultimate production from Koch operated wells
12	Cost Estimate to Drill and Complete a Mesaverde Well	Show cost data used in economic calculations
13	Economics Based on Gardner Well No. 1 Production History	Show economics based on actual production history
14	Pertinent Reservoir Data	Show expected reservoir properties

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 7
CASE NO. 7209

EXHIBIT NO. 7

WELLS NOT OPERATED BY KOCH
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION RATE	TYPE OF STIMULATION	POST STIMULATION RATE MCFPD
Northwest Pipeline Corp.						
San Juan 32-8 Unit No. 24	A-19-32N-8W	6/20/57	5366 - 5816	NR*	Sand-Water Frac	1708 AOF
El Paso Natural Gas Company						
San Juan 32-9 Unit No. 10	G-34-32N-9W	9/8/53	5395 - 5960 OH	NR	Shot w/165 qts	145 IP
San Juan 32-9 Unit No. 11	A-14-32N-9W	10/16/53	5763 - 6280 OH	NR	Shot w/1335 qts	648 IP
San Juan 32-9 Unit No. 52	M-13-32N-9W	12/1/57	5718 - 6228	NR	Sand-Water Frac	288 IP
San Juan 32-9 Unit No. 53	M-27-32N-9W	8/5/57	5672 - 6234	NR	Sand-Water Frac	2818 AOF
San Juan 32-9 Unit No. 54	L-14-32N-9W	11/11/57	5748 - 6238	NR	Sand-Water Frac	3483 AOF
San Juan 32-9 Unit No. 66	M-10-32N-9W	5/27/58	5930 - 6398	NR	Sand-Water Frac	1811 AOF

* NR - Not Reported

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 8
CASE NO. 7209

EXHIBIT #8

FLOW RATES AND FRACTURING INFORMATION, KOCH OPERATED WELLS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

WELL NAME AND NUMBER	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION FLOW RATE MCF/D	POST STIMULATION FLOW RATE MCF/D	SIZE FRAC TREATMENT GALS	# SAND
Gardner No. 1	M-35-32N-9W	6-4-54	5192-6100	47	1503	2880 quarts	
Gardner No. 2	G-31-32N-8W	3-25-76	5760-5862 5518-5666 5078-5464	No gas while drilling	965	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3	N-31-32N-8W	11-23-76	5755-5996 5419-5682 5059-5160	No gas while drilling	2290	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3-A	P-31-32N-8W	1-27-80	5706-5847 5414-5626	No gas while drilling	1304	80,000 30,000 110,000	80,000 30,000 110,000
Gardner No. 4	M-25-32N-9W	12-8-76	5772-5946 5538-5592 5083-5162	Slight show of gas while drilling	3200	50,000 20,000 10,000 80,000	50,000 20,000 10,000 80,000
Gardner No. 4-A	P-25-32N-9W	9-4-80	5807-6008 5620-5735	No gas while drilling	2120	200,000 106,500 306,500	200,000 93,000 293,000
Gardner No. 5	M-26-32N-9W	9-23-80	5644-5793 5440-5531	TSTM No gas while drilling	1800	160,000 60,000 220,000	150,000 60,000 210,000

Note: All wells were drilled with gas which provided a continuous test

EXHIBIT NO. 9

CALCULATED PERMEABILITY BASED
ON WELL TEST FROM GARDNER NO. 1
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation at permeability with Darcy's Law

$$k = \frac{QU_gTZ \ln(0.61\ r_e/r_w)}{703\ h(Pe^2 - Pf^2)}$$

Where:

- Q = gas flowing rate, SCF/D - 47,000
- U_g = gas viscosity, cp calculated as 0.0142
- T = reservoir temperature, R^O - 610
- Z = gas compressibility calculated as 0.9091
- r_e = drainage radius of 1490ft. for 160 acres
- r_w = wellbore radius of 0.26 ft.
- h = net pay estimated at 149 feet from Gardner well No. 5. A porosity log was not run on the Gardner No. 1.
- P_e = static shut-in reservoir pressure at drainage radius r_e, psia calculated as 1177
- P_f = Flowing subsurface pressure, psia estimated as 45 psia

k is permeability in Darcies

$$k = \frac{(47{,}000 \times 0.0142 \times 610 \times 0.9091 \ln(0.61 \times 1490/0.26)}{703 \times 149 \times (1177^2 - 45^2)}$$

$k = 0.0000208$ D.
$= 0.0208$ md

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 9
CASE NO. 7209

EXHIBIT NO. 10

CALCULATED PERMEABILITY BASED ON RESERVOIR SIMULATION
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

INPUT DATA FROM GARDNER WELL NO. 3

Porosity - 11.7%
Net Pay - 250 ft.
Liquid Saturation - 55%
Reservoir Temperature - 150° F
Drainage Area - 160 acres
Test Data -

Date	Rate MCFPD	Flowing WHP, Psi
8-17-79	Date of initial production	
8-23-79	1300	450
9-4-79	697	320
5-20-80	143	350
2-10-80	115	295

RESULTS

Fracture Half Length, ft.	Permeability Md	*1300	*697	*143	*115
750	0.002	1566	1016	222	173
600	0.002	1255	808	185	145
625	0.0013	1050	675	148	115
650	0.00125	1072	688	151	116
650	0.00122	1058	679	148	115
638	0.00126	1055	677	149	115

A reasonable history match is shown for all except the first flow period with permeabilities from 0.00122 to 0.0013 Md. Calculations are made assuming a homogenous reservoir.

* Test rates. All calculated rates are at the measured wellhead pressures.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 10
CASE NO. 7209

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 11
CASE NO. 7209

EXHIBIT NO. 11

WELL STATUS AND RESERVES
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	DATE OF INITIAL PRODUCTION	CUMULATIVE PRODUCTION 10-31-80, MCF	ESTIMATED REMAINING RESERVES, MCF	ESTIMATED ULTIMATE RESERVES, MCF	OCTOBER,1980 STATUS
Koch Industries, Inc.					
Gardner No. 1	9-54	426,694	95,306	522,000	564 MCF/M
Gardner No. 2	8-79	77,104	518,896	596,000	3712 MCF/M
Gardner No. 3	8-79	102,071	427,929	530,000	4225 MCF/M
Gardner No. 3-A	9-80	25,172	504,828	530,000	21676 MCF/M
Gardner No. 4	8-79	93,799	269,201	363,000	2807 MCF/M
Gardner No 4-A	----	0	480,000	480,000	Waiting on PL connection
Gardner No. 5	----	0	480,000	480,000	Waiting on PL connection
Northwest Pipeline Corp.					
San Juan Unit 32-8 No. 24	12-57	205,693			654 MCF/M
El Paso Natural Gas Company					
San Juan 32-9 Unit No. 10	1-54	1,840	0	1,840	P & A
San Juan 32-9 Unit No. 11	4-54	2,366	0	2,366	P & A
San Juan 32-9 Unit No. 52	8-57	34,896	0	34,896	P & A
San Juan 32-9 Unit No. 53	1-58	395,430			742 MCF/M
San Juan 32-9 Unit No. 54	5-58	656,174			1255 MCF/M
San Juan 32-9 Unit No. 66	1-59	174,879			287 MCF/M

KOCH EXPLORATION COMPANY

EXHIBIT #12

DETAIL WELL ESTIMATE

LEASE NO. _____ AFE NO. _____ OUR W. I. _____

LEASE NAME AND WELL NO. Gardner Area LOCATION _____

DISTRICT _____ COUNTY San Juan STATE New Mexico FIELD OR AREA _____

EST. T. D. 6200 FT. OPERATOR Koch Exploration DATE February, 1981

		Producer	Dry Hole
Drilling Intangibles:			
1 – LOCATION EXPENSE:			
DIG PITS $ 2,000 FILL PITS $ 2,000 ROADS-BRIDGES $ 4,000			
DRGD.-GRADE $ _____ SURV. LOCATION $ 300 DAMAGES $ 500			
STATE-MISC. FEES $ _____ MISC. (LIST) $ _____			
	FEATURE TOTAL $	8,800	$ _____
11 – RIG COSTS: 17 days @ 5,800			
DRILLING _____ FT. AT $ _____/FT. $ _____ DAY WORK $ 98,600			
BITS-REAMERS $ 6,000 WATER $ _____ MIRT-MORT $ 8,000			
COMPRESSORS $ _____ CABLE TOOLS $ _____ FUEL-SUPPLIES $ _____			
BOILER CHG $ _____ SWAB UNIT $ 5 days @ 1,400 = 7,000			
MISC. (LIST) $ _____			
	FEATURE TOTAL $	131,600	$ _____
20 – CEMENT AND SERVICES:			
CEMENT AND SERVICE: SURFACE $ 700 INTR. $ 5,100 PROD $ 2,000			
FLOATS $ _____ CENTRALIZERS $ _____ GUIDES $ _____			
STAGE TOOLS $ _____ SCRATCHERS $ _____ PLUGGING $ _____			
SQUEEZES $ _____ MISC (LIST) $ _____			
	FEATURE TOTAL $	7,800	$ _____
21 – DRILLING FLUIDS:			
MUD $ 15,000 CHEMICALS $ _____ OIL $ _____			
MISC. (LIST) $ _____			
	FEATURE TOTAL $	15,000	$ _____
22 – WELL SURVEYS AND TESTING:			
CORING $ _____ CORE HEADS $ _____ TEMP. SURV. $ 300			
CALIPER SURV. $ _____ ELEC. SURV. $ 15,300 MUD LOG $ _____			
D. S. T. S _____ AT $ _____ EA. $ _____ RADIATION LOG $ _____			
MISC. (LIST) $ _____			
	FEATURE TOTAL $	15,600	$ _____
23 – SPECIAL SERVICES:			
PERFORATING $ 10,000 PLUGS-RETAINERS $ _____ ACID $ _____			
FRAC. $ 65,000 MISC. TOOL RENTAL $ _____			
	FEATURE TOTAL $	75,000	$ _____
30 – LABOR AND SUPERVISION:			
CO. LABOR $ _____ SUPV.-PERS. EXP. $ _____ OVERHEAD $ _____			
DIST EXP. $ _____ CONTRACT LABOR $ _____ COMMUNICATION $ _____			
	FEATURE TOTAL $	_____	$ _____
40 – TRANSPORTATION:			
CO. CARS $ 500 AIR TRAVEL $ _____			
TRUCKING (CASING, TUBING, CABLE TOOLS) $ 10,000			
	FEATURE TOTAL $	10,500	$ _____
41 – OTHER COSTS:			
(ITEMIZE) _____			
	FEATURE TOTAL $	_____	$ _____
45 – CONTINGENCY: 15%	$	39,600	$ _____
	TOTAL INTANGIBLES $	303,900	$ _____
Well Equipment:			
51 – CASING AND TUBING (SIZE, WT., GRD., CPLG., NEW OR USED)			
200 FT. OF 28# 10-3/4" AT $ 17.91 /FT. $ 3,600			
3600 FT. OF 20 & 26# 7" AT $ 8.00 /FT. $ 28,800			
6200 FT. OF 10.5# 4-1/2" AT $ 5.15 /FT. $ 31,900			
6000 FT. OF 4.7# 2-3/8" AT $ 2.92 /FT. $ 17,500			
	FEATURE TOTAL $	81,800	$ _____
52 – CASING HD. $ 1,000 XMAS TREE OR PUMPING CONNECTION $ 2,000	$	3,000	$ _____
53 – PUMPING UNIT $ _____ ENGINE OR ELECTRIC MOTOR $ _____	$	_____	$ _____
55 – SUCKER RODS _____ $ _____			
PUMP $ _____ POLISHED ROD $ _____ FEATURE TOTAL $		_____	$ _____
62 – TANKS 1 AT $ 3,850 EA. $ _____ BUILD BATTERY $ _____			
FLOWLINES 100 FT. OF _____ AT $ 2.50 PER FT. $ 250			
LAY FLOWLINES $ 200 FENCING-PAINTING $ _____ VALVES-FITTINGS $ 200			
	FEATURE TOTAL $	4,500	$ _____
63 – SEPARATOR $ _____ HTR. TRTR. $ _____ DEHYDRATION EQUIP. $ _____	$	_____	$ _____
71 – METERING EQUIP. $ _____	$	_____	$ _____
72 – OTHER (ITEMIZE) Gas Package Unit _____	$	7,500	$ _____
_____ TOTAL TANGIBLES	$	96,800	$ _____
REMARKS _____ TOTAL ESTIMATE	$	400,700	$ _____
_____ LESS CONTRIBUTIONS	$	_____	$ _____
_____ NET WELL COST	$	_____	$ _____
_____ OUR NET COST	$	_____	$ _____

ORIGINATED BY _____ DATE _____ APPROVED _____ DATE _____

APPROVED _____ DATE _____ APPROVED _____ DATE _____

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
KOCH EXHIBIT NO. 12
CASE NO. 7809

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 13
CASE NO. 7209

EXHIBIT NO. 13

ASSUMPTIONS AND RESULTS OF ECONOMIC CALCULATIONS

RATTLESNAKE CANYON TIGHT FORMATION AREA

BLANCO MESAVERDE FIELD

SAN JUAN COUNTY, NEW MEXICO

ASSUMPTIONS

Drilling and Completion Costs, $	400,700
Expense Interest, %	100
Royalty Interest, %	15
Yield, BBL/MMCF	0
Gas Price, $/MCF	2.389
Severance Tax, %	8
Operating Costs, $/well/yr.	4800
Income Tax Rate, %	48.7
Time Projected, yrs.	25

Producing Rate - Same as Actual Production From Gardner Well No. 1 (413 MMCF in 25 yrs)

RESULTS

Before Income Tax Results:

Discounted Cash Flow Rate of Return, %	7
Payout, yrs.	9.4
Cash Flow, $	259,796

After Income Tax Results:

Discounted Cash Flow Rate of Return, %	6
Payout, yrs.	10.4
Cash Flow, $	142,960

EXHIBIT NO. 13
ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

CURRENT DATE 02/04/81

INVESTMENT ANALYSIS GARDNER AREA WELL NO 1 AT TODAYS COSTS AND PRICE PROJECT LIFE 25 YEARS TAX RATE .48700 DPL .00

INVESTMENT REQUIRED

YEAR	LAND	DEPRECIABLE	DEPLETABLE	WORKING CAP	GOODWILL	TOTAL	SALV PCT	METHOD	INVEST LIFE	TAX CREDIT SUBJ TO INV	PROJECT RECOVERY	IDC PCT	YR
0	0	96,800	303,900	0	0	400,700	.000	4	25.0	96,800	0	.999	0
***	0	96,800	303,900	0	0	400,700				96,800	0		

LOANS REQUIRED

YEAR	PRINCIPAL	PAYOFF PERIOD	INTEREST RATE	DEBT LIQUIDATION	PAYMENT FREQUENCY
TOTAL	0			0	

INPUT VARIABLES -

WORKING INTEREST	BFO	1.0000000			
REVENUE INTEREST	BFO	.8500000			
PRODUCTION TAX RATES	GAS	.0800000	COND	.0000000	
PRINCIPAL PRODUCT	GAS				

REVENUE & COST EXTENSIONS

YEAR	GROSS DAILY GAS - MCF	NET ANNUAL GAS - MCF	GAS PRICE	REVENUE GENERATED	GROSS DAILY COND - STB	NET ANNUAL COND - STB	COND PRICE	REVENUE GENERATED	OPERATING COST	PRODUCTION TAX	OVERHEAD COST
0- 1	95	29,776	2.3890	71,135					4,800	5,691	
1- 2	95	29,740	2.3890	71,049					4,800	5,684	
2- 3	88	27,311	2.3890	65,246					4,800	5,220	
3- 4	76	23,762	2.3890	56,767					4,800	4,541	
4- 5	71	22,257	2.3890	53,172					4,800	4,254	
5- 6	58	18,184	2.3890	43,442					4,800	3,475	
6- 7	41	12,964	2.3890	30,971					4,800	2,478	
7- 8	50	15,574	2.3890	37,206					4,800	2,976	
8- 9	58	18,020	2.3890	43,050					4,800	3,444	
9-10	39	12,151	2.3890	29,029					4,800	2,322	
10-11	28	8,917	2.3890	21,303					4,800	1,704	
11-12	24	7,548	2.3890	18,032					4,800	1,443	
12-13	33	10,486	2.3890	25,051					4,800	2,004	
13-14	29	9,257	2.3890	22,115					4,800	1,769	
14-15	36	11,255	2.3890	26,888					4,800	2,151	
15-16	44	13,801	2.3890	32,971					4,800	2,638	
17-18	44	13,725	2.3890	32,789					4,800	2,623	
18-19	29	9,026	2.3890	21,563					4,800	1,725	
19-20	42	13,160	2.3890	31,439					4,800	2,515	
20-21	26	8,287	2.3890	19,798					4,800	1,584	
21-22	22	6,890	2.3890	16,460					4,800	1,317	
22-23	22	7,002	2.3890	16,728					4,800	1,338	
23-24	17	5,407	2.3890	12,917					4,800	1,033	
24-25	17	5,545	2.3890	13,247					4,800	1,060	
TOTAL	413,190	355,113		848,365					120,000	67,869	
	GROSS BBLS (MCF)			GROSS BBLS(MCF)							

EXHIBIT NO. 13

ECONOMIC CALCULATIONS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

CASH FLOW CALCULATIONS

YEAR	TOTAL INCOME	TOTAL COSTS	DEPREC-IATION	INTEREST	INCOME TAX	TAX DEPLETION	BOOK DEPLETION	NET INCOME	DEBT LIQUIDATION	CASH FLOW
0										400,700-*
0- 1	71,135	10,491	8,117		132,099-		25,481	159,145		192,743
1- 2	71,049	10,484	8,107		25,547		25,451	1,460		35,018
2- 3	65,246	10,020	7,445		23,269		23,372	1,140		31,957
3- 4	56,767	9,341	6,477		19,942		20,335	672		27,484
4- 5	53,172	9,054	6,067		18,531		19,047	473		25,587
5- 6	43,442	8,275	4,957		14,712		15,561	63-		20,455
6- 7	30,971	7,278	3,534		9,817		11,094	752-		13,876
7- 8	37,206	7,776	4,245		12,265		13,327	407-		17,165
8- 9	43,050	8,244	4,912		14,558		15,421	85-		20,248
9-10	29,029	7,122	3,312		9,056		10,398	859-		12,851
10-11	21,303	6,504	2,431		6,023		7,631	1,286-		8,776
11-12	18,032	6,243	2,058		4,739		6,459	1,467-		7,050
12-13	25,051	6,604	2,858		7,494		8,973	1,078-		10,753
13-14	22,115	6,569	2,523		6,342		7,921	1,240-		9,204
14-15	26,883	6,951	3,068		8,215		9,631	977-		11,722
15-16	32,971	7,438	3,762		10,602		11,810	641-		14,931
16-17	35,997	7,680	4,107		11,790		12,894	474-		16,527
17-18	32,789	7,423	3,741		10,531		11,745	651-		14,835
18-19	21,563	6,525	2,460		6,125		7,724	1,271-		8,913
19-20	31,439	7,315	3,587		10,002		11,262	727-		14,122
20-21	19,798	6,384	2,259		5,432		7,091	1,368-		7,982
21-22	16,460	6,117	1,878		4,122		5,896	1,553-		6,221
22-23	16,728	6,138	1,909		4,228		5,992	1,539-		6,362
23-24	12,917	5,833	1,474		2,732		4,627	1,749-		4,352
24-25	13,247	5,860	1,512		2,861		4,745	1,731-		4,526
TOTAL	848,365	187,869	96,800		116,836		303,688	142,972		142,960

* = NET CASH INVESTMENT OR SALVAGE

AFIT
DCF RATE OF RETURN 5.98 PER CENT
PAYBACK PERIOD 10.37 YEARS

BFIT
DCF RATE OF RETURN 6.98 PER CENT
PAYBACK PERIOD 9.43 YEARS

EXHIBIT NO. 14

PERTINENT RESERVOIR DATA

Datum Depth, Ft.	5750
Original Reservoir Pressure, Psia	1177
Reservoir Temperature, ^{o}F	150
Average Net Pay, ft. (Koch's Wells)	156
Average Porosity, % (Koch's Wells)	11.3
Expected Permeability, Md	<0.02
Oil Production, BOPD	None

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
Koch EXHIBIT NO. 14
CASE NO. 7209

EXHIBIT NO. 7

WELLS NOT OPERATED BY KOCH
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION RATE	TYPE OF STIMULATION	POST STIMULATION RATE MCFPD
Northwest Pipeline Corp.						
San Juan 32-8 Unit No. 24	A-19-32N-8W	6/20/57	5366 - 5816	NR*	Sand-Water Frac	1708 AOF
El Paso Natural Gas Company						
San Juan 32-9 Unit No. 10	G-34-32N-9W	9/8/53	5395 - 5960 OH	NR	Shot w/165 qts	145 IP
San Juan 32-9 Unit No. 11	A-14-32N-9W	10/16/53	5763 - 6280 OH	NR	Shot w/1335 qts	648 IP
San Juan 32-9 Unit No. 52	M-13-32N-9W	12/1/57	5718 - 6228	NR	Sand-Water Frac	288 IP
San Juan 32-9 Unit No. 53	M-27-32N-9W	8/5/57	5672 - 6234	NR	Sand-Water Frac	2818 AOF
San Juan 32-9 Unit No. 54	L-14-32N-9W	11/11/57	5748 - 6238	NR	Sand-Water Frac	3483 AOF
San Juan 32-9 Unit No. 66	M-10-32N-9W	5/27/58	5930 - 6398	NR	Sand-Water Frac	1811 AOF

* NR - Not Reported

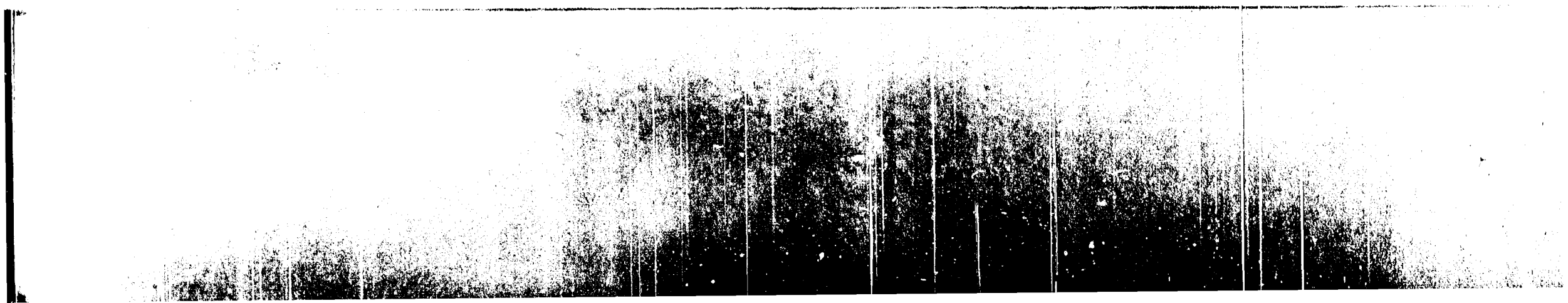
EXHIBIT #8

FLOW RATES AND FRACTURING INFORMATION, KOCH OPERATED WELLS
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

WELL NAME AND NUMBER	LOCATION	SPUD DATE	COMPLETION INTERVAL	PRE STIMULATION FLOW RATE MCF/D	POST STIMULATION FLOW RATE MCF/D	SIZE FRAC TREATMENT GALS	# SAND
Gardner No. 1	M-35-32N-9W	6-4-54	5192-6100	47	1503	2880 quarts	
Gardner No. 2	G-31-32N-8W	3-25-76	5760-5862 5518-5666 5078-5464	No gas while drilling	965	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3	N-31-32N-8W	11-23-76	5755-5996 5419-5682 5059-5160	No gas while drilling	2290	50,000 50,000 50,000 150,000	50,000 50,000 50,000 150,000
Gardner No. 3-A	P-31-32N-8W	1-27-80	5706-5847 5414-5626	No gas while drilling	1304	80,000 30,000 110,000	80,000 30,000 110,000
Gardner No. 4	M-25-32N-9W	12-8-76	5772-5946 5538-5592 5083-5162	Slight show of gas while drilling	3200	50,000 20,000 10,000 80,000	50,000 20,000 10,000 80,000
Gardner No. 4-A	P-25-32N-9W	9-4-80 189,000 total cost	5807-6008 5620-5735	No gas while drilling	2120 67020	200,000 106,500 306,500	200,000 93,000 293,000
Gardner No. 5	M-26-32N-9W	9-23-80 407,000 total cost	5644-5793 5440-5531	TSTM No gas while drilling	1800 74000	160,000 60,000 220,000	150,000 60,000 210,000

Note: All wells were drilled with gas which provided a continuous test

pd to frac company



Ex 9

$$K = \frac{47000 \times 0.0142 \times 610 \times 0.9091 \times \ln 0.61 \frac{1490}{.26}}{703 \times 149 \times (1177^2 - 45^2)}$$

$$= 2.08411 - 05 = .0000208 \text{ darcies}$$

$$.0000208 \times 1000 = .0208 \text{ md}$$

Ex 9

EXHIBIT NO. 9

CALCULATED PERMEABILITY BASED
ON WELL TEST FROM GARDNER NO. 1
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation at permeability with Darcy's Law

$$k = \frac{QU_gTZ \ln(0.61\ r_e/r_w)}{703\ h(Pe^2 - Pf^2)}$$

Where:

- Q = gas flowing rate, SCF/D - 47,000
- U_g = gas viscosity, cp calculated as 0.0142
- T = reservoir temperature, R^o - 610
- Z = gas compressibility calculated as 0.9091
- r_e = drainage radius of 1490ft. for 160 acres
- r_w = wellbore radius of 0.26 ft.
- h = net pay estimated at 149 feet from Gardner well No. 5. A porosity log was not run on the Gardner No. 1.
- P_e = static shut-in reservoir pressure at drainage radius r_e, psia calculated as 1177
- P_f = Flowing subsurface pressure, psia estimated as 45 psia

k is permeability in Darcies

$$k = \frac{(47{,}000 \times 0.0142 \times 610 \times 0.9091 \ln(0.61 \times 1490/0.26)}{703 \times 149 \times (1177^2 - 45^2)}$$

k = 0.0000208 D.
- 0.0208 md

OK

EXHIBIT NO. 10

CALCULATED PERMEABILITY BASED ON RESERVOIR SIMULATION
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

INPUT DATA FROM GARDNER WELL NO. 3

Porosity - 11.7%
Net Pay - 250 ft.
Liquid Saturation - 55%
Reservoir Temperature - 150° F
Drainage Area - 160 acres
Test Data -

Date	Rate MCFPD	Flowing WHP, Psi
8-17-79	Date of initial production	
8-23-79	1300	450
9-4-79	697	320
5-20-80	143	350
2-10-~~80~~ 81	115	295

RESULTS

Fracture Half Length, ft.	Permeability Md	*1300	*697	*143	*115
750	0.002	1566	1016	222	173
600	0.002	1255	808	185	145
625	0.0013	1050	675	148	115
650	0.00125	1072	688	151	116
650	0.00122	1058	679	148	115
638	0.00126	1055	677	149	115

A reasonable history match is shown for all except the first flow period with permeabilities from 0.00122 to 0.0013 Md. Calculations are made assuming a homogenous reservoir.

* Test rates. All calculated rates are at the measured wellhead pressures.

EXHIBIT NO. 11

WELL STATUS AND RESERVES
RATTLESNAKE CANYON TIGHT FORMATION AREA
BLANCO MESAVERDE FIELD
SAN JUAN COUNTY, NEW MEXICO

OPERATOR WELL NAME	DATE OF INITIAL PRODUCTION	CUMULATIVE PRODUCTION 10-31-80, MCF	ESTIMATED REMAINING RESERVES, MCF	ESTIMATED ULTIMATE RESERVES, MCF	OCTOBER,1980 STATUS
Koch Industries, Inc.					
Gardner No. 1	9-54	426,694	95,306	522,000	564 MCF/M
Gardner No. 2	8-79	77,104	518,896	596,000	3712 MCF/M
Gardner No. 3	8-79	102,071	427,929	530,000	4225 MCF/M
Gardner No. 3-A	9-80	25,172	504,828	530,000	21676 MCF/M
Gardner No. 4	8-79	93,799	269,201	363,000	2807 MCF/M
Gardner No 4-A	----	0	480,000	480,000	Waiting on PL connection
Gardner No. 5	----	0	480,000	480,000	Waiting on PL connection
Northwest Pipeline Corp.					
San Juan Unit 32-8 No. 24	12-57	205,693			654 MCF/M
El Paso Natural Gas Company					
San Juan 32-9 Unit No. 10	1-54	1,840	0	1,840	P & A
San Juan 32-9 Unit No. 11	4-54	2,366	0	2,366	P & A
San Juan 32-9 Unit No. 52	8-57	34,896	0	34,896	P & A
San Juan 32-9 Unit No. 53	1-58	395,430			742 MCF/M
San Juan 32-9 Unit No. 54	5-58	656,174			1255 MCF/M
San Juan 32-9 Unit No. 66	1-59	174,879			287 MCF/M

GASWELL Program

User's Manual

2/79

Gas Well Performance Simulation Program

GARRETT COMPUTING SYSTEMS

DALLAS, TEXAS

GAS WELL PERFORMANCE SIMULATOR

Program GASWELL

FEBRUARY 1979

GARRETT COMPUTING SYSTEMS

PREFACE

This manual contains detailed instructions for the use of the subject program in the applications for which it was designated. It is written for engineers, geologists and other professional employees within the petroleum industry. They need not be computer programmers. However, familiarity with the computing system on which this program has been placed is recommended.

This program is a part of an expanding library of time-sharing programs developed by Garrett Computing Systems, Inc. for use by its subscribers. All programs in the GCS library are run-only programs, meaning that they cannot be listed or permanently modified by the user. The terms under which they are made available may vary between programs or may vary with a given program from time to time. Garrett Computing Systems reserves the right to change these terms at its discretion. Questions regarding use of the program library should be directed to:

Garrett Computing Systems, Inc.
Dallas, Texas 75201
Telephone: 741-1026 (A/C 214)

The programs in the GCS library have been extensively tested and to the best of our ability are error-free. However, due to the very complex nature of many of them, GCS cannot warrant that program errors will not be found on occasion. Should this occur, please contact Garrett Computing Systems immediately. Garrett Computing Systems shall not be responsible or liable for the validity or use of the answers derived from the use of the material contained in this booklet or for the program(s) for which it applies.

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TECHNICAL NOTES

ABOUT THE PROGRAM

General

The GASWELL program is used to forecast production from hydraulically fractured gas wells. Reservoir and fracture descriptions are provided by the user along with wellhead pressure and producing rate constraints. The program computes values for producing rate, wellhead pressure, cumulative production and cumulative recovery. Additional features in the program allow the user to compare production history or pressure buildup tests to computed values on the basis of either wellhead pressure or producing rate, and thus determine whether the input reservoir and fracture descriptions are satisfactory.

Input

Input data forms are available on which the user's data should be recorded. These data are subsequently placed in an input file prior to running the GASWELL program. Data for only one case can be placed in a single file. If more than one case is to be run, each case should be placed in a separate file.

Output

The GASWELL program prepares a two-page tabular report for production forecasts. The report is generally stored in an output file which the program creates under a name selected by the user. A description of each page is as follows:

First Page - The first page contains a recap of the input data with the computed value for initial total system compressibility. The information is subdivided into categories for reservoir properties, reservoir geometry, fluid properties, and flowstream data.

Second Page - This page, entitled "Predicted Performance", contains a printout by time frame of the forecasted variables. The values tabulated on this page are time, flowing wellhead pressure, flowing bottom-hole pressure, average shut-in reservoir pressure, producing gas rate, cumulative production, cumulative percent recovery, and Z-factor at average reservoir conditions. If the user exercises the option of providing constraints from the terminal during execution, the forecasted values are printed directly on the terminal in addition to being placed in the output data file.

When a comparison based on observed history is performed, the output is different from that of a forecast. As with a production forecast, a recap of the input data is provided on the first page of output. The second page, entitled

"Performance Comparison", contains a table of computed and observed values versus time. The tabulated values are time, observed wellhead pressure, calculated wellhead pressure, observed rate, and calculated rate. In addition to being placed in the output data file, the performance comparison report is also printed on the user's terminal.

Processing Technique

The processing technique used by the GASWELL program is outlined below:

1. All input data is read and converted to standard units.

2. The initial total system compressibility is computed.

3. Real gas pseudo-pressures are computed for pressures ranging up to the initial reservoir pressure based on the gas gravity and computed values for gas viscosity and Z-factor.

4. Internal tables are generated for dimensionless pressure drop versus dimensionless time based on the user's reservoir geometry. These solution tables are discussed further in the Technical Notes section.

5. A time-step is taken and the deliverable rate against the scheduled wellhead pressure is computed. If this rate is in excess of the maximum allowable rate, the wellhead pressure corresponding to the allowable rate is computed.

6. Production for the time interval and the flowing bottom-hole pressure are both calculated based on the rate determined in Step 5.

7. The average reservoir pressure is computed by material balance based on the production increment established in Step 6.

8. Cumulative percent recovery and Z-factor at reservoir conditions are computed.

9. The above process is repeated from Step 5 until the ending time or minimum producing rate is reached.

10. The output report is printed.

Principal Features

The following features are included in the GASWELL program.

1. Production forecasts can be obtained based on production constraints such as minimum wellhead pressure and maximum allowable rate. Production constraints can be varied as a function of time.

2. The forecast may be started at any time subsequent to the specified initial date. In addition, the user may specify the desired output frequency.

3. Observed wellhead pressures or production rates may be compared to computed values. Short-term or long-term data may be used.

4. A rectangular drainage shape may be specified along with the well location within the drainage area.

5. Either uniform flux or infinite conductivity fractures may be considered.

6. Real gas pseudo pressures are computed based on input gas gravity. Adjustments to gas properties can be made for the presence of H_2S, CO_2 and N_2.

7. An interactive mode exists which allows the user to control the progress of either production forecasts or production comparisons.

Assumptions

The following assumptions have been incorporated into the calculations.

1. The fracture is vertical.

2. The fracture can be characterized either as possessing infinite conductivity or having uniform mass flux within the fracture plane.

3. The reservoir matrix has constant properties throughout.

4. A single producing layer exists of uniform thickness.

5. The wellbore is located at the center of the fracture.

6. The fracture is parallel to the drainage boundary.

7. The drainage boundary is either square or rectangular.

8. Fluid flow within the reservoir is single-phase gas.

Program Calculation Step Size Selection

For increased accuracy in its internal predictive calculations the program selects an initial time-step size of one-half day, then doubles this size for each succeeding step until a step size of one month is reached. This value is then held constant until three years have elapsed since the calculations began. Quarterly steps are taken until a total of six years has passed, whereupon the step size is set at six months for the duration of the run.

The program will automatically alter these time step sizes to accommodate output dates specified on lines 701-799 (or input as response to question on output frequency). Thus the user may override the built-in time steps by specifying each desired interval on the 701-799 lines.

PREPARATION OF DATA

Form Available

A GASWELL input form has been developed for recording all necessary input data. A copy has been included at the back of this manual. Additional copies may be reproduced from this manual or ordered in pad form from GCS.

Multiple Cases

Data for each case (one input data sheet) should be placed in a separate computer file before processing.

Line Numbers

The line numbers shown on the input data form serve two purposes. They tell the program the nature of the data on the line and permit proper sequencing before processing. Only the line numbers indicated on the form or in this chapter may be used.

Data Format

With the exception of lines 101-103, all input is in free form. This means that the basic requirement for spacing of data is that each word entry be separated from the next by at least one blank space. Inclusion of decimal points is permitted. All data spaces must be filled in on each line. Data items not used must contain a zero instead of a blank.

Lines 101-103 (Run Description)

101	YOURWELL NO. 3
102	ROUNDHOUSE FIELD
103	FREMONT CO., WYOMING

These three lines contain heading information for the printout. Recommended information for these lines includes well name and number, field and zone, and county and state. Any alphanumeric descriptions can be placed on these lines provided, however, that the maximum number of characters, including blanks, does not exceed 24 on any line.

Line 200 (Reservoir Data)

	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation, %	Temperature of Zone, °F
200	.53	4.7	115	53	197

This line contains the basic reservoir parameters. All five items on this line are required and are described as follows:

1. Permeability, Md. - Enter the matrix permeability of the producing interval.

2. Porosity, % - Specify the total porosity of the producing interval as a percent of the bulk volume.

3. Net Pay, Feet - Enter the net thickness of the producing interval. The program assumes that the fracture extends from the top to the bottom of the net interval and that the interval is of constant thickness throughout the drainage area.

4. Liquid Saturation, % - Enter the total liquid saturation for the producing interval. The program assumes this value to be constant throughout the drainage area and for the life of the project.

5. Temperature of Zone, Degrees F - Show the average reservoir temperature. The program assumes this value to be constant for the project life.

Line 210 (Fracture Data)

	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210	500	2640	2640	1320	1320

All items on this line are required. The data on this line describe the fracture length, the size of the drainage area and the position of the fracture within the drainage area. Note that the fracture must be oriented in the X-direction. Refer to Figure 1 for the discussion of the following items:

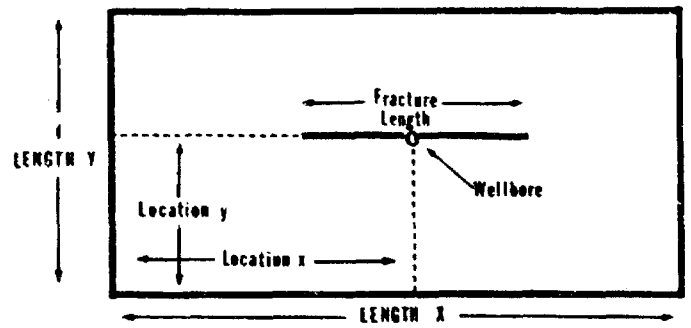

Fig. 1

1. Fracture Length, Feet - Enter the tip-to-tip fracture length in feet. If a value less than one foot is entered, the program will assume that the item entered is a wellbore radius and that no fracture exists.

2. Drainage Area Length X, Feet - Enter the length corresponding to length X in Figure 1. This is the total length of the drainage area in the X-direction.

3. Drainage Area Length Y, Feet - Enter the length corresponding to length Y in Figure 1. This is the total length of the drainage area in the Y-direction.

4. Well Location x, Feet - Enter the distance corresponding to location x in Figure 1. This is the x-component of the wellbore location within the drainage area.

5. Well Location y, Feet - Enter the distance corresponding to location-y in Figure 1. This is the y-component of the wellbore location within the drainage area.

Line 220 (Flowstream Data)

	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (Inches)	Liquid Comp. (V/MMV/PSI)
220	1.995	0	9750	0	3.8

This line must always be present in a data file. The items are described as follows:

1. Flowstream O. D., Inches - Enter the outer diameter of the producing fluid stream within the wellbore. For tubing flow this entry will be the tubing I. D. For annular flow this entry will be the casing I. D. If wellbore pressure losses are not being considered, enter a zero.

2. Flowstream I. D., Inches - Enter the inner diameter of the producing fluid Stream. This entry only applies to annular flow and corresponds to the O. D. of the tubing. For tubing flow enter a zero for this item. If wellbore pressure losses are not being considered, enter a zero.

3. Zone Depth, Feet - Enter the depth to the mid-point of the producing interval. If wellbore pressure losses are not being considered, enter a zero.

4. Pipe Roughness, Inches - Specify the absolute pipe roughness in inches. If a zero is entered the program will use a default value of 0.0018 inches in the wellbore hydraulics calculations.

5. Liquid Comp., V/MMV/PSI - This compressibility should reflect that part of the total system compressibility not accounted for by the gas compressibility. This entry is -

$$C = S_l C_l + C_f$$

where,

S_l = liquid saturation, percent

C_l = actual liquid compressibility, V/MM/PSI

C_f = formation compressibility, V/MMV/PSI

The importance of this entry depends on the magnitude of the gas compressibility. If the gas compressibility is large, this item will not significantly affect the calculations.

Line 230 (Fluid Data)

	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230	.68	.93	.12	1.0	0

This line is required in all input data files. The entries are described as follows:

1. Gas Gravity, (Air=1) - Enter the specific gravity of the gas.

2. Liquid Gravity, (Water=1) - Enter the specific gravity of the liquid. If the liquid consists of both condensate and water, enter a weighted specific gravity based on the proportion of each liquid in the produced stream. If no liquid is present in the flowstream, enter a zero.

3. H2S Diluent, Mol % - Enter the hydrogen sulfide content of the produced gas. When used, values for N_2 and CO_2 should also be entered.

4. CO2 Diluent, Mol % - Enter the carbon dioxide content of the produced gas. When used, values for H_2S and CO_2 should also be entered.

5. N2 Diluent, Mol % - Enter the nitrogen content of the produced gas.

Line 240 (Optional Data)

	Non-Darcy Flow[3] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
240	0	0	1	14.025	60

The use of this line is optional. The entries are described as follows:

1. Non-Darcy Flow Coefficient, Days/MCF - This entry enables the user to introduce a rate-dependent dimensionless pressure drop into the calculations. This is normally done when it has been observed that the skin factor is rate-dependent. The coefficient represented here is the slope of a plot of skin factor versus producing rate.

2. Skin Factor, Dimensionless - This entry is sometimes used to approximate the increased flow efficiency of a fracture by a skin factor. This should only be done when a wellbore radius has been entered on line 210. If a fracture length has been entered on line 210, this entry will normally be zero.

3. Fracture Type - Enter a zero for an infinite conductivity fracture. Enter a 1 for a uniform flux fracture. If line 240 is not being used, the program will default to use of an infinite conductivity fracture.

4. Standard Pressure, PSIA - Enter the standard pressure. If no entry is supplied the program will assume a value of 14.65 psia.

5. Standard Temperature, Degrees F - Enter the standard temperature. If no entry is supplied the program will assume a value of 60 degrees F.

Line 700 (Initial Time and Pressure)

	Beginning Date[6] Mo.	Day	Year	Initial Reservoir, PSIG	Minimum[7] Rate MCF/D
700	1	1	79	3975	1

Line 700 is required. The entires are described as follows:

1. Beginning Date, Month-Day-Year - This entry establishes the beginning time of the run. The reservoir pressure at this time should be uniform throughout the drainage area.

2. Initial Reservoir Pressure, PSIG - Enter the reservoir pressure corresponding to the beginning rate.

3. Minimum Rate, MCF/D - Specify a rate which will serve as a cutoff for the calculations. This rate may be regarded as the economic limit for the well. This value may be negative, which can be useful in preventing the calculations from stopping during a comparison run when the user is trying to match very low rates (or zero rates in the case of a build-up test).

Line 701-799(Limiting Data)

	Limiting Date[6] Mo.	Day	Year	Limiting Wellhead Flow, PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701	1	1	80	900	3000	5.7	90
702	6	1	81	300	3000	9	90
703	1	1	83	300	3000	16	90

These lines are used to supply the program with information to govern the producing conditions. The information is time-scheduled as described below:

1. Limiting Date, Month-Day-Year - This entry supplies the time through which the subsequent information on the line will apply. The first date supplied here must be later than the beginning date specified on line 700. Note: The day can be entered as a decimal fraction for instances where limiting values change within the span of a day.

2. Limiting Wellhead Flowing Pressure, PSIG - This entry represents the minimum permissible wellhead pressure. If the well rate is restricted, due to an allowable for example, the calculated wellhead pressure will always be higher than this input value. If the well is producing at maximum capacity the wellhead pressure will be maintained at the specified value as the rate declines. If observed data is being entered for comparison purposes, enter the observed wellhead pressure.

3. Limiting Gas Rate, MCF/D - This entry represents the maximum permissible gas production rate. The well will be limited to this rate even if flow capacity against the limiting wellhead pressure is greater. If observed data is being entered for comparison purposes, enter the observed producing rate.

4. Liquid Rate, Bbls./MMCF - The program will adjust the wellbore hydraulics calculations to account for the presence of liquids in the flowstream. It it is desired to increase the wellbore pressure gradient to account for liquids, enter the total liquid rate in Bbls./MMCF. Otherwise, enter a zero.

5. Wellhead Temperature, Degrees F - Enter the wellhead flowing temperature.

Up to 99 lines of limiting data may be included in a single file.

RUNNING THE PROGRAM

Setting Up an Input Data File

The user must place his input data into a timesharing file prior to running program GASWELL. Data for only one case may be placed in a single file.

Program Operation and Output

There are basically four ways GASWELL can be run:

1. As a prediction with future production constraints specified on lines 701-799 in the input data file.

2. As a prediction with future production constraints specified interactively on the terminal during execution.

3. As a comparison of computed to observed wellhead pressures given specified producing rates, with the tests input on lines 701-799.

4. As a comparison of computed to observed producing rates given specified wellhead pressures, with these tests input on lines 701-799.

Since each of these methods requires slightly different procedures to run, the following examples were prepared (one for each of the four methods above) to illustrate the dialogue required to use these methods and the resulting output for each. Comments with respect to the circled numbers are as indicated below.

In all cases these output reports are located in user-named output files and can be listed on the terminal after execution of the program.

Every GASWELL execution will generate two pages of output. The first output page will be the same regardless of which type run is being made. For this reason page one will be discussed first and omitted from the individual examples.

1. The first three lines printed in the upper left-hand corner are the information contained on input data lines 101-103.

2. The following items appear under the heading "Reservoir Properties":

   a) Date - The date on the 700-line of the input data. This is the initial time-zero date.

   b) Pressure, Psig - The input reservoir pressure at the initial date. This pressure is assumed to be uniform throughout the drainage area.

GENERAL PAGE ONE EXAMPLE
OUTPUT FOR EACH GASWELL (1)
CALCULATION MADE

1/26/79 10:25:00

F R A C T U R E D G A S W E L L

P R O D U C T I O N P E R F O R M A N C E

RESERVOIR PROPERTIES (2)

DATE	12-31.00-78	LIQUID SAT., PCT.	40.0
PRESSURE, PSIG	3000.0	TEMPERATURE, DEG. F.	200.0
PERMEABILITY, MD.	1.000	TOTAL COMP., V/MMV/PSI	176.9
POROSITY	25.0	NON-DARCY FLOW COEFF.	0.0
NET PAY, FT.	50.0	SKIN	0.0

RESERVOIR GEOMETRY (3)

FRACTURE LENGTH, FT.	400.0	FRACTURE TYPE	I.C.
X-LENGTH, FT.	2640.	X-LOCATION, FT.	1320.
Y-LENGTH, FT.	2640.	Y-LOCATION, FT.	1320.

FLUID PROPERTIES (4)

GAS GRAVITY	0.600	H2S, MOL. PCT.	0.00
LIQUID GRAVITY	0.000	CO2, MOL. PCT.	0.00
STANDARD PRESSURE, PSIA	14.65	N2, MOL. PCT.	0.00
STANDARD TEMP., DEG. F.	60.0		

FLOWSTREAM DATA (5)

FLOWSTREAM O.D., IN.	1.995	TOTAL DEPTH, FT.	7000.
FLOWSTREAM I.D., IN.	0.000	ABS. PIPE ROUGH., IN.	0.00180

c) Permeability, Md. - The input reservoir matrix permeability.

d) Porosity, % - The input reservoir matrix porosity.

e) Net Pay, Ft. - Input net pay in the producing interval.

f) Liquid Saturation, % - Combined input hydrocarbon and water saturation in the drainage area.

g) Temperature, Degrees F - The average input reservoir temperature.

h) Total Compressibility, V/MMV/PSI - The computed total compressibility at initial reservoir conditions.

i) Non-Darcy Flow Coefficient - The input non-Darcy flow coefficient. Units are MM Days/Mcf.

j) Skin - The input skin factor.

3. The following items appear under the heading "Reservoir Geometry":

a) Fracture Length, Ft. - The input tip-to-tip fracture length. If a fracture is not being used, this item will be shown as a wellbore radius.

b) X-length, Ft. - The drainage area X length input on line 210.

c) Y-Length, Ft. - The drainage area Y length input on line 210.

d) Fracture Type - The input fracture type will be printed as "I.C." for infinite conductivity fractures and "U.F." for uniform flux fractures.

e) X-Location Ft. - The wellbore x location input on line 210.

f) Y-Location, Ft. - The wellbore y location input on line 210.

4. The following items appear under the heading "Fluid Properties":

a) Gas Gravity - The input gas specific gravity (Air=1.0).

b) Liquid Gravity - The input liquid specific gravity (Water=1.0).

c) Standard Pressure - The input standard pressure, psia.

d) Standard Temperature, Degrees F - The input standard temperature.

e) H2S, CO2, N2, Mol. Percent - The input mol percentage of diluents.

5. The following items follow the heading "Flowstream Data":

a) Flowstream O.D., Inches - The input O.D. of the flowstream. This will be the tubing I.D. for tubing flow, or the casing I.D. for annular flow.

b) Flowstream I.D., Inches - The input I.D. of the flowstream. This will be 0 for tubing flow, or the tubing O.D. for annular flow.

c) Total Depth, Ft. - The input depth to the mid-point of the producing interval.

d) Absolute Pipe Roughness, In. - The input absolute pipe roughness.

Example 1
Production Forecast

In this example the user wishes to predict the performance of the well and has scheduled all future production constraints by using lines 701-799 in the input data file. The execution dialogue is presented first, followed by the second page of the output report.

```
RUN GASWELL (1)
GASWEL @ 10:56:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX1 XX1OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?0 (3)


 ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
 OUTPUT TIME INTERVALS (MOS.) --?1 1 79 12 (4)


 WANT TO ALTER INPUT DATA --?YES (5)


 LINE, WORD, VALUE --?701 4 1000


 LINE, WORD, VALUE --?0 0 0


 WANT TO ALTER INPUT DATA --?NO

 FILE - XX1OUT    SAVED. (6)
 READY.
```

1. This command retrieves the GASWELL program from the GCS library and places it in execution.

2. The input file is the file which has been previously prepared and contains the input data for the program. The output file contains the reports generated by the program. The P-code refers to the type terminal on which the output reports are to be printed. Permissible P-codes and their meanings are as follows:

   1 - Teletypes, Terminets, TI Silent700's and others that do not have form-feeding capabilities and thereby must rely on the counting of lines to establish 11-inch pages.

   2 - DCT 500's, DECwriters, paging Terminets, Beta's and similar form-feeding, wide-carriage terminals.

   3 - Conventional line printers that require a numeric "1" in the first column for top-of-form.

3. If a production forecast (predictive run) is desired, a zero is entered in response to the program's question concerning the type of run.

4. For predictive runs the program will request a starting output date and the number of months between output lines. The starting date will normally be the first date on which output is desired. This date must be later than the date specified on line 700 of the input data form. The number of months between output lines enables the user to schedule production monthly, quarterly, etc. The maximum number of months allowed between output lines is 12.

5. When the calculations are complete the program will ask the question "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the run recomputed. The program will ask for:

   a) The line number of the input data line on which a change is wanted.

   b) The position of the data item on the line.

   c) The new data value to be inserted.

   Using this method, any number of data items can be changed. Three zeros are used to indicate that the OVER sequence should terminate and the new run should begin. In this example the user is changing the fourth value on line 701 to 1000 (reducing the input line pressure from its original value of 1500 psi to 1000 psi).

6. This indicates that the file containing the output report has been saved.

The second page of the report for each run made in Example 1 is shown on the opposite page. Notice that the first run reflects the projection for the well against a 1500 psi line pressure, while the second run illustrates the improvement expected due to a lower line pressure of 1000 psi (subject to a maximum well rate of 10,000 Mcf/D).

7. The first three lines printed in the upper left-hand corner contain the information input on lines 101-103.

8. The following items appear under the heading "Predicted Performance":

   a) Month-Day-Yr - The date for which the following items on the output line apply. The dates for output are governed either by the terminal response to the question asking for an output schedule or the dates on the 701-series lines.

   b) Flowing WHP, Psig - The flowing wellhead pressure. This pressure will either be the minimum specified wellhead pressure or a computed wellhead pressure, depending upon whether the well is producing at the maximum allowed rate.

   c) Flowing BHP, Psig - The flowing bottom-hole pressure at the producing depth.

   d) Avg. S.I. BHP, Psig - The average reservoir pressure at the specified date.

   e) Gas Rate, M/D - The average gas rate for the preceding output interval. Note that this value is not the well rate for the date printed at the left.

   f) Cum. Gas, BCF - Cumulative gas production.

   g) Cum. Rec., Pct. - Cumulative percent recovery of the initial gas-in-place.

   h) Z-Factor - The reservoir Z-factor at the average reservoir pressure and average reservoir temperature.

EXAMPLE NUMBER 1 (7)
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(8) P R E D I C T E D P E R F O R M A N C E

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1500.0	2657.6	2996.4	9774.	0.0098	0.10	0.9072
1- 1.000-80	1500.0	1907.4	2378.0	4986.	1.8296	19.59	0.8956
1- 1.000-81	1500.0	1791.2	2064.1	2716.	2.8237	30.23	0.8968
1- 1.000-82	1500.0	1754.5	1902.9	1431.	3.3462	35.83	0.8994
1- 1.000-83	1500.0	1744.5	1821.0	735.	3.6144	38.70	0.9013
1- 1.000-84	1500.0	1741.9	1780.1	366.	3.7480	40.13	0.9023
1- 1.000-85	1500.0	1741.2	1760.4	176.	3.8122	40.82	0.9027
1- 1.000-86	1500.0	1741.2	1751.5	79.	3.8411	41.13	0.9029
1- 1.000-87	1500.0	1740.9	1745.5	54.	3.8607	41.34	0.9031
1- 1.000-88	1500.0	1741.3	1743.5	17.	3.8670	41.40	0.9031
1- 1.000-89	1500.0	1741.0	1742.3	11.	3.8711	41.45	0.9031

Report Resulting from Original Data
(Page 2)

EXAMPLE NUMBER 1
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(8) P R E D I C T E D P E R F O R M A N C E

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1383.0	2645.1	2996.3	10000.	0.0100	0.11	0.9072
1- 1.000-80	1000.0	1553.0	2230.5	6265.	2.2968	24.59	0.8962
1- 1.000-81	1000.0	1319.1	1800.3	3784.	3.6818	39.42	0.9018
1- 1.000-82	1000.0	1218.5	1543.9	2309.	4.5246	48.44	0.9099
1- 1.000-83	1000.0	1179.0	1388.0	1401.	5.0361	53.92	0.9162
1- 1.000-84	1000.0	1163.9	1293.8	839.	5.3425	57.20	0.9202
1- 1.000-85	1000.0	1158.2	1237.9	495.	5.5237	59.14	0.9227
1- 1.000-86	1000.0	1156.4	1205.7	284.	5.6274	60.25	0.9241
1- 1.000-87	1000.0	1155.8	1184.4	188.	5.6962	60.99	0.9251
1- 1.000-88	1000.0	1155.1	1172.8	102.	5.7334	61.39	0.9256
1- 1.000-89	1000.0	1155.6	1165.7	63.	5.7563	61.63	0.9259

Report Resulting from Data as Modified
in Response to "WANT TO ALTER INPUT DATA--?"
(Page 2)

Example 2
Production Forecast - Interactive

This example illustrates use of the program in the predictive mode when the user desires to control the production constraints at the terminal while the program is executing. This mode of execution can be invoked by not including any of the 701-799 lines in the input data file. The program will then ask for the production constraints interactively.

1-3 Same as Example 1.

4. Same as Example 1. Here the user is requesting quarterly output.

5. Since no 701-799 lines have been included in the input data file the program asks the user for information that would normally be supplied on those lines. The program will then proceed to compute results until the date supplied as the first item has been reached.

6. When the interactive mode of execution is being used, a recap of the predicted performance is printed on the terminal until the last supplied time has been reached. This enables the user to monitor the progress of the calculations.

7. Three responses to the "MORE--?" question are valid: NO, OVER, and YES.

   NO - This response causes the run to terminate.

   OVER - This response allows the user to change his input data for a new run. The use of this response is exactly the same as illustrated in Example 1 where "YES" is answered to the question "WANT TO ALTER INPUT DATA--?".

   YES - This response indicates that the interactive run is to continue with a new set of production constraints.

8. Following an "OVER" or "YES" response, the program does not allow the user to change the output schedule. It proceeds directly to the question asking for a set of production constraints. Here the user is requesting another year of output with the same line pressure as before.

9. The predicted performance for the new run is printed.

10. The "NO" response to the "MORE--?" question terminates the calculations.

11. The program indicates the output file containing the complete report has been saved. The output file in this case will contain one report for both the original run and the subsequent run. The information will be exactly the same as the recaps shown on the dialogue page, but the output will be continuous, that is all nine lines of projections will appear under one set of headings.

```
RUN GASWELL
 GASWEL @ 10:53:00 ON  1/29/79 (1)


 INPUT FILE,OUTPUT FILE, & P CODE --?XX2 XX20U1 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?0 (3)


 ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
 OUTPUT TIME INTERVALS (MOS.) --?1 1 79 3 (4)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 80 1500 5000 0 100 (5)

                  FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR      WHP        BHP        SI BHP     RATE       GAS        REC.      Z FAC. (6)
------------      PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---    ------

  1- 1.000-79      2254.0     2825.6     2998.1     5000.      0.0050      0.05    0.9073
  4- 1.000-79      1741.3     2281.7     2832.2     5000.      0.4550      4.87    0.9007
  7- 1.000-79      1550.6     2087.1     2667.5     5000.      0.9100      9.74    0.8945
 10- 1.000-79      1500.0     1983.2     2530.8     4721.      1.3444     14.39    0.8950
  1- 1.000-80      1500.0     1925.7     2412.3     4089.      1.7205     18.42    0.8955


 MORE --?YES (7)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 81 1500 5000 0 100 (8)

                  FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR      WHP        BHP        SI BHP     RATE       GAS        REC.      Z FAC. (9)
------------      PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---    ------

  4- 1.000-80      1500.0     1880.4     2310.2     3534.      2.0422     21.87    0.8959
  7- 1.000-80      1500.0     1845.4     2223.4     3046.      2.3194     24.83    0.8962
 10- 1.000-80      1500.0     1818.2     2147.5     2613.      2.5597     27.41    0.8965
  1- 1.000-81      1500.0     1797.9     2082.7     2230.      2.7649     29.60    0.8967


 MORE --?NO (10)


 FILE - XX2OUT    SAVED. (11)
 READY.
```

Example 3
Comparison with Observed Data

This example illustrates use of the program to compare observed production history with computed results. This comparison will be on the basis of wellhead pressure.

As discussed previously, when comparisons are being performed the observed data should be entered in chronological sequence on the 701-799 lines on the input data form. For a comparison based on wellhead pressure the program will force the well to produce at the input rates and compute the corresponding wellhead pressures. The computed pressures will not be affected in any way by the input pressures. A report showing the comparison will then be produced.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on wellhead pressure.

4. When comparison runs are being performed, a table is printed on the terminal which shows the test times along with computed and observed values. In this example the observed and calculated rates are shown to be the same since only wellhead pressures are actually being computed. The observed pressure will be the test pressure which is tabulated along with the computed pressure.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated wellhead pressures are too low so the user increases the permeability (input as the first word on line 200) to one millidarcy in an attempt to get a better history match. The second table shows a good match on pressure so the run is terminated.

6. The program indicates that the file containing the output has been saved.

The second page of the output report will show the same information contained in the table that appears on the terminal during execution, but with the addition of three lines of heading information and a title, "PERFORMANCE COMPARISON". In this example, four pages of output would result; a first and second page for the original run, and a first and second page for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:51:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX3 XX3OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?1 (3)

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D----

  1- 1.000-78        1500.0     1394.9     9540.     9540.
  2- 1.000-78        1500.0     1202.5     6590.     6590.
  3- 1.000-78        1500.0     1151.4     6160.     6160. (4)
  7- 1.000-78        1500.0     1180.4     5040.     5040.
  1- 1.000-79        1500.0     1259.1     3910.     3910.


 WANT TO ALTER INPUT DATA --?YES (5)


 LINE, WORD, VALUE --?200 1 1


 LINE, WORD, VALUE --?0 0 0

                    OBSERVED   CALC.      OBSERVD   CALC.
 MONTH-DAY-YR       WHP        WHP        RATE      RATE
 ------------       PSIG----   PSIG----   M/D----   M/D-----

  1- 1.000-78        1500.0     1507.5     9540.     9540.
  2- 1.000-78        1500.0     1518.5     6590.     6590.
  3- 1.000-78        1500.0     1510.4     6160.     6160.
  7- 1.000-78        1500.0     1502.0     5040.     5040.
  1- 1.000-79        1500.0     1497.8     3910.     3910.


 WANT TO ALTER INPUT DATA --?NO

FILE - XX3OUT    SAVED. (6)
READY.
```

Example 4
Comparison with Observed Data

This example illustrates the use of the program when comparing computed rates to observed values. In this case the program is forced to produce at the wellhead pressures entered on the 701-799 lines. The corresponding computed rates can then be compared to the observed rates.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on rate.

4. As with the comparison in the prior example, times along with observed and calculated values are tabulated at the user's terminal. In this case the observed and calculated pressures are identical, with the variance between the observed and computed rates being illustrated.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated rates are too high, so the user reduces the fracture length (input as the first word on line 210) to 400 feet. A good match on producing rates results so the run is terminated.

6. The program indicates that the file containing the output report has been saved. As in the previous example, the output will consist of four pages -- one two-page set for the original run and another two-page set for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:41:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX4 XX4OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?2 (3)

                    OBSERVED   CALC.      OBSERVD    CALC.
 MONTH-DAY-YR       WHP        WHP        RATE       RATE
 ------------       PSIG----   PSIG----   M/D----    M/D----

  1- 1.000-78        1500.0     1500.0      9540.      9857.
  2- 1.000-78        1500.0     1500.0      6590.      6951.  (4)
  3- 1.000-78        1500.0     1500.0      6160.      6495.
  7- 1.000-78        1500.0     1500.0      5040.      5172.
 1-10.000-79         1500.0     1500.0      3545.      3670.


 WANT TO ALTER INPUT DATA --?YES (5)


 LINE, WORD, VALUE --?210 1 400


 LINE, WORD, VALUE --?0 0 0

                    OBSERVED   CALC.      OBSERVD    CALC.
 MONTH-DAY-YR       WHP        WHP        RATE       RATE
 ------------       PSIG----   PSIG----   M/D----    M/D----

  1- 1.000-78        1500.0     1500.0      9540.      9547.
  2- 1.000-78        1500.0     1500.0      6590.      6585.
  3- 1.000-78        1500.0     1500.0      6160.      6162.
  7- 1.000-78        1500.0     1500.0      5040.      4935.
 1-10.000-79         1500.0     1500.0      3545.      3557.


 WANT TO ALTER INPUT DATA --?NO


 FILE - XX4OUT    SAVED. (6)
 READY.
```

TECHNICAL NOTES

1. The procedures used in GASWELL to compute dimensionless pressure versus dimensionless time are based upon the following work: Gringarten, A. C., Ramey, H. J., Jr., and Ravhavan, R.: "Unsteady-State Pressure Distributions Created by a Well with a Single Infinite-Conductivity Vertical Fracture", Soc. Pet. Eng. J. (Aug. 1974) 347-360; AIME Trans., Vol. 257.

2. The constant-rate solutions from Gringarten, et. al. are converted to variable-rate solutions needed by GASWELL using superposition.

3. The average reservoir pressure is computed by subsequent time periods by material balance.

4. The pressure drop in the wellbore is calculated using the technique of Cullender and Smith.

GASWELL Simulator
Input Data Form
2/79

RUN DESCRIPTION:

Well Name & No.	101	
Field & Zone	102	
County & State	103	

RESERVOIR AND WELL DATA:

	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation, %	Temperature of Zone, °F
200					
	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210					
	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (Inches)	Liquid Comp. (V/MMV/PSI)
220					
	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230					
	Non-Darcy Flow[3] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
Optional 240					

TIME, PRESSURE & RATE DATA:

	Beginning Date[6] Mo. Day Year	Initial Reservoir, PSIG	Minimum[7] Rate MCF/D		
Required Line 700					
	Limiting Date[6] Mo. Day Year	Limiting Wellhead Flow, PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701					
702					
703					
704					
705					

Use lines 701-799 to enter limiting time, wellhead pressure & rates. If omitted, program will ask for limiting conditions.

NOTES:

(1) If value less than 1 foot entered, it will be used as the wellbore radius with no fracture.

(2) Distance measured from lower left corner of rectangular drainage area.

(3) Used to handle turbulence.

(4) Dimensionless pressure drop due to skin effects.

(5) Enter zero for infinite conductivity fracture. Enter 1 for uniform flux fracture.

(6) Fractional day number may be entered; for example, "7 9.25 77" would be 6 hours(.25 days) into the ninth day of July 1977.

(7) Calculations will stop when the specified rate is reached.

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Unsteady-State Pressure Distributions Created by a Well With a Single Infinite-Conductivity Vertical Fracture

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INTRODUCTION

During the last few years, there has been an explosion of information in the field of well-test analysis. Because of increased physical understanding of transient fluid flow, it is possible to analyze the entire pressure history of a well test, not just long-time data as in conventional analysis.[1] It is now often possible to specify the time of beginning of the correct semilog straight line and determine whether the correct straight line has been properly identified. It is also possible to identify wellbore storage effects, and the nature of wellbore stimulation as to permeability improvement, or fracturing, and to quantitatively analyze those effects.

Such accomplishments have been augmented by attempts to understand the short-time pressure data from well testing — data that were often classified as too complex for analysis. One recent study of short-time pressure behavior[2] showed that it was important to specify the physical nature of the stimulation in considering the behavior of a stimulated well. That is, stating that the van Everdingen-Hurst infinitesimal skin effect was negative was not sufficient to define short-time well behavior. For instance, acidized (but not acid-fractured) and hydraulically fractured wells might not necessarily exhibit the same behavior at early times, even though they could possess the same value of negative skin effect.

In the same manner, hydraulic fracturing leading to horizontal or vertical fractures could produce the same skin effect, but with possibly different short-time pressure data. This could then provide a way to determine the orientation of fractures created by this type of well stimulation. In fact, it is generally agreed that hydraulic fracturing usually results in one vertical fracture, the plane of which includes the wellbore. Most studies of the flow behavior for a fractured well consider vertical fractures only.[3-11]

Yet it is also agreed that horizontal fractures *could* occur in shallow formations. Furthermore, it would appear that notch-fracturing would lead to horizontal fractures. Surprisingly, no detailed study of the horizontal fracture case had been performed until recently.[12] A solution to this problem was presented by Gringarten and Ramey.[13] In the course of their study, it was found that a large variety of new transient pressure behavior solutions useful in well and reservoir analysis could be constructed from instantaneous Green's functions.[14] Possibilities included a well with a single vertical fracture in an infinite reservoir, or at any location in a rectangle.

Although similar cases had been studied before by van Everdingen and Meyer,[11] and by Russell and Truitt,[8] there were confusing differences in their respective results, and small inconsistencies between the cases of Ref. 8 made short-time analysis impossible. Both explicit and implicit finite-difference solutions and finite-element solutions were made for the vertical fracture case of Russell and Truitt in an attempt to eliminate differences between Refs. 8 and 11, and internal differences between cases in Ref. 8. It was not possible to reach satisfactory conclusions for the short-time performance region with even very long computer runs with *either* finite-difference or finite-element[12] programs. For this reason, it was decided to evaluate analytical solutions to provide a sound basis for short-time analysis of field data. In the course of the work, to provide a direct comparison with the Russell and Truitt data it became necessary to develop analytical solutions for fracture cases in which the fluid entry flux along the fracture caused a constant pressure along the fracture (infinite fracture conductivity). It also appeared worthwhile to evaluate the new solutions so that vertical fracture behavior could be compared with horizontal fracture behavior in infinite reservoirs. The new solutions for vertically fractured wells are especially useful for short-time or type-curve analysis. Such an analysis can provide information concerning permeabilities, fracture

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*Now with French Geological Bureau, Orleans, France.
**Now with Amoco Production Co., Tulsa, Okla.
[1]References listed at end of paper.

length, and distance to a symmetrical drainage limit. Combination of short-time analysis with older conventional semilog analytical methods permits an extraordinary confidence level concerning the analysis of field data.

VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

We model a plane (zero-thickness) vertical fracture totally penetrating a horizontal, homogeneous, and isotropic reservoir initially at constant pressure. At time zero, a single-phase, slightly compressible fluid flows from the reservoir into the fracture at a constant total rate. The producing pressure is *uniform* over the fracture (infinite fracture conductivity). The pressure remains constant and equal to the initial pressure as distance from the well becomes infinitely large (infinite reservoir).

An analytical expression for the pressure distribution created by the plane vertical fracture may be obtained by the Green's function and product solution method,[22] using source functions presented by Gringarten and Ramey.[14] The condition of uniform pressure over the fracture at all times is satisfied, as indicated in Ref. 14, by dividing the half-fracture length x_f into M segments of length x_f/M, each with a uniform flux per unit area, q_m, $(m = 1,M)$. The first segment extends from 0 to x_f/M, the second segment from x_f/M to $2x_f/M$, the mth segment from $[(m-1)x_f]/M$ to mx_f/M, and the last segment from $[(M-1)/M]x_f$ to x_f, as shown in Fig. 1. The q_m $(m = 1,M)$ are determined by equating the pressure drops at the center of the segments, which provide $(M-1)$ equations, the mth equation being obtained from the condition of constant total production rate at all times:

$$\begin{cases} \Delta p\left(\frac{2j-1}{2M}\, x_f,\ 0,\ t\right) = \Delta p\left(\frac{2j+1}{2M}\, x_f,\ 0,\ t\right) \quad j=1,M-1 \quad \ldots(1) \\ 2\sum_{m=1}^{M} q_m \left(\frac{x_f}{M}\right) h = q_f \quad \ldots\ldots(2) \end{cases}$$

The pressure drop created by the fracture is obtained from Ref. 14, Table 5:

$$p_i - p_{x,y,t} = \frac{1}{\phi c} \int_0^t \left\{ \sum_{m=1}^{M} q_m(\tau) \int_{\frac{(m-1)x_f}{M}}^{\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2 + y^2}{4\eta(t-\tau)}\right] dx_w - \sum_{m=1}^{M} q_m(\tau) \int_{-\frac{(m-1)}{M}x_f}^{-\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2 + y^2}{4\eta(t-\tau)}\right] dx_w \right\} \cdot \frac{d\tau}{4\pi\eta(t-\tau)} \quad \ldots\ldots(3)$$

The coordinate system in Fig. 1 and Eq. 3 is different from that of Ref. 14, however. A similar scheme has been used by Muskat[15] for the steady-state pressure distribution created by a partially penetrating well, and has been suggested by Burns[16] for unsteady state. In the unsteady state, however, the method seems impractical: it was expected — and confirmed from a numerical simulation[21] — that the flux per unit area of fracture is not constant but varies in time. A system of M equations and M unknowns as represented by Eqs. 1 and 2 should thus be solved at each value of time.

Actually, this is not true practically, and the pressure distribution can be obtained by solving the system of equations only once. The flux distribution in the fracture at various times, as obtained from a numerical simulation, is shown in Fig. 2. It can be seen that the flux distribution is uniform at very early times, then it changes, and finally it reaches a steady state at some extended time, after which flow entering the fracture stabilizes. The pressure during the stabilized flow period is independent of the flux distribution history, and is the same as if the flux distribution had been equal to the final stabilized flux distribution at all times.

An analog to this interesting and useful fact

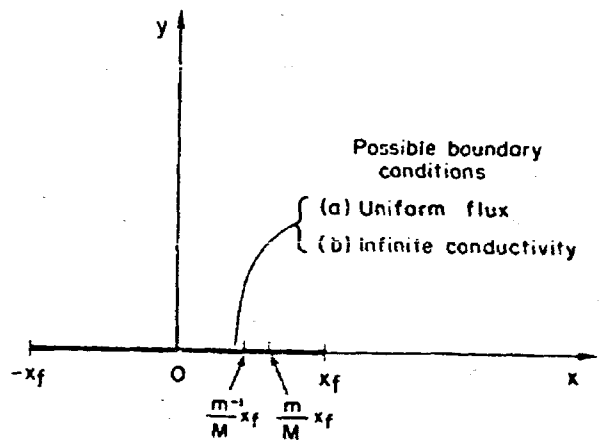

FIG. 1 — VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

occurs in the case of flow to a constant-rate well with wellbore storage. Wellbore storage causes the sand-face production rate to change as a function of time initially. But after some initial period, the sand-face rate reaches the constant surface rate (within a specified percentage), and thereafter the producing pressure is equal to that of a well whose sand-face rate had been constant from the start of production. The pressure is independent of the production history! The same sort of observation was made in another reservoir problem by Carter and Tracy.[23]

By solving the system of Eqs. 1 and 2 for the *stabilized flux distribution* one can obtain a long-time solution for the pressure, whereas an early-time solution can be obtained by assuming uniform flux. We shall show that these also provide an excellent approximation for the pressure distribution at all times.

EARLY-TIME SOLUTION

Integrating Eq. 3 with respect to x_w, the dimensionless pressure drop can be written as

$$p_D(x_D,y_D,t_D) = \int_0^{t_D} \exp -\frac{y_D^2}{4(t-t')_D} \sum_{m=1}^{M} \left(\frac{2q_m(t'_D)hx_f}{q_f}\right) \left[\operatorname{erf} \frac{x_D + \frac{m}{M}}{\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D + \frac{m-1}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D - \frac{m}{M}}{2\sqrt{(t-t')_D}} + \operatorname{erf} \frac{x_D - \frac{m-1}{M}}{2\sqrt{(t-t')_D}}\right] \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

The dimensionless space and time variables in Eq. 4 are based on the fracture half-length x_f,

$$x_D = \frac{x}{x_f} \; ; \quad y_D = \frac{y}{x_f} , \quad \ldots\ldots\ldots (5)$$

and the dimensionless time and the dimensionless pressure drop are, respectively,

$$t_D = \frac{kt}{\phi\mu c x_f^2} , \quad \ldots\ldots\ldots\ldots\ldots (6)$$

and

$$p_D(x_D,y_D,t_D) = \frac{2\pi kh}{q_f\mu} (p_i - p_{x,y,t}) . \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

At very early times, the expression

$$\operatorname{erf} \frac{x_D \pm \frac{m}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf} \frac{x_D \pm \frac{m-1}{M}}{2\sqrt{(t-t')_D}}$$

becomes constant when t_D is small enough.[14] (The constant is 2 if $(m-1)/M < |x_D| < m/M$; unity if $x_D = (m-1)/M$ or $|x_D| = m/M$; and zero if $x_D < (m-1)/M$ or $|x_D| > m/M$.) Therefore, at very early times the system given by Eqs. 1 and 2 reduces to

$$\begin{cases} \displaystyle\int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \frac{2q_j(t'_D)hx_f}{q_f} \cdot \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}} = \int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \cdot \frac{2q_{j+1}(t'_D)hx_f}{q_f} \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}}, \\ \qquad j=1,\ M-1 \quad \ldots\ldots\ldots (8) \\ \displaystyle\sum_{m=1}^{M} \frac{2q_m(t_D)hx_f}{q_f} = M, \quad \text{all } t_D , \quad \ldots\ldots\ldots (9) \end{cases}$$

which yields

$$q_j = \frac{q_t}{2hx_f} , \quad j=1,M$$

As indicated by the numerical model, the flux must be uniform over the fracture at very early times, and the early-time solution for the pressure drop function is

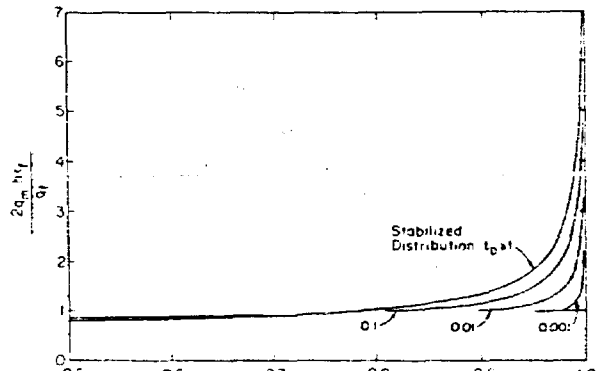

FIG. 2 — FLUX DISTRIBUTION AT VARIOUS TIMES ALONG AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE (NUMERICAL MODEL).

$$p_D(|x_D|<1, y_D, t_D) = \int_0^{t_D} \exp\left(-\frac{y_D^2}{4t'_D}\right) \frac{dt'_D}{2(t'_D/\pi)^{1/2}}$$

$$= (\pi t_D)^{\frac{1}{2}} \exp(-y_D^2/4t_D) - |y_D| \operatorname{erfc}(|y_D|/2\sqrt{t_D}) \quad \ldots (10)$$

$$p_D(|x_D|>1, y_D, t_D) = 0$$

and, along the fracture,

$$p_{wD}(|x_D|<1, 0, t_D) = \sqrt{\pi t_D}, \quad \ldots (11)$$

which is the conventional result for flow in a linear system. In this case, there is flow into both sides of the fracture.

LONG-TIME SOLUTION

During the stabilized flow period, the q_m's are constant and can be taken out of the integral sign in Eq. 3. Inverting the order of integration in Eq. 3, one obtains

$$p_D(x_D, y_D, t_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} \left\{ \int_{\frac{m-1}{M}}^{\frac{m}{M}} -\mathrm{Ei}\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] dx_{wD} - \int_{\frac{m-1}{M}}^{\frac{m}{M}} -\mathrm{Ei}\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] \cdot dx_{wD} \right\}, \quad \ldots (12)$$

with

$$\sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} = M \quad \ldots (13)$$

Substituting the series expansion of the exponential integral function into Eq. 12 yields the long-time solution for the dimensionless pressure drop function:

$$p_D(x_D, y_D, t_D) = \frac{1}{2}(\ln t_D + 2.80907) + \sigma(x_D, y_D), \quad \ldots (14)^*$$

where $\sigma(x_D, y_D)$ is a *pseudo skin function* that depends upon the position of the pressure point only:

$$\sigma(x_D, y_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} \cdot \left\{ (x_D - \tfrac{m}{M}) \ln[y_D^2 + (x_D - \tfrac{m}{M})^2] - (x_D + \tfrac{m}{M}) \ln[y_D^2 + (x_D + \tfrac{m}{M})^2] + (x_D + \tfrac{m-1}{M}) \ln[y_D^2 + (x_D + \tfrac{m-1}{M})^2] - (x_D - \tfrac{m-1}{M}) \ln[y_D^2 + (x_D - \tfrac{m-1}{M})^2] - 2y_D \arctan\left[\frac{2y_D}{r_D^2 + \frac{m(m-1)}{M^2}} \Big/ \left([r_D^2 - (\tfrac{m}{M})^2][r_D^2 - (\tfrac{m-1}{M})^2] + \frac{4m(m-1)}{M^2} y_D^2\right)\right] \right\} \quad \ldots (15)$$

where $r_D = r/x_f$ is the dimensionless distance to the axis of the fracture.

Eq. 14 has a form similar to the long-time approximation of the pressure function for radial flow[17] (i.e., a circular well without a fracture):

$$\frac{2\pi kh}{q\mu}(p_i - p_{r,t}) = \frac{1}{2}\left(\ln \frac{kt}{\phi \mu c r^2} + 0.80907\right), \quad r \geq r_w. \quad \ldots (16)$$

As in the radial flow case, a straight line of slope 1.1515 per logarithmic cycle is obtained when the long-time dimensionless pressure drop is plotted vs the dimensionless flowing time on semilog coordinates. Thus, well test analysis methods developed for transient *radial* flow problems and based upon the existence of the 1.1515 slope semilog straight line, can be extended to analyze transient flow into a vertically fractured well in an infinite system. Actually, it can be shown that Eq. 14 becomes identical with Eq. 16 if x_f

*"2.80907" is correct.

tends to zero, of if r becomes very large.

The q_m's $(m=1,M)$ in Eq. 15 are obtained by solving the system of equations represented by Eqs. 1 and 2, which now reduces to

$$\begin{cases} \sigma\left(\frac{2j-1}{2M},\ 0\right) = \sigma\left(\frac{2j+1}{2M},\ 0\right) \\ \qquad j = 1,M-1 \quad \ldots\ldots (17) \\ \sum_{m=1}^{M} \frac{2q_m hx_f}{q_f} = M \quad \ldots\ldots (18) \end{cases}$$

UNIFORM FLUX VERTICAL FRACTURE

This case corresponds to M = 1 and represents a first approximation of the behavior of a vertically fractured well. At early times, however, it is the exact solution.

The corresponding form of Eq. 4 is

$$p_D(x_D,y_D,t_D) = \int_0^{t_D} \exp\left(-\frac{y_D^2}{4t'_D}\right) \cdot \left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t'_D}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t'_D}}\right] \frac{dt'_D}{4\,(t'_D/\pi)^{1/2}} \quad \ldots\ldots (19)$$

Eq. 19 cannot be expressed in terms of tabulated functions, and must be evaluated with a computer, except in the plane of the fracture ($y_D = 0$), where it becomes

$$p_D(x_D,0,t_D) = \frac{1}{2}(\pi t_D)^{1/2}\left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t_D}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t_D}}\right] - \frac{(1-x_D)}{4}\operatorname{Ei}\left[-\frac{(1-x_D)^2}{4t_D}\right] - \frac{(1+x_D)}{4}\operatorname{Ei}\left[-\frac{(1+x_D)^2}{4t_D}\right] \quad \ldots\ldots (20)$$

Eq. 20 shows that pressure will vary along the fracture length (except at early times), which would not be true if the fracture had infinite conductivity. However, the pressure drop along the fracture is low, and the uniform flux condition gives the appearance of a high, but not infinite, fracture conductivity. Some field data appear to match this solution better than the infinite-conductivity solution.

One useful expression for well test analysis is the pressure drop on the axis of the fracture ($x_D = 0$, $t_D > 0$):

$$p_{wD}(t_D) = \sqrt{\pi t_D}\ \operatorname{erf}\left(\frac{1}{2\sqrt{t_D}}\right) - \frac{1}{2}\operatorname{Ei}\left(-\frac{1}{4t_D}\right) \quad \ldots\ldots (21)$$

$p_{wD}(t_D)$ has been listed vs t_D in Table 1, and plotted in Figs. 3 and 4 as the $(x_e/x_f = \infty)$ curve.

Approximating forms of Eq. 19 at small and large values of time are the same as obtained in the previous section. The sigma pseudo skin function for the long-time approximation, Eq. 15, simplifies to

$$\sigma(x_D,y_D) = \frac{1}{4}\left\{(x_D-1)\ln[y_D^2+(x_D-1)^2] - (x_D+1)\ln[y_D^2+(x_D+1)^2] - 2y_D \arctan\frac{2y_D}{r_D^2-1}\right\} \quad \ldots\ldots (22)$$

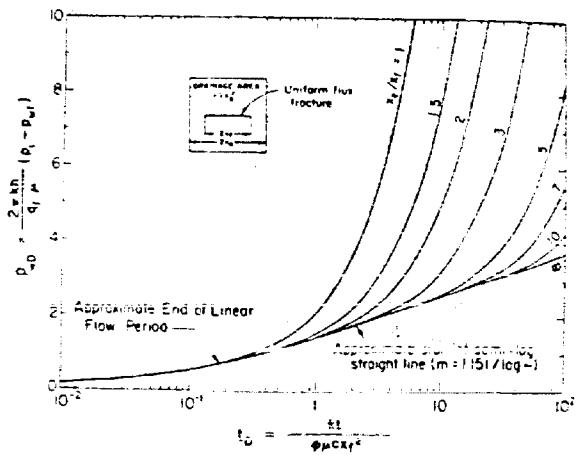

FIG. 3—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

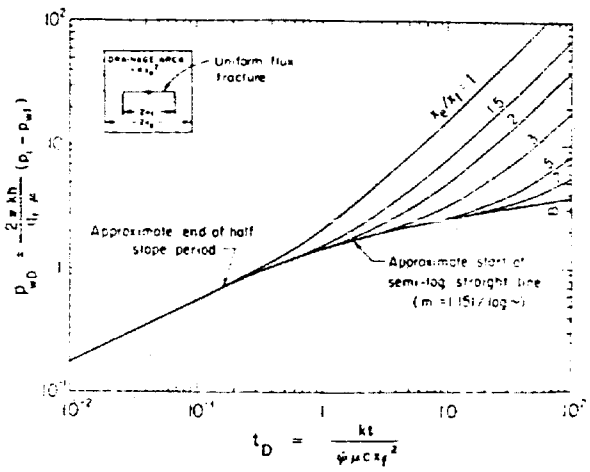

FIG. 4—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

and in the plane of the fracture,

$$\sigma_D(x_D,0) = -\frac{1}{2}\left[(1-x_D)\ln|1-x_D| + (1+x_D)\ln|1+x_D|\right] \quad \ldots (23)$$

TABLE 1 — p_{wD} FOR A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

t_D	Uniform flux	Infinite Conductivity
1.0E-02	0.1772	0.1765
1.5E-02	0.2171	0.2145
2.0E-02	0.2507	0.2456
3.0E-02	0.3070	0.2955
4.0E-02	0.3545	0.3356
5.0E-02	0.3963	0.3697
6.0E-02	0.4340	0.3996
8.0E-02	0.5007	0.4509
1.0E-01	0.5587	0.4945
1.5E-01	0.6790	0.5833
2.0E-01	0.7756	0.6549
3.0E-01	0.9261	0.7691
4.0E-01	1.0417	0.8603
5.0E-01	1.1355	0.9367
6.0E-01	1.2145	1.0027
8.0E-01	1.3427	1.1129
1.0E+00	1.4447	1.2030
1.5E+00	1.6344	1.3754
2.0E+00	1.7716	1.5032
3.0E+00	1.9676	1.6894
4.0E+00	2.1080	1.8248
5.0E+00	2.2175	1.9312
6.0E+00	2.3073	2.0189
8.0E+00	2.4494	2.1583
1.0E+01	2.5600	2.2673
1.5E+01	2.7613	2.4664
2.0E+01	2.9045	2.6085
3.0E+01	3.1065	2.8094
4.0E+01	3.2500	2.9524
5.0E+01	3.3614	3.0634
6.0E+01	3.4524	3.1542
8.0E+01	3.5961	3.2976
1.0E+02	3.7075	3.4089
1.5E+02	3.9101	3.6113
2.0E+02	4.0539	3.7549
3.0E+02	4.2566	3.9575
4.0E+02	4.4004	4.1012
5.0E+02	4.5119	4.2127
6.0E+02	4.6031	4.3039
8.0E+02	4.7469	4.4477
1.0E+03	4.8584	4.5592
1.5E+03	5.0612	4.7619
2.0E+03	5.2050	4.9057
3.0E+03	5.4077	5.1084
4.0E+03	5.5516	5.2523
5.0E+03	5.6631	5.3638
6.0E+03	5.7543	5.4550
8.0E+03	5.8981	5.5988

the long-time approximation applies within 1 percent when

$$t_D > 12.5\left(r_D^2 + \frac{1}{3}\right) \quad \ldots (24)$$

INFINITE-CONDUCTIVITY VERTICAL FRACTURE

The system of linear equations given by Eqs. 17 and 18 must be solved for $2q_m bx_f/q_f$, which represents the ratio of the flux per unit length in the mth segment, q_m, to the flux per unit length in the uniform flux fracture case, $q_f/2bx_f$. The stabilized value of $2q_m bx_f/q_f$ along the half-fracture length is shown in Fig. 5. Although uniform pressure in the fracture can be obtained with as little as 10 segments, it is necessary to use enough divisions to obtain a stabilized value of $\sigma_D(|x_D|<1, 0) = \sigma_{wD}$ in the fracture, as indicated by Fig. 6. The change in σ_{wD} is less than 5×10^{-5} when the number of fracture segments is increased from 59 to 60. In this study, we have used 90 segments to obtain a stabilized value of σ_{wD} in the fracture equal to −0.305. This value of σ_{wD} can be guaranteed to within 0.1 percent. The precision of determination of the dimensionless pressure given by Eq. 14 is, of course, much higher. Eq. 14 then yields for the long-time pressure drop on the fracture,

$$p_{wD}(t_D) = \frac{1}{2}\ln t_D + 1.100 \quad \ldots (25)$$

The same result can be obtained in the uniform flux fracture case by measuring the pressure drop at $x_D = 0.732$ in the fracture. This can be calculated by substituting −0.305 for $\sigma(x_D, 0)$ in Eq. 23. It is obvious in Fig. 7. This suggests that the *pressure drop on the fracture* for the infinite-conductivity fracture can be obtained from that for the *uniform flux fracture*, Eq. 20, with $x_D = 0.732$. The result is

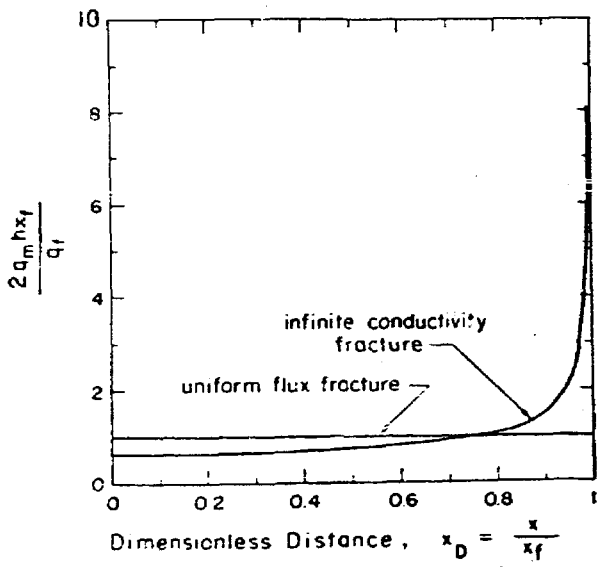

FIG. 5 — STABILIZED FLUX DISTRIBUTION ALONG VERTICAL FRACTURE.

$$p_{wD}(t_D) = \frac{1}{2}\sqrt{\pi t_D}\left[\operatorname{erf}\left(\frac{0.134}{\sqrt{t_D}}\right) + \operatorname{erf}\left(\frac{0.866}{\sqrt{t_D}}\right)\right] - 0.067\ \mathrm{Ei}\left(-\frac{0.018}{t_D}\right) - 0.433\ \mathrm{Ei}\left(-\frac{0.750}{t_D}\right) \quad \ldots\ldots\ldots (26)$$

Eq. 26 yields the correct value of the wellbore pressure for a well with an infinite-conductivity vertical fracture, at early and long times. It can be assumed that it also yields the correct pressure values during the transition period. A similar result ($x_D = 0.75$) has been obtained by Muskat[15] for a well with partial penetration at steady state. $p_{wD}(t_D)$ from Eq. 26 has been listed vs t_D in Table 1, and graphed in Figs. 8 and 9, where it corresponds to the ($x_e/x_f = \infty$) curve.

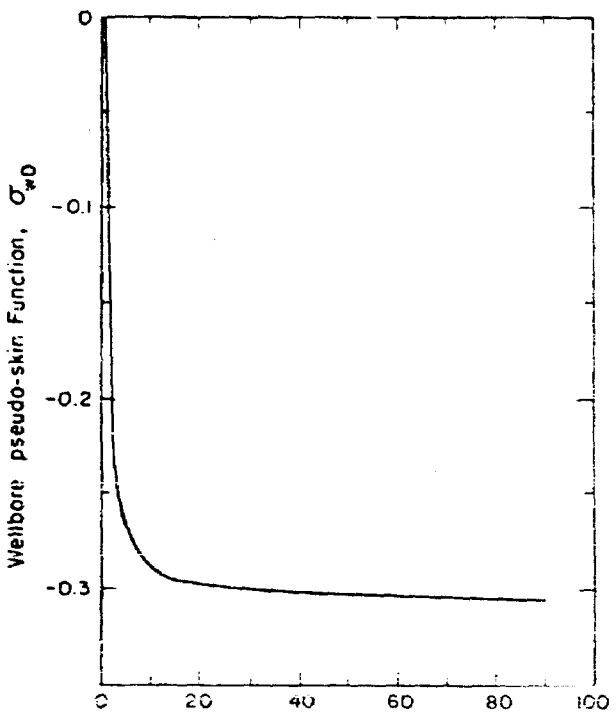

FIG. 6—CONVERGENCE OF THE WELLBORE PSEUDO SKIN FUNCTION σ_{wD} (INFINITE-CONDUCTIVITY FRACTURE).

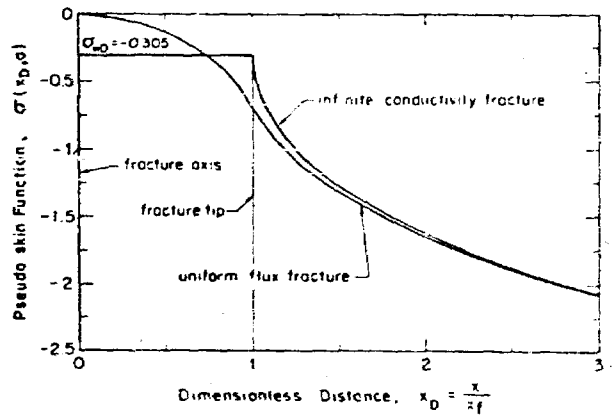

FIG. 7—PSEUDO SKIN FUNCTION VS DIMENSIONLESS DISTANCE.

VERTICALLY FRACTURED WELL IN A RECTANGULAR CLOSED RESERVOIR

When a reservoir is in an early stage of depletion, the production of a particular well is not perturbed by the existence of other wells or by boundary effects. After a while this is no longer true, and a new solution must be developed that considers the reservoir boundaries or the effect of the other wells.

Fig. 10 presents a schematic of a vertically fractured well in a rectangular, closed drainage system. Two types of fracture will be considered — uniform flux and infinite conductivity — but, as in the infinite-reservoir case, it is only necessary to derive the dimensionless pressure drop for the uniform flux fracture. This is obtained immediately

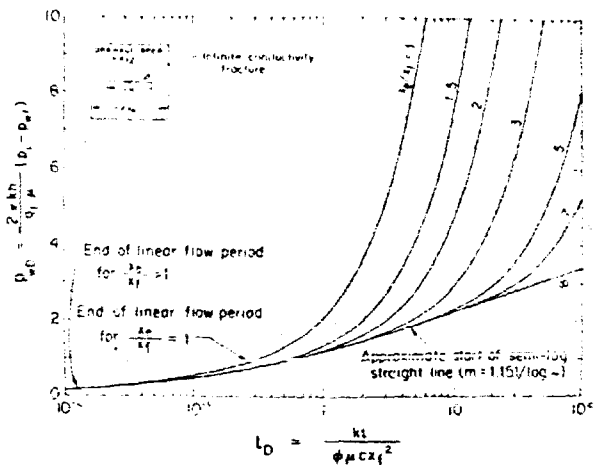

FIG. 8—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

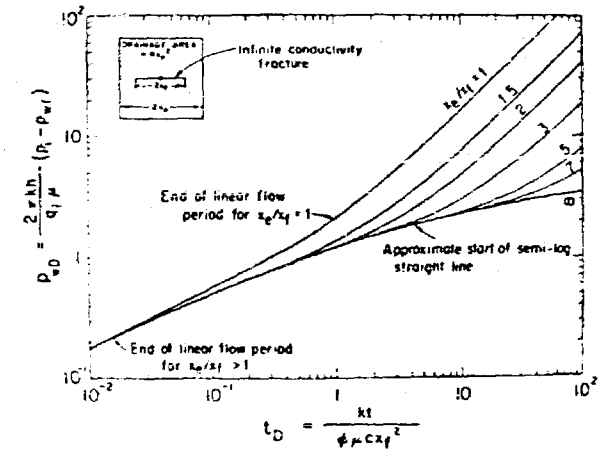

FIG. 9—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

by means of the Green's function and product solution method (see Ref. 14). The result is

$$p_D\left(\frac{x}{x_e},\frac{y}{y_e},t_{DA}\right) = 2\pi\int_0^{t_{DA}}\left[1+2\sum_{n=1}^{\infty}\cdot\exp\left(-n^2\pi^2\frac{x_e}{y_e}t'_{DA}\right)\cos n\pi\frac{y_w}{2y_e}\cdot\cos n\pi\frac{y_w+y}{2y_e}\right]\left[1+2\sum_{n=i}^{\infty}\exp\left(-n^2\pi^2\cdot\frac{y_e}{x_e}t'_{DA}\right)\frac{\sin n\pi\frac{x_f}{2x_e}}{n\pi\frac{x_f}{2x_e}}\cos n\pi\frac{x_w}{2x_e}\cdot\cos n\pi\frac{x_w+x}{2x_e}\right]dt'_{DA} \quad \ldots\ldots\ldots (27)$$

where t_{DA} represents the dimensionless time based on the drainage area:

$$t_{DA} = \frac{kt}{\phi\mu c 4(x_e\ y_e)^2} \quad \ldots\ldots\ldots (28)$$

The pressure drop on the fracture for a vertical fracture at the center of a square ($x_e = y_e$ and $x_w = y_w$) is then given by

$$p_{wD}(t_{DA}) = 2\pi\int_0^{t_{DA}}\left[1+2\sum_{n=1}^{\infty}\exp(-4n^2\pi^2t'_{DA})\right]\left[1+2\sum_{n=1}^{\infty}\exp(-4n^2\pi^2t'_{DA})\frac{\sin n\pi\frac{x_f}{x_e}}{n\pi\frac{x_f}{x_e}}\cdot\cos n\pi\ x_D\frac{x_f}{x_e}\right]dt'_{DA} \quad \ldots\ldots\ldots (29)$$

The pressure drops on the fracture for a uniform flux fracture and for an infinite-conductivity fracture are obtained by evaluating Eq. 29 at $x_D = 0$ and $x_D = 0.732$, respectively. The choice of the same point as in the infinite case leads to reasonable results and can be justified *a posteriori* by the method of *desuperposition*, presented later in this paper. Numerical values of the dimensionless pressure drop from Eq. 29 are listed vs t_{DA} in Tables 2 and 3, and have been plotted vs t_D (not t_{DA}) in Figs. 3 and 4 and Figs. 8 and 9, respectively, for various values of the x_e/x_f ratio. This ratio is used instead of Russell and Truitt's[8] fracture penetration ratio x_f/x_e because the limiting case of a vertical fracture in a square reservoir is a vertical fracture in an infinite reservoir (Figs. 3, 4, 8, and 9), which correspond to $x_e/x_f = \infty$, whereas a zero fracture penetration ratio ($x_f/x_e = 0$) corresponds to an unfractured well in a square reservoir, which is a different problem.

Three different flow periods can be characterized for both types of fractures: a *linear* flow period occurs at early times. This corresponds to the one-half slope straight line in log-log coordinates (Figs. 4 and 9). After a period of transition, there is a *pseudoradial* flow period corresponding to the semilog straight line (Figs. 3 and 8). After a second period of transition, *pseudosteady* state occurs, which is characterized by an approximate unit slope straight line in log-log coordinates. Depending upon x_e/x_f, one or more of these different flow periods may be missing; in the total fracture penetration case ($x_e/x_f = 1$), for instance, the first transition period and the pseudoradial period do not appear, whereas only the pseudoradial period is missing for values of x_e/x_f between 1 and 3 (uniform flux fracture), or 1 and 5 (infinite-conductivity fracture).

DISCUSSION OF VERTICAL FRACTURE SOLUTIONS

A comparison has been made in Table 4, and in Figs. 11 and 12 between the subject analytical solution for the *infinite-conductivity fracture* and Russell and Truitt's results.[8] As can be seen from Figs. 11 and 12, the smaller the x_e/x_f, the closer the two solutions become at long times. The over-all agreement is good, in view of the fact that the Russell and Truitt solution is an explicit finite-difference solution for a very difficult problem. The total fracture penetration cases ($x_e/x_f = 1$) agree exactly at all times. None of the Russell-Truitt curves, however, produce the 1.1515 slope semilog

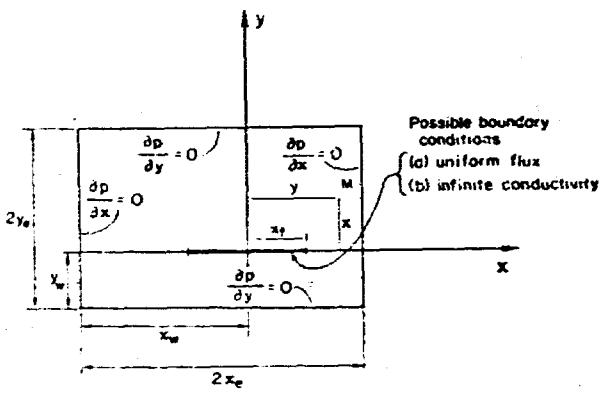

FIG. 10—VERTICAL FRACTURE IN A RECTANGULAR RESERVOIR.

straight line. This result was for many years erroneously thought by one of the authors of this study to be an inherent result of a vertical fracture, rather than an effect caused by the drainage boundaries. Furthermore, at very early times there are some discrepancies in the way the Russell-Truitt curves leave the log-log half-unit slope straight line, which makes them difficult to use with type-curve matching methods. Finally, the difference between the current analytical solution and the Russell-Truitt solution for $x_e/x_f = 10$ is much larger than that for other values of x_e/x_f. This Russell-Truitt case appears to contain an error and is not recommended for further use.

Russell and Truitt did not provide results for a vertically fractured well in an infinite reservoir, but such can be extracted from their results by *desuperposition*. The behavior of a fractured well in a square is identical with that of an infinite system containing a square array of fractured wells. The square array could be constructed by superposition of single fractured wells in infinite

TABLE 2 — p_{wD} FOR A UNIFORM FLUX VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1772	0.2481	0.3545	0.5306
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2171	0.3039	0.4340	0.6460
2.00E-04	0.0501	0.0752	0.1003	0.1504	0.2507	0.3509	0.5007	0.7392
3.00E-04	0.0614	0.0921	0.1228	0.1842	0.3070	0.4297	0.6105	0.8855
4.00E-04	0.0709	0.1063	0.1418	0.2127	0.3543	0.4957	0.6999	0.9986
5.00E-04	0.0793	0.1189	0.1585	0.2378	0.3962	0.5533	0.7756	1.0908
6.00E-04	0.0868	0.1302	0.1737	0.2605	0.4340	0.6046	0.8414	1.1686
8.00E-04	0.1003	0.1504	0.2005	0.3008	0.5007	0.6933	0.9515	1.2953
1.00E-03	0.1121	0.1681	0.2242	0.3363	0.5587	0.7686	1.0417	1.3963
1.50E-03	0.1373	0.2059	0.2746	0.4118	0.6790	0.9183	1.2145	1.5846
2.00E-03	0.1585	0.2378	0.3171	0.4752	0.7756	1.0334	1.3427	1.7211
3.00E-03	0.1942	0.2912	0.3883	0.5801	0.9261	1.2057	1.5294	1.9164
4.00E-03	0.2242	0.3363	0.4482	0.6661	1.0417	1.3336	1.6650	200565
5.00E-03	0.2507	0.3760	0.5007	0.7392	1.1355	1.4354	1.7716	2.1658
6.00E-03	0.2746	0.4118	0.5477	0.8030	1.2145	1.5199	1.8594	2.2554
8.00E-03	0.3171	0.4752	0.6297	0.9103	1.3427	1.6554	1.9990	2.3973
1.00E-02	0.3545	0.5306	0.6999	0.9986	1.4447	1.7619	2.1080	2.5078
1.50E-02	0.4342	0.6460	0.8414	1.1686	1.6344	1.9577	2.3073	2.7090
2.00E-02	0.5013	0.7393	0.9515	1.2953	1.7716	2.0981	2.4495	2.8520
3.00E-02	0.6140	0.8861	1.1183	1.4804	1.9676	2.2974	2.6505	3.0541
4.00E-02	0.7092	1.0011	1.2443	1.6159	2.1086	2.4400	2.7940	3.1980
5.00E-02	0.7935	1.0973	1.3470	1.7241	2.2201	2.5524	2.9069	3.3111
6.00E-02	0.8708	1.1819	1.4356	1.8161	2.3140	2.6469	3.0016	3.4061
8.00E-02	1.0127	1.3315	1.5893	1.9734	2.4732	2.8067	3.1618	3.5664
1.00E-01	1.1458	1.4678	1.7273	2.1129	2.6136	2.9473	3.3025	3.7072
1.50E-01	1.4652	1.7895	2.0502	2.4368	2.9381	3.2720	3.6273	4.0320
2.00E-01	1.7801	2.1047	2.3655	2.7523	3.2537	3.5876	3.9429	4.4477
3.00E-01	2.4086	2.7332	2.9941	3.3808	3.8823	4.2162	4.5715	4.9762
4.00E-01	3.0369	3.3615	3.6224	4.0092	4.5106	4.8445	5.1998	5.6045
5.00E-01	3.6652	3.9898	4.2507	4.6375	5.1389	5.4728	5.8281	6.2328
6.00E-01	4.2935	4.6181	4.8790	5.2658	5.7672	6.1011	6.4564	6.8512
8.00E-01	5.5501	5.8748	6.1357	6.5224	7.0239	7.3578	7.7131	8.1178
1.00E+00	6.8068	7.1314	7.3923	7.7791	8.2805	8.6144	8.9697	9.3744
1.50E+00	9 9484	10.2730	10.5339	10.9207	11.4221	11.7560	12.1113	12.5160
2.00E+00	13.0900	13.4146	13.6755	14.0623	14.5637	14.8976	15.2529	15.6576
3.00E+00	19.3732	19.6978	19.9587	20.3455	20.8469	21.1808	21.5361	21.9408
4.00E+00	25.6563	25.9810	26.2418	26.6286	27.1301	27.4639	27.8193	28.2240
5.00E+00	31.9395	32.3641	32.5250	32.9118	33.4132	33.7471	34.1024	34.5072
6.00E+00	38.2227	38.5473	38.8082	39.1950	39.6964	40.0303	40.3856	40.7904
8.00E+00	50.7891	51.1137	51.3746	51.7614	52.2628	52.5967	52.9520	53.3567

mediums in the same way a well in a closed square was constructed by Matthews *et al.*[18] and by Earlougher *et al.*[19] We realize that the pressure drop at a great distance from a fractured well produced at constant rate is essentially identical with the pressure drop caused by an unfractured well. Thus, the behavior of a fractured well in a closed square may be approximated by generating the drainage boundaries with unfractured wells, if x_e, x_f is large enough. This simple approach can also be used to extract the behavior of a fractured well in an infinite medium from that of a fractured well in a closed square. This can be stated as follows: the p_D for a fractured well in an infinite medium is equal to the p_D for a fractured well in a closed square, less the p_D for an unfractured well in a closed square, plus the p_D for an unfractured well in an infinite medium. The method has been applied to both the current analytical solutions and Russell-Truitt solutions for an infinite-conductivity fracture in a closed square reservoir (Table 4 and Fig. 13). The data for an unfractured well in a

TABLE 3 — p_{wD} FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1765	0.2433	0.3356	0.4735
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2145	0.2928	0.3996	0.5590
2.00E-04	0.0501	0.0752	0.1003	0.1502	0.2456	0.3327	0.4509	0.6278
3.00E-04	0.0614	0.0921	0.1228	0.1832	0.2955	0.3962	0.5328	0.7379
4.00E-04	0.0709	0.1063	0.1417	0.2104	0.3356	0.4471	0.5987	0.8259
5.00E-04	0.0793	0.1139	0.1582	0.2338	0.3697	0.4904	0.6549	0.9000
6.00E-04	0.0868	0.1302	0.1730	0.2545	0.3996	0.5284	0.7042	0.9642
8.00E-04	0.1003	0.1502	0.1989	0.2901	0.4509	0.5939	0.7889	1.0718
1.00E-03	0.1121	0.1676	0.2212	0.3204	0.4945	0.6496	0.8603	1.1600
1.50E-03	0.1373	0.2040	0.2671	0.3821	0.5833	0.7631	1.0027	1.3296
2.00E-03	0.1585	0.2338	0.3041	0.4315	0.6549	0.8536	1.1129	1.4560
3.00E-03	0.1942	0.2818	0.3633	0.5104	0.7691	0.9953	1.2792	1.6405
4.00E-03	0.2242	0.3204	0.4107	0.5738	0.8603	1.1050	1.4037	1.7750
5.00E-03	0.2507	0.3533	0.4509	0.6278	0.9367	1.1947	1.5033	1.8808
6.00E-03	0.2746	0.3821	0.4863	0.6753	1.0027	1.2707	1.5862	1.9681
8.00E-03	0.3171	0.4315	0.5470	0.7569	1.1129	1.3948	1.7196	2.1071
1.00E-02	0.3545	0.4735	0.5987	0.8259	1.2030	1.4941	1.8248	2.2158
1.50E-02	0.4342	0.5595	0.7043	0.9642	1.3754	1.6800	2.0189	2.4146
2.00E-02	0.5013	0.6295	0.7891	1.0718	1.5033	1.8152	2.1583	2.5564
3.00E-02	0.6140	0.7445	0.9239	1.2352	1.6896	2.0092	2.3567	2.7572
4.00E-02	0.7092	0.8406	1.0316	1.3592	1.8256	2.1492	2.4989	2.9006
5.00E-02	0.7935	0.9254	1.1235	1.4607	1.9342	2.2600	2.6110	3.0133
6.00E-02	0.8708	1.0030	1.2054	1.5486	2.0264	2.3536	2.7053	3.1081
8.00E-02	1.0127	1.1452	1.3521	1.7015	2.1838	2.5124	2.8649	3.2682
1.00E-01	1.1458	1.2784	1.4872	1.8392	2.3234	2.6527	3.0055	3.4089
1.50E-01	1.4652	1.5979	1.8081	2.1619	2.6474	2.9771	3.3301	3.7337
2.00E-01	1.7801	1.9128	2.1231	2.4772	2.9629	3.2926	3.6457	4.0493
3.00E-01	2.4086	2.5413	2.7516	3.1057	3.5915	3.9212	4.2743	4.6778
4.00E-01	3.0369	3.1696	3.3799	3.7341	4.2198	4.5495	4.9026	5.3061
5.00E-01	3.6652	3.7979	4.0082	4.3624	4.8481	5.1778	5.5309	5.9345
6.00E-01	4.2935	4.4262	4.6366	4.9907	5.4764	5.8061	6.1592	6.5628
8.00E-01	5.5501	5.6829	5.8932	6.2473	6.7331	7.0628	7.4159	7.8194
1.00E+00	6.8068	6.9395	7.1498	7.5040	7.9897	8.3194	8.6725	9.0761
1.50E+00	9.9484	10.0811	10.2914	10.6456	11.1313	11.4610	11.8141	12.2177
2.00E+00	13.0900	13.2227	13.4330	13.7872	14.2729	14.6026	14.9557	15.3592
3.00E+00	19.3732	19.5059	19.7162	20.0703	20.5561	20.8858	21.2389	21.6424
4.00E+00	25.6563	25.7891	25.9994	26.3535	26.8393	27.1690	27.5220	27.9256
5.00E+00	31.9395	32.0722	32.2826	32.6367	33.1224	33.4521	33.8052	34.2088
6.00E+00	38.2227	38.3554	38.5658	38.9199	39.4056	39.7353	40.0884	40.4920
8.00E+00	50.7891	50.9218	51.1321	51.4863	51.9720	52.3017	52.6548	53.0584

closed square were taken from Table 1, Ref. 19. It was found that desuperposition of the analytical solution for a closed square yields a very good approximation of the analytical solution for an infinite reservoir, for x_e/x_f values of 2, 5, and 10/3. This justifies *a posteriori* the choice of $s_{fD} = 0.732$ for representing the wellbore pressure for an infinite-conductivity fracture in the finite-reservoir case. x_e/x_f ratios of 10/7 and 1 gives p_D values that are much too large, implying that desuperposition cannot be used because the fracture is too close to the square boundary. The $x_e/x_f = 10$ case yields p_D values by desuperposition that are far too small. It is likely that the Russell and Truitt results have a small, almost constant error for this case. It should be noted, however, that the Russell and Truitt desuperposed solution for an infinite reservoir does have a slope of 1.151 when plotted on semilog coordinates, although their solutions for the closed square did not.

An interesting interpretation of the behavior of a vertically fractured well can be made in terms of an equivalent unfractured system. Prats[5] has shown that an infinite-conductivity vertical fracture, producing an incompressible fluid from a closed circular reservoir *at steady state*, is equivalent to an unfractured well with an effective radius equal to a quarter of the total fracture length, for ratios of the reservoir radius to the fracture half length greater than 2. The same is true, within 7 percent,

TABLE 4 — COMPARISON BETWEEN ANALYTICAL AND FINITE-DIFFERENCE WELLBORE PRESSURES FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A CLOSED SQUARE

t_{DA} / x_e/x_f=1	1		10/7		2	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.6 E-04	0.0354	0.0355	0.0506	0.0506	0.0709	0.0709
2.0 E-04	0.0501	0.0501	0.0716	0.0716	0.1003	0.1003
5.0 E-04	0.0793	0.0793	0.1132	0.1107	0.1582	0.1527
8.0 E-04	0.1003		0.1431		0.1989	
1.0 E-03	0.1121	0.1121	0.1598	0.1528	0.2212	0.2092
2.0 E-03	0.1585	0.1585	0.2233	0.2111	0.3041	0.2870
5.0 E-03	0.2507	0.2507	0.3386	0.3220	0.4509	0.4326
8.0 E-03	0.3171	0.3171	0.4142	0.3982	0.5470	0.5306
1.0 E-02	0.3545	0.3545	0.4548	0.4398	0.5987	0.5836
2.0 E-02	0.5013	0.5014	0.6062	0.5969	0.7891	0.7755
5.0 E-02	0.7935	0.7936	0.8973	0.8947	1.1235	1.1051
8.0 E-02	1.0127	1.0127	1.1160	1.1145	1.3521	1.3309
1.0 E-01	1.1458	1.1457	1.2489	1.2477	1.4872	1.4654
2.0 E-01	1.7801	1.7797	1.8832	1.8818	2.1231	2.1003
5.0 E-01	3.6652	3.6648	3.7683	3.7668	4.0082	3.9853
8.0 E-01	5.5501	5.5498	5.6532	5.6517	5.8932	5.8702
1.0 E+00	6.8068	6.8064	6.9099	6.9034	7.1498	7.1269
2.0 E+00	13.0900	13.0696	13.1930	13.1916	13.4330	13.4101
5.0 E+00	31.9395		32.0426		32.2826	
8.0 E+00	50.7891		50.8922		51.1321	

t_{DA} / x_e/x_f=1	10/3		5		10	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.0 E-04	0.1181	0.1182	0.1765	0.1772	0.3356	0.3545
2.0 E-04	0.1666	0.1671	0.2456	0.2476	0.4509	0.4715
5.0 E-04	0.2578	0.2463	0.3697	0.3575	0.6549	0.6395
8.0 E-04	0.3187		0.4509		0.7889	
1.0 E-03	0.3514	0.3318	0.4945	0.4780	0.8603	0.8013
2.0 E-03	0.4711	0.4480	0.6549	0.6390	1.1129	1.0171
5.0 E-03	0.6830	0.6586	0.9367	0.9164	1.5033	1.3697
8.0 E-03	0.8220	0.7951	1.1129	1.0872	1.7196	1.5732
1.0 E-02	0.8958	0.8668	1.2030	1.1742	1.8248	1.6735
2.0 E-02	1.1550	1.1167	1.5033	1.4659	2.1583	1.9970
5.0 E-02	1.5552	1.5045	1.9342	1.8894	2.6110	2.4430
8.0 E-02	1.7984	1.7442	2.1838	2.1372	2.8649	2.6958
1.0 E-01	1.9366	1.8817	2.3234	2.2766	3.0055	2.8361
2.0 E-01	2.5751	2.5189	2.9629	2.9154	3.6457	3.4757
5.0 E-01	4.4602	4.4039	4.8481	4.8004	5.5309	5.3607
8.0 E-01	6.3452	6.2889	6.7331	6.6853	7.4159	7.2456
1.0 E+00	7.6018	7.5455	7.9897	7.9419	8.6725	8.5023
2.0 E+00	13.8850	13.8287	14.2729	14.2252	14.9557	14.7855
5.0 E+00	32.7345		33.1224		33.8052	
8.0 E+00	51.5841		51.9720		52.6548	

for a compressible fluid at *steady* or *pseudosteady* state.[6] We can see that these results apply to a vertically fractured well in an infinite reservoir during the *pseudoradial* period, because Eq. 25 can be written as

$$p_{wD}(t_D) = \frac{1}{2}\left[\ln\left(\frac{kt}{\phi\mu c\left(\frac{x_f}{2}\right)^2}\right) + 0.80907\right] \quad \ldots\ldots\ldots \quad (30)$$

The effective well radius for an infinite-conductivity vertical fracture in an infinite reservoir is thus exactly one-fourth the total fracture length. The effective radius for an infinite-conductivity vertical fracture in a closed square reservoir at *pseudosteady state* may be obtained from the general pseudosteady-state depletion equation presented by Brons and Miller,[20] which, in the present case, can be expressed as

$$p_{wD} = 2\pi\, t_{DA} + \ln\frac{4(x_f/r'_w)}{\sqrt{e^{\gamma}C_A}}\,\frac{x_e}{x_f}, \quad \ldots \quad (31)$$

where C_A is the shape factor for a well in a square, and r'_w is the effective well radius. Effective radii computed from the current analytical solution and from the Russell and Truitt solution are compared in Fig. 14 with the results of Prats *et al.*[6] for various values of x_f/x_e (x_f/x_e is used for convenience in this case). Surprisingly, variations of the radii as a function of x_f/x_e are different in the Prats *et al.* results. Again, the result for x_f/x_e = 0.1 in Russell-Truitt's case is inconsistent with other results.

Comparison was also made between the subject solution and the analytical results of van Everdingen and Meyer[11] for an infinite-conductivity fracture in an infinite reservoir. Although not shown, results do not compare well. The van Everdingen and Meyer solution is correct during the initial linear flow period. But it yields a semilog straight line of slope 0.576 per $\log_{10}$ cycle, instead of 1.151 per $\log_{10}$ cycle as in the subject study, or as in the Russell and Truitt[8] desuperposed solution. It is not recommended that this solution be used in the pseudoradial flow period. Either the current analytical solution, or the desuperposed Russell-Truitt solution for a fractured well in an infinite medium may be used.

NOMENCLATURE

C_A = pseudosteady-state shape factor for a well at the center of a square[19] = 30.86

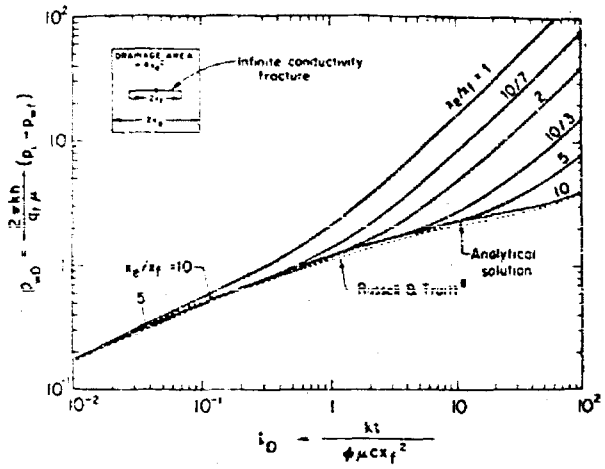

FIG. 12 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A CLOSED SQUARE.

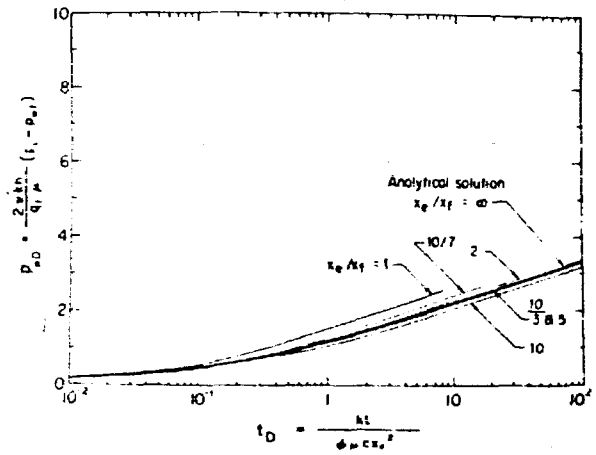

FIG. 13 — DESUPERPOSITION OF RUSSELL AND TRUITT RESULTS TO OBTAIN A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR AND COMPARISON WITH THE SUBJECT ANALYTICAL SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

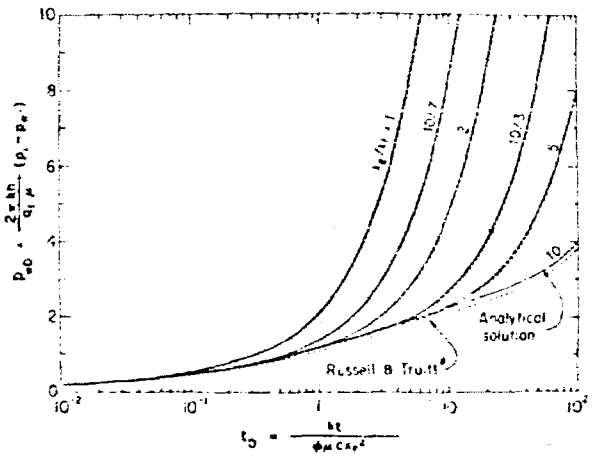

FIG. 11 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A SQUARE.

h = formation thickness
k = formation permeability
M = number of vertical fracture elements for generating an infinite-conductivity fracture
p = pressure
p_i = initial reservoir pressure
p_D = dimensionless pressure
q_f = total withdrawal rate from fracture
q_m = flux per unit area in vertical fracture elements
r = distance to fracture axis
r_D = dimensionless distance to fracture axis, based on fracture half length
r'_w = effective well radius
t = flowing time
t_D = dimensionless time based on the fracture half length
t'_D = dummy variable of integration
t_{DA} = dimensionless time based on drainage area
x,y = space coordinates
x_D,y_D = dimensionless coordinates based on the fracture half length
x_e, y_e = rectangular reservoir half dimensions
x_f = fracture half length
x_w, y_w = fracture axis coordinates
γ = Euler's constant = 0.5772
η = diffusivity constant
μ = fluid viscosity

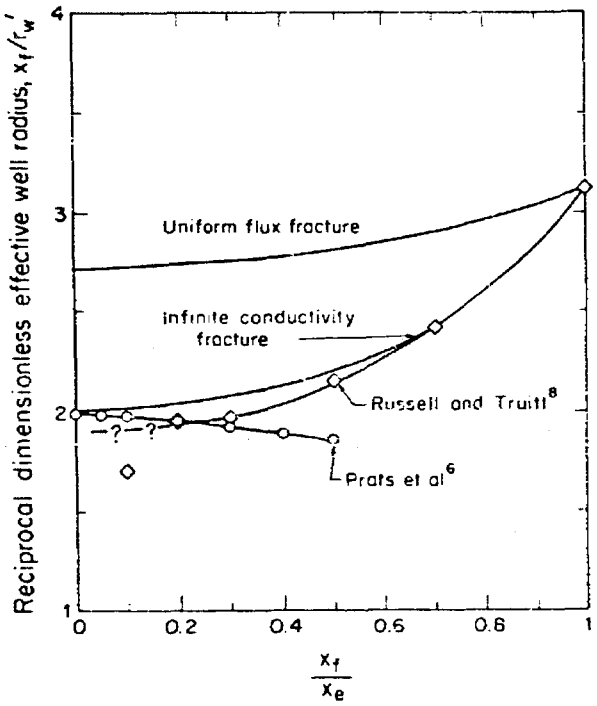

FIG. 14—COMPARISON OF RECIPROCAL DIMENSIONLESS EFFECTIVE WELL RADIUS, x_f/r'_w.

s = pseudo skin function, defined by Eq. 14
τ = dummy variable of integration
ϕ = formation porosity

SPECIAL FUNCTIONS

Inverse tangent function:

$$\arctan(x) = \tan^{-1}(x)$$

Exponential integral:

$$-Ei(-x) = \int_0^x \frac{e^{-u}}{u}\,du$$

Error function:

$$erf(x) = \frac{2}{\sqrt{\pi}} \int_0^x e^{-u^2}\,du$$

Complementary error function:

$$erfc(x) = 1 - erf(x)$$

Units: CGS units are used throughout this study.

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OIL CONSERVATION DIVISION
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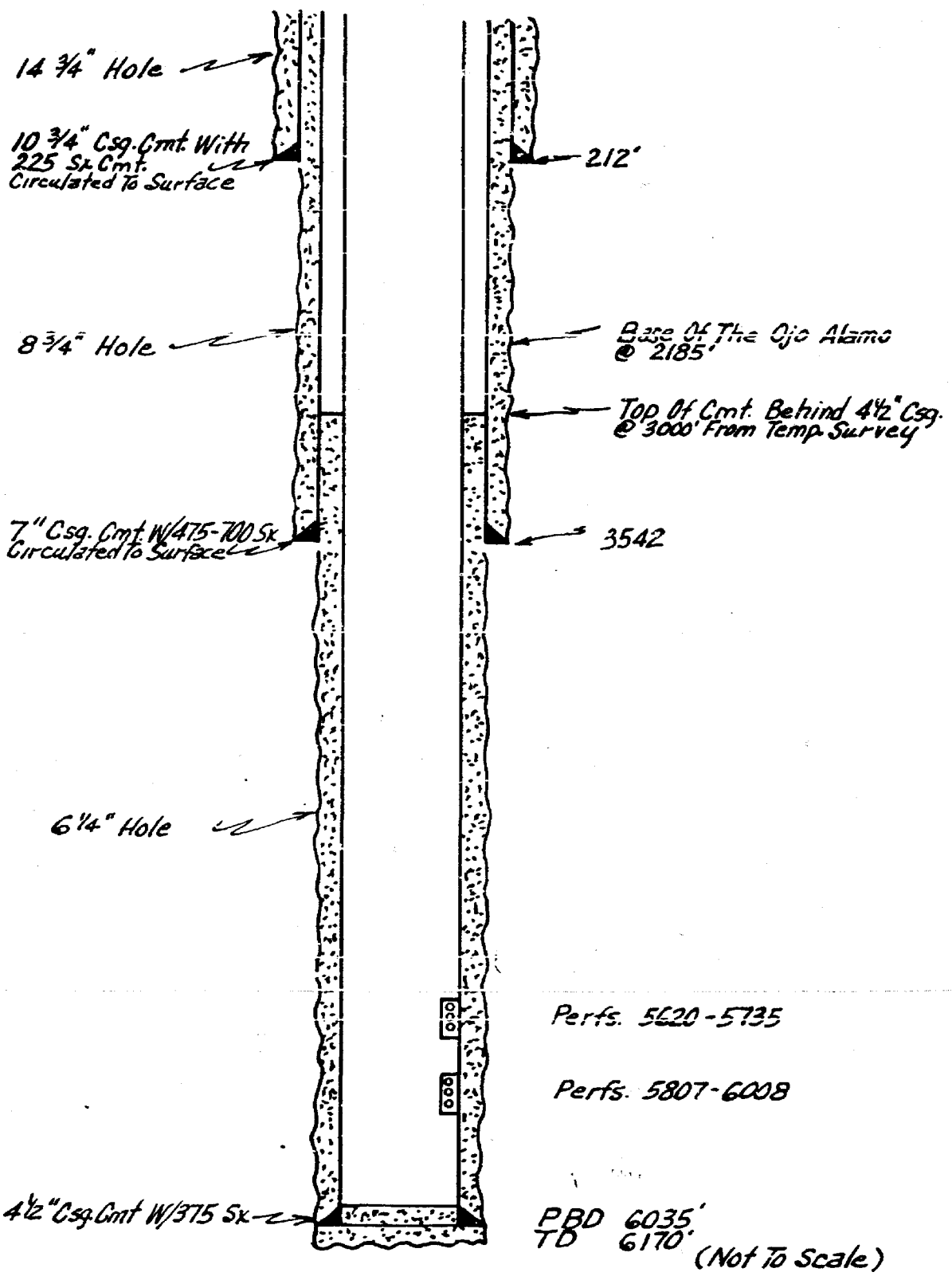

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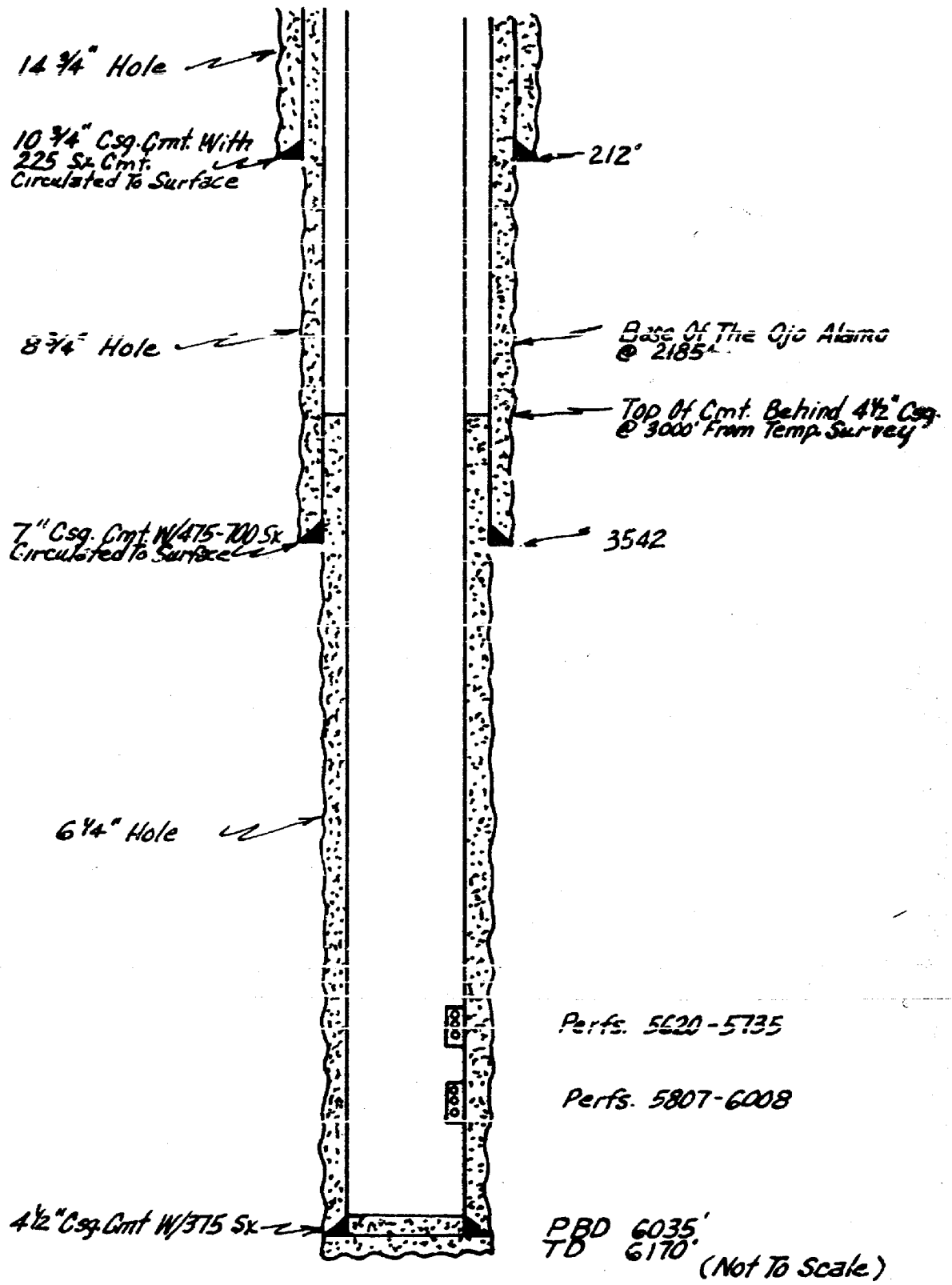

Unsteady-State Pressure Distributions Created by a Well With a Single Infinite-Conductivity Vertical Fracture

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INTRODUCTION

During the last few years, there has been an explosion of information in the field of well-test analysis. Because of increased physical understanding of transient fluid flow, it is possible to analyze the entire pressure history of a well test, not just long-time data as in conventional analysis.[1] It is now often possible to specify the time of beginning of the correct semilog straight line and determine whether the correct straight line has been properly identified. It is also possible to identify wellbore storage effects, and the nature of wellbore stimulation as to permeability improvement, or fracturing, and to quantitatively analyze those effects.

Such accomplishments have been augmented by attempts to understand the short-time pressure data from well testing — data that were often classified as too complex for analysis. One recent study of short-time pressure behavior[2] showed that it was important to specify the physical nature of the stimulation in considering the behavior of a stimulated well. That is, stating that the van Everdingen-Hurst infinitesimal skin effect was negative was not sufficient to define short-time well behavior. For instance, acidized (but not acid-fractured) and hydraulically fractured wells might not necessarily exhibit the same behavior at early times, even though they could possess the same value of negative skin effect.

In the same manner, hydraulic fracturing leading to horizontal or vertical fractures could produce the same skin effect, but with possibly different short-time pressure data. This could then provide a way to determine the orientation of fractures created by this type of well stimulation. In fact, it is generally agreed that hydraulic fracturing usually results in one vertical fracture, the plane of which includes the wellbore. Most studies of the flow behavior for a fractured well consider vertical fractures only.[3-11]

Yet it is also agreed that horizontal fractures *could* occur in shallow formations. Furthermore, it would appear that notch-fracturing would lead to horizontal fractures. Surprisingly, no detailed study of the horizontal fracture case had been performed until recently.[12] A solution to this problem was presented by Gringarten and Ramey.[13] In the course of their study, it was found that a large variety of new transient pressure behavior solutions useful in well and reservoir analysis could be constructed from instantaneous Green's functions.[14] Possibilities included a well with a single vertical fracture in an infinite reservoir, or at any location in a rectangle.

Although similar cases had been studied before by van Everdingen and Meyer,[11] and by Russell and Truitt,[8] there were confusing differences in their respective results, and small inconsistencies between the cases of Ref. 8 made short-time analysis impossible. Both explicit and implicit finite-difference solutions and finite-element solutions were made for the vertical fracture case of Russell and Truitt in an attempt to eliminate differences between Refs. 8 and 11, and internal differences between cases in Ref. 8. It was not possible to reach satisfactory conclusions for the short-time performance region with even very long computer runs with *either* finite-difference or finite-element[12] programs. For this reason, it was decided to evaluate analytical solutions to provide a sound basis for short-time analysis of field data. In the course of the work, to provide a direct comparison with the Russell and Truitt data it became necessary to develop analytical solutions for fracture cases in which the fluid entry flux along the fracture caused a constant pressure along the fracture (infinite fracture conductivity). It also appeared worthwhile to evaluate the new solutions so that vertical fracture behavior could be compared with horizontal fracture behavior in infinite reservoirs. The new solutions for vertically fractured wells are especially useful for short-time or type-curve analysis. Such an analysis can provide information concerning permeabilities, fracture

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**Now with Amoco Production Co., Tulsa, Okla.
[1]References listed at end of paper.

This page of *Petroleum Transactions, AIME* follows page 308. The intervening non-Transactions pages appeared in *Society of Petroleum Engineers Journal*.

length, and distance to a symmetrical drainage limit. Combination of short-time analysis with older conventional semilog analytical methods permits an extraordinary confidence level concerning the analysis of field data.

VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

We model a plane (zero-thickness) vertical fracture totally penetrating a horizontal, homogeneous, and isotropic reservoir initially at constant pressure. At time zero, a single-phase, slightly compressible fluid flows from the reservoir into the fracture at a constant total rate. The producing pressure is uniform over the fracture (infinite fracture conductivity). The pressure remains constant and equal to the initial pressure as distance from the well becomes infinitely large (infinite reservoir).

An analytical expression for the pressure distribution created by the plane vertical fracture may be obtained by the Green's function and product solution method,[22] using source functions presented by Gringarten and Ramey.[14] The condition of uniform pressure over the fracture at all times is satisfied, as indicated in Ref. 14, by dividing the half-fracture length x_f into M segments of length x_f/M, each with a uniform flux per unit area, q_m, $(m = 1,M)$. The first segment extends from 0 to x_f/M, the second segment from x_f/M to $2x_f/M$, the mth segment from $[(m-1)x_f]/M$ to mx_f/M, and the last segment from $[(M-1)/M]x_f$ to x_f, as shown in Fig. 1. The q_m $(m = 1,M)$ are determined by equating the pressure drops at the center of the segments, which provide $(M-1)$ equations, the mth equation being obtained from the condition of constant total production rate at all times:

$$\begin{cases} \Delta p\left(\frac{2j-1}{2M}\, x_f, 0, t\right) = \Delta P\left(\frac{2j+1}{2M}\, x_f, 0, t\right) \quad j=1,M-1 \quad \ldots(1) \\ 2\sum_{m=1}^{M} q_m\left(\frac{x_f}{M}\right)h = q_f \quad \ldots\ldots(2) \end{cases}$$

The pressure drop created by the fracture is obtained from Ref. 14, Table 5:

$$p_i - p_{x,y,t} = \frac{1}{\phi c}\int_0^t \left\{\sum_{m=1}^{M} q_m(\tau) \int_{\frac{(m-1)x_f}{M}}^{\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2+y^2}{4\eta(t-\tau)}\right]dx_w - \sum_{m=1}^{M} q_m(\tau) \left\{\int_{-\frac{(m-1)}{M}x_f}^{-\frac{mx_f}{M}} \exp\left[-\frac{(x-x_w)^2+y^2}{4\eta(t-\tau)}\right]dx_w\right\} \cdot \frac{d\tau}{4\pi\eta(t-\tau)} \quad \ldots\ldots(3)$$

The coordinate system in Fig. 1 and Eq. 3 is different from that of Ref. 14, however. A similar scheme has been used by Muskat[15] for the steady-state pressure distribution created by a partially penetrating well, and has been suggested by Burns[16] for unsteady state. In the unsteady state, however, the method seems impractical: it was expected — and confirmed from a numerical simulation[21] — that the flux per unit area of fracture is not constant but varies in time. A system of M equations and M unknowns as represented by Eqs. 1 and 2 should thus be solved at each value of time.

Actually, this is not true practically, and the pressure distribution can be obtained by solving the system of equations only once. The flux distribution in the fracture at various times, as obtained from a numerical simulation, is shown in Fig. 2. It can be seen that the flux distribution is uniform at very early times, then it changes, and finally it reaches a steady state at some extended time, after which flow entering the fracture stabilizes. The pressure during the stabilized flow period is independent of the flux distribution history, and is the same as if the flux distribution had been equal to the final stabilized flux distribution at all times.

An analog to this interesting and useful fact

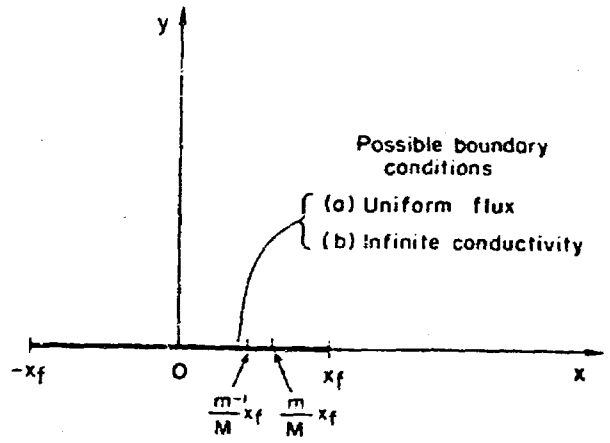

FIG. 1 — VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

occurs in the case of flow to a constant-rate well with wellbore storage. Wellbore storage causes the sand-face production rate to change as a function of time initially. But after some initial period, the sand-face rate reaches the constant surface rate (within a specified percentage), and thereafter the producing pressure is equal to that of a well whose sand-face rate had been constant from the start of production. The pressure is independent of the production history! The same sort of observation was made in another reservoir problem by Carter and Tracy.[23]

By solving the system of Eqs. 1 and 2 for the *stabilized flux distribution* one can obtain a long-time solution for the pressure, whereas an early-time solution can be obtained by assuming uniform flux. We shall show that these also provide an excellent approximation for the pressure distribution at all times.

EARLY-TIME SOLUTION

Integrating Eq. 3 with respect to x_w, the dimensionless pressure drop can be written as

$$p_D(x_D,y_D,t_D) = \int_0^{t_D} \exp\frac{y_D^2}{4(t-t')_D} \sum_{m=1}^{M} \left(\frac{2q_m(t'_D)hx_f}{q_f}\right) \left[\operatorname{erf}\frac{x_D+\frac{m}{M}}{\sqrt{(t-t')_D}} - \operatorname{erf}\frac{x_D+\frac{m-1}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf}\frac{x_D-\frac{m}{M}}{2\sqrt{(t-t')_D}} + \operatorname{erf}\frac{x_D-\frac{m-1}{M}}{2\sqrt{(t-t')_D}}\right] \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

The dimensionless space and time variables in Eq. 4 are based on the fracture half-length x_f,

$$x_D = \frac{x}{x_f} \; ; \quad y_D = \frac{y}{x_f} , \quad \ldots\ldots\ldots (5)$$

and the dimensionless time and the dimensionless pressure drop are, respectively,

$$t_D = \frac{kt}{\phi\mu c x_f^2} , \quad \ldots\ldots\ldots\ldots (6)$$

and

$$p_D(x_D,y_D,t_D) = \frac{2\pi kh}{q_f\mu}(p_i - p_{x,y,t}) . \quad \ldots\ldots\ldots\ldots\ldots\ldots (7)$$

At very early times, the expression

$$\operatorname{erf}\frac{x_D \pm \frac{m}{M}}{2\sqrt{(t-t')_D}} - \operatorname{erf}\frac{x_D \pm \frac{m-1}{M}}{2\sqrt{(t-t')_D}}$$

becomes constant when t_D is small enough.[14] (The constant is 2 if $(m-1)/M < |x_D| < m/M$; unity if $|x_D| = (m-1)/M$ or $|x_D| = m/M$; and zero if $|x_D| < (m-1)/M$ or $|x_D| > m/M$.) Therefore, at very early times the system given by Eqs. 1 and 2 reduces to

$$\begin{cases} \displaystyle\int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \frac{2q_j(t'_D)hx_f}{q_f} \cdot \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}} = \int_0^{t_D} \exp\left[-\frac{y_D^2}{4(t-t')_D}\right] \cdot \frac{2q_{j+1}(t'_D)hx_f}{q_f} \frac{dt'_D}{4[(t-t')_D/\pi]^{1/2}}, \\ \qquad j=1,\ M-1 \quad \ldots\ldots\ldots (8) \\ \displaystyle\sum_{m=1}^{M} \frac{2q_m(t_D)hx_f}{q_f} = M, \quad \text{all } t_D . \quad \ldots\ldots\ldots (9) \end{cases}$$

which yields

$$q_j = \frac{q_f}{2hx_f} , \quad j=1,M$$

As indicated by the numerical model, the flux must be uniform over the fracture at very early times, and the early-time solution for the pressure drop function is

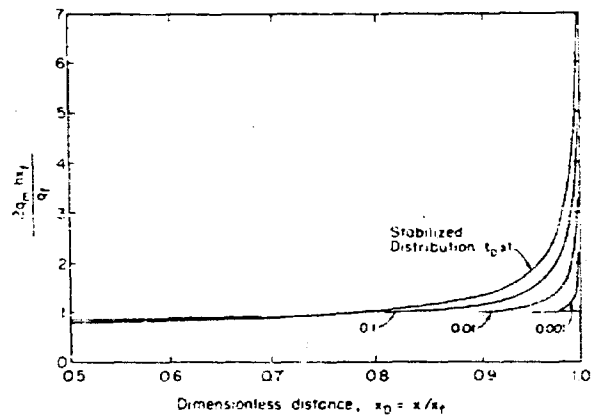

FIG. 2 — FLUX DISTRIBUTION AT VARIOUS TIMES ALONG AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE (NUMERICAL MODEL).

$$p_D(|x_D|<1, y_D, t_D) =$$

$$\int_0^{t_D} \exp\left(-\frac{y_D^2}{4t'_D}\right) \frac{dt'_D}{2(t'_D/\pi)^{1/2}}$$

$$= (\pi t_D)^{\frac{1}{2}} \exp(-y_D^2/4t_D)$$

$$- |y_D| \operatorname{erfc}(|y_D|/2\sqrt{t_D}) \quad \ldots (10)$$

$$p_D(|x_D|>1, y_D, t_D) = 0$$

and, along the fracture,

$$p_{wD}(|x_D|<1, 0, t_D) = \sqrt{\pi t_D}, \quad \ldots (11)$$

which is the conventional result for flow in a linear system. In this case, there is flow into both sides of the fracture.

LONG-TIME SOLUTION

During the stabilized flow period, the q_m's are constant and can be taken out of the integral sign in Eq. 3. Inverting the order of integration in Eq. 3, one obtains

$$p_D(x_D, y_D, t_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} \left\{ \int_{\frac{m-1}{M}}^{\frac{m}{M}} -Ei\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] dx_{wD} \right.$$

$$\left. - \int_{\frac{m-1}{M}}^{\frac{m}{M}} - Ei\left[-\frac{(x-x_w)_D^2 + y_D^2}{4t_D}\right] \cdot dx_{wD} \right\}, \quad \ldots (12)$$

with

$$\sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} = M \quad \ldots (13)$$

Substituting the series expansion of the exponential integral function into Eq. 12 yields the long-time solution for the dimensionless pressure drop function:

$$p_D(x_D, y_D, t_D) = \frac{1}{2}(\ln t_D + 2.80907) + \sigma(x_D, y_D), \quad \ldots (14)^*$$

where $\sigma(x_D, y_D)$ is a *pseudo skin function* that depends upon the position of the pressure point only:

$$\sigma(x_D, y_D) = \frac{1}{4} \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} \cdot \left\{ (x_D - \tfrac{m}{M}) \ln[y_D^2 + (x_D - \tfrac{m}{M})^2] \right.$$

$$- (x_D + \tfrac{m}{M}) \ln[y_D^2 + (x_D + \tfrac{m}{M})^2]$$

$$+ (x_D + \tfrac{m-1}{M}) \ln[y_D^2 + (x_D + \tfrac{m-1}{M})^2]$$

$$- (x_D - \tfrac{m-1}{M}) \ln[y_D^2 + (x_D - \tfrac{m-1}{M})^2]$$

$$- 2y_D \arctan\left[\frac{2y_D}{M}\left(r_D^2 + \frac{m(m-1)}{M^2}\right) \div \left([r_D^2 - (\tfrac{m}{M})^2][r_D^2 - (\tfrac{m-1}{M})^2] + \frac{4m(m-1)}{M^2} y_D^2\right)\right] \left. \right\} \quad \ldots (15)$$

where $r_D = r/x_f$ is the dimensionless distance to the axis of the fracture.

Eq. 14 has a form similar to the long-time approximation of the pressure function for radial flow[17] (i.e., a circular well without a fracture):

$$\frac{2\pi kh}{q\mu}(p_i - p_{r,t}) = \frac{1}{2}\left(\ln \frac{kt}{\phi \mu c r^2} + 0.80907\right), \quad r \geq r_w \quad \ldots (16)$$

As in the radial flow case, a straight line of slope 1.1515 per logarithmic cycle is obtained when the long-time dimensionless pressure drop is plotted vs the dimensionless flowing time on semilog coordinates. Thus, well test analysis methods developed for transient *radial* flow problems and based upon the existence of the 1.1515 slope semilog straight line, can be extended to analyze transient flow into a vertically fractured well in an infinite system. Actually, it can be shown that Eq. 14 becomes identical with Eq. 16 if x_f

*"2.80907" is correct.

tends to zero, or if t becomes very large.

The q_m's $(m=1,M)$ in Eq. 15 are obtained by solving the system of equations represented by Eqs. 1 and 2, which now reduces to

$$\begin{cases} \sigma\left(\frac{2j-1}{2M},\ 0\right) = \sigma\left(\frac{2j+1}{2M},\ 0\right) \\ \qquad j = 1, M-1 \quad \ldots\ldots (17) \\ \sum_{m=1}^{M} \frac{2q_m h x_f}{q_f} = M \quad \ldots (18) \end{cases}$$

UNIFORM FLUX VERTICAL FRACTURE

This case corresponds to $M = 1$ and represents a first approximation of the behavior of a vertically fractured well. At early times, however, it is the exact solution.

The corresponding form of Eq. 4 is

$$p_D(x_D,y_D,t_D) = \int_0^{t_D} \exp\left(-\frac{y_D^2}{4t'_D}\right) \cdot \left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t'_D}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t'_D}}\right] \frac{dt'_D}{4(t'_D/\pi)^{1/2}} \quad \ldots\ldots (19)$$

Eq. 19 cannot be expressed in terms of tabulated functions, and must be evaluated with a computer, except in the plane of the fracture ($y_D = 0$), where it becomes

$$p_D(x_D,0,t_D) = \frac{1}{2}(\pi t_D)^{1/2}\left[\operatorname{erf}\frac{1-x_D}{2\sqrt{t_D}} + \operatorname{erf}\frac{1+x_D}{2\sqrt{t_D}}\right] - \frac{(1-x_D)}{4}\operatorname{Ei}\left[-\frac{(1-x_D)^2}{4t_D}\right] - \frac{(1+x_D)}{4}\operatorname{Ei}\left[-\frac{(1+x_D)^2}{4t_D}\right] \quad \ldots\ldots (20)$$

Eq. 20 shows that pressure will vary along the fracture length (except at early times), which would not be true if the fracture had infinite conductivity. However, the pressure drop along the fracture is low, and the uniform flux condition gives the appearance of a high, but not infinite, fracture conductivity. Some field data appear to match this solution better than the infinite-conductivity solution.

One useful expression for well test analysis is the pressure drop on the axis of the fracture ($x_D = 0$, $t_D > 0$):

$$p_{wD}(t_D) = \sqrt{\pi t_D}\ \operatorname{erf}\left(\frac{1}{2\sqrt{t_D}}\right) - \frac{1}{2}\operatorname{Ei}\left(-\frac{1}{4t_D}\right) \quad \ldots\ldots (21)$$

$p_{wD}(t_D)$ has been listed vs t_D in Table 1, and plotted in Figs. 3 and 4 as the $(x_e/x_f = \infty)$ curve.

Approximating forms of Eq. 19 at small and large values of time are the same as obtained in the previous section. The sigma pseudo skin function for the long-time approximation, Eq. 15, simplifies to

$$\sigma(x_D,y_D) = \frac{1}{4}\left\{(x_D-1)\ln[y_D^2+(x_D-1)^2] - (x_D+1)\ln[y_D^2+(x_D+1)^2] - 2y_D \arctan\frac{2y_D}{r_D^2-1}\right\} \quad \ldots (22)$$

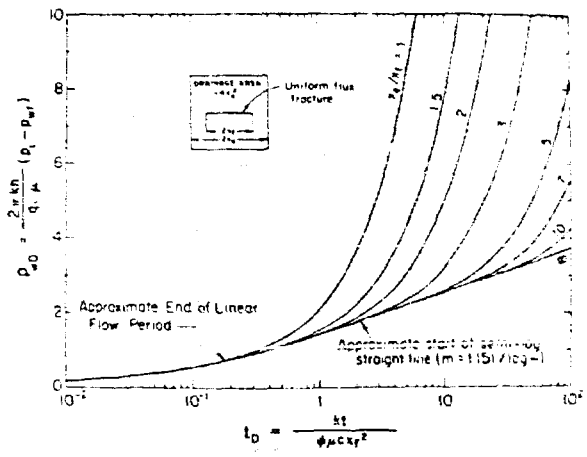

FIG. 3—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

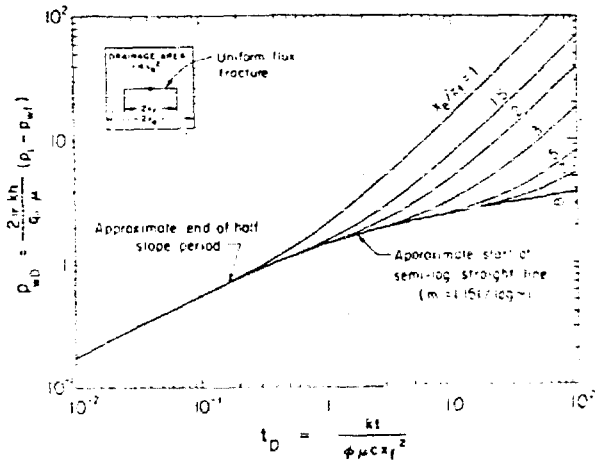

FIG. 4—p_{wD} VS t_D FOR A UNIFORM FLUX VERTICAL FRACTURE.

and in the plane of the fracture,

$$\sigma_D(x_D,0) = -\frac{1}{2}\left[(1-x_D)\ \ln|1-x_D| + (1+x_D)\ \ln|1+x_D|\right] \quad \ldots (23)$$

TABLE 1 — p_{wD} FOR A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR

t_D	Uniform flux	Infinite Conductivity
1.0E-02	0.1772	0.1765
1.5E-02	0.2171	0.2145
2.0E-02	0.2507	0.2456
3.0E-02	0.3070	0.2955
4.0E-02	0.3545	0.3356
5.0E-02	0.3963	0.3697
6.0E-02	0.4340	0.3996
8.0E-02	0.5007	0.4509
1.0E-01	0.5587	0.4945
1.5E-01	0.6790	0.5833
2.0E-01	0.7756	0.6549
3.0E-01	0.9261	0.7691
4.0E-01	1.0417	0.8603
5.0E-01	1.1355	0.9367
6.0E-01	1.2145	1.0027
8.0E-01	1.3427	1.1129
1.0E+00	1.4447	1.2030
1.5E+00	1.6344	1.3754
2.0E+00	1.7716	1.5032
3.0E+00	1.9676	1.6894
4.0E+00	2.1080	1.8248
5.0E+00	2.2175	1.9312
6.0E+00	2.3073	2.0189
8.0E+00	2.4494	2.1583
1.0E+01	2.5600	2.2673
1.5E+01	2.7613	2.4664
2.0E+01	2.9045	2.6085
3.0E+01	3.1065	2.8094
4.0E+01	3.2500	2.9524
5.0E+01	3.3614	3.0634
6.0E+01	3.4524	3.1542
8.0E+01	3.5961	3.2976
1.0E+02	3.7075	3.4089
1.5E+02	3.9101	3.6113
2.0E+02	4.0539	3.7549
3.0E+02	4.2566	3.9575
4.0E+02	4.4004	4.1012
5.0E+02	4.5119	4.2127
6.0E+02	4.6031	4.3039
8.0E+02	4.7469	4.4477
1.0E+03	4.8584	4.5592
1.5E+03	5.0612	4.7619
2.0E+03	5.2050	4.9057
3.0E+03	5.4077	5.1084
4.0E+03	5.5516	5.2523
5.0E+03	5.6631	5.3638
6.0E+03	5.7543	5.4550
8.0E+03	5.8981	5.5988

the long-time approximation applies within 1 percent when

$$t_D > 12.5\ (r_D^2 + \frac{1}{3}) \quad \ldots (24)$$

INFINITE-CONDUCTIVITY VERTICAL FRACTURE

The system of linear equations given by Eqs. 17 and 18 must be solved for $2q_m hx_f/q_f$, which represents the ratio of the flux per unit length in the mth segment, q_m, to the flux per unit length in the uniform flux fracture case, $q_f/2hx_f$. The stabilized value of $2q_m hx_f/q_f$ along the half-fracture length is shown in Fig. 5. Although uniform pressure in the fracture can be obtained with as little as 10 segments, it is necessary to use enough divisions to obtain a stabilized value of $\sigma_D(|x_D|<1,\ 0) = \sigma_{wD}$ in the fracture, as indicated by Fig. 6. The change in σ_{wD} is less than 5×10^{-5} when the number of fracture segments is increased from 59 to 60. In this study, we have used 90 segments to obtain a stabilized value of σ_{wD} in the fracture equal to −0.305. This value of σ_{wD} can be guaranteed to within 0.1 percent. The precision of determination of the dimensionless pressure given by Eq. 14 is, of course, much higher. Eq. 14 then yields for the long-time pressure drop on the fracture,

$$p_{wD}(t_D) = \frac{1}{2}\ln t_D + 1.100 \quad \ldots (25)$$

The same result can be obtained in the uniform flux fracture case by measuring the pressure drop at $x_D = 0.732$ in the fracture. This can be calculated by substituting −0.305 for $\sigma(x_D, 0)$ in Eq. 23. It is obvious in Fig. 7. This suggests that the *pressure drop on the fracture* for the infinite-conductivity fracture can be obtained from that for the *uniform flux fracture*, Eq. 20, with $x_D = 0.732$. The result is

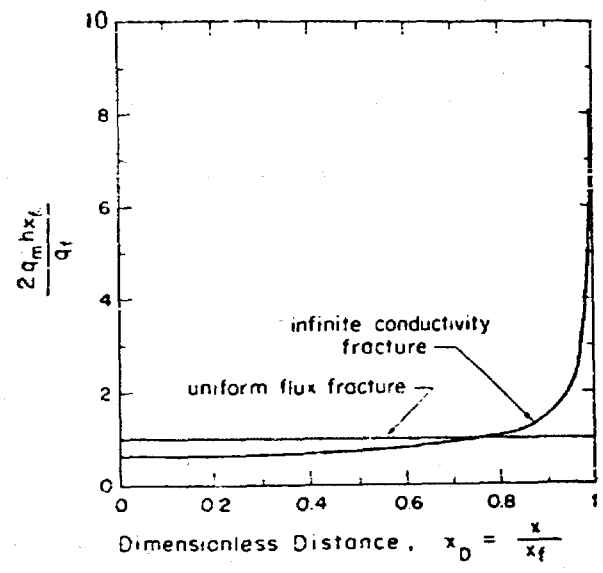

FIG. 5 — STABILIZED FLUX DISTRIBUTION ALONG VERTICAL FRACTURE.

$$p_{wD}(t_D) = \frac{1}{2}\sqrt{\pi t_D}\left[\operatorname{erf}\left(\frac{0.125}{\sqrt{t_D}}\right) + \operatorname{erf}\left(\frac{0.866}{\sqrt{t_D}}\right)\right] - 0.067\ \mathrm{Ei}\left(-\frac{0.018}{t_D}\right) - 0.433\ \mathrm{Ei}\left(-\frac{0.750}{t_D}\right) \quad \ldots\ldots\ldots (26)$$

Eq. 26 yields the correct value of the wellbore pressure for a well with an infinite-conductivity vertical fracture, at early and long times. It can be assumed that it also yields the correct pressure values during the transition period. A similar result ($x_D = 0.75$) has been obtained by Muskat[15] for a well with partial penetration at steady state. $p_{wD}(t_D)$ from Eq. 26 has been listed vs t_D in Table 1, and graphed in Figs. 8 and 9, where it corresponds to the ($x_e/x_f = \infty$) curve.

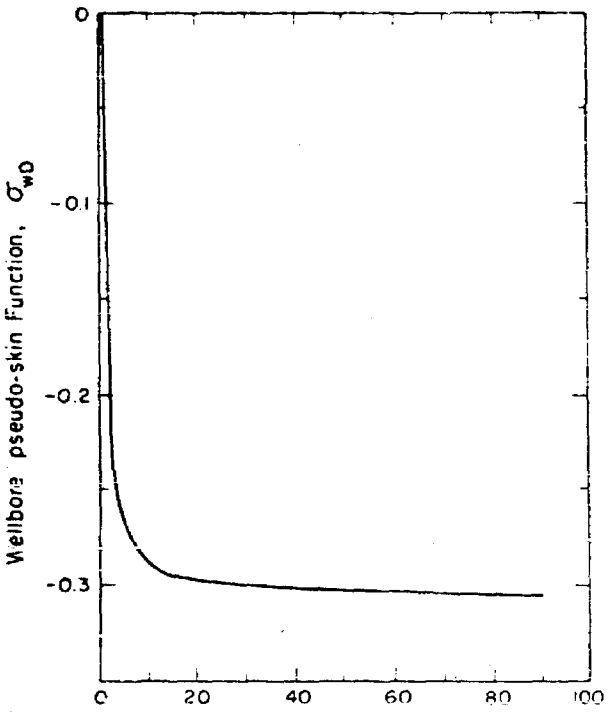

FIG. 6—CONVERGENCE OF THE WELLBORE PSEUDO SKIN FUNCTION σ_{wD} (INFINITE-CONDUCTIVITY FRACTURE).

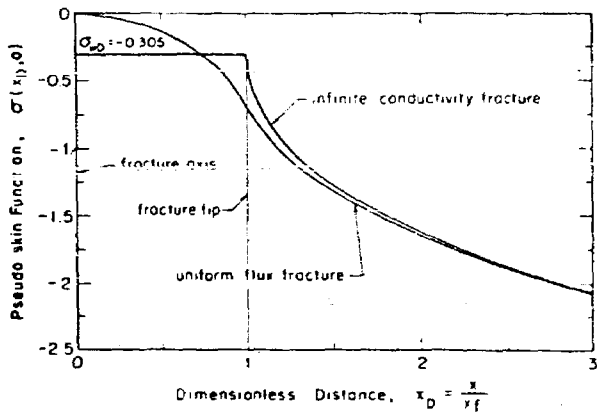

FIG. 7—PSEUDO SKIN FUNCTION VS DIMENSIONLESS DISTANCE.

VERTICALLY FRACTURED WELL IN A RECTANGULAR CLOSED RESERVOIR

When a reservoir is in an early stage of depletion, the production of a particular well is not perturbed by the existence of other wells or by boundary effects. After a while this is no longer true, and a new solution must be developed that considers the reservoir boundaries or the effect of the other wells.

Fig. 10 presents a schematic of a vertically fractured well in a rectangular, closed drainage system. Two types of fracture will be considered — uniform flux and infinite conductivity — but, as in the infinite-reservoir case, it is only necessary to derive the dimensionless pressure drop for the uniform flux fracture. This is obtained immediately

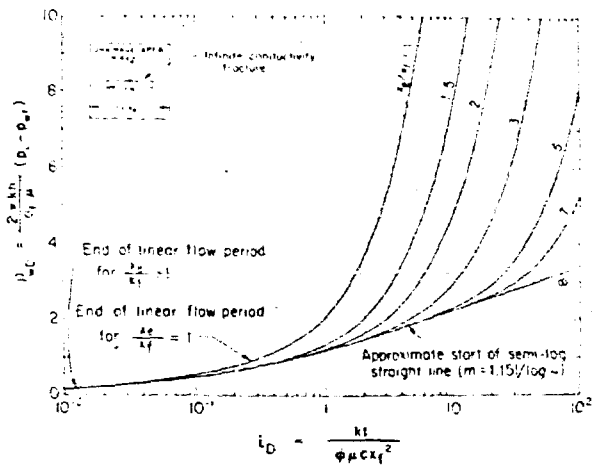

FIG. 8—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

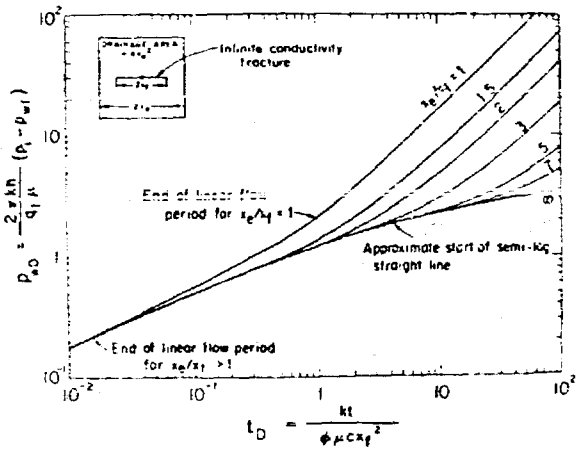

FIG. 9—p_{wD} VS t_D FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE.

by means of the Green's function and product solution method (see Ref. 14). The result is

$$p_D\left(\frac{x}{x_e}, \frac{y}{y_e}, t_{DA}\right) = 2\pi \int_0^{t_{DA}} \left[1 + 2 \sum_{n=1}^{\infty} \cdot \exp\left(-n^2\pi^2 \frac{x_e}{y_e} t'_{DA}\right) \cos n\pi \frac{y_w}{2y_e} \cdot \cos n\pi \frac{y_w+y}{2y_e}\right] \left[1 + 2 \sum_{n=1}^{\infty} \exp\left(-n^2\pi^2 \cdot \frac{y_e}{x_e} t'_{DA}\right) \frac{\sin n\pi \frac{x_f}{2x_e}}{n\pi \frac{x_f}{2x_e}} \cos n\pi \frac{x_w}{2x_e} \cdot \cos n\pi \frac{x_w+x}{2x_e}\right] dt'_{DA} \quad \ldots\ldots\ldots (27)$$

where t_{DA} represents the dimensionless time based on the drainage area:

$$t_{DA} = \frac{kt}{\phi\mu c 4(x_e\, y_e)^2} \quad \ldots\ldots (28)$$

The pressure drop on the fracture for a vertical fracture at the center of a square ($x_e = y_e$ and $x_w = y_w$) is then given by

$$p_{wD}(t_{DA}) - 2\pi \int_0^{t_{DA}} \left[1 + 2 \sum_{n=1}^{\infty} \exp(-4n^2\pi^2 t'_{DA})\right] \left[1 + 2 \sum_{n=1}^{\infty} \exp(-4n^2\pi^2 t'_{DA}) \frac{\sin n\pi \frac{x_f}{x_e}}{n\pi \frac{x_f}{x_e}} \cdot \cos n\pi\, x_D \frac{x_f}{x_e}\right] dt'_{DA} \quad \ldots\ldots (29)$$

The pressure drops on the fracture for a uniform flux fracture and for an infinite-conductivity fracture are obtained by evaluating Eq. 29 at $x_D = 0$ and $x_D = 0.732$, respectively. The choice of the same point as in the infinite case leads to reasonable results and can be justified *a posteriori* by the method of *superposition*, presented later in this paper. Numerical values of the dimensionless pressure drop from Eq. 29 are listed vs t_{DA} in Tables 2 and 3, and have been plotted vs t_D (not t_{DA}) in Figs. 3 and 4 and Figs. 8 and 9, respectively, for various values of the x_e/x_f ratio. This ratio is used instead of Russell and Truitt's[8] fracture penetration ratio x_f/x_e because the limiting case of a vertical fracture in a square reservoir is a vertical fracture in an infinite reservoir (Figs. 3, 4, 8, and 9), which correspond to $x_e/x_f = \infty$, whereas a zero fracture penetration ratio ($x_f/x_e = 0$) corresponds to an unfractured well in a square reservoir, which is a different problem.

Three different flow periods can be characterized for both types of fractures: a *linear* flow period occurs at early times. This corresponds to the one-half slope straight line in log-log coordinates (Figs. 4 and 9). After a period of transition, there is a *pseudoradial* flow period corresponding to the semilog straight line (Figs. 3 and 8). After a second period of transition, *pseudosteady* state occurs, which is characterized by an approximate unit slope straight line in log-log coordinates. Depending upon x_e/x_f, one or more of these different flow periods may be missing; in the total fracture penetration case ($x_e/x_f = 1$), for instance, the first transition period and the pseudoradial period do not appear, whereas only the pseudoradial period is missing for values of x_e/x_f between 1 and 3 (uniform flux fracture), or 1 and 5 (infinite-conductivity fracture).

DISCUSSION OF VERTICAL FRACTURE SOLUTIONS

A comparison has been made in Table 4, and in Figs. 11 and 12 between the subject analytical solution for the *infinite-conductivity fracture* and Russell and Truitt's results.[8] As can be seen from Figs. 11 and 12, the smaller the x_e/x_f, the closer the two solutions become at long times. The over-all agreement is good, in view of the fact that the Russell and Truitt solution is an explicit finite-difference solution for a very difficult problem. The total fracture penetration cases ($x_e/x_f = 1$) agree exactly at all times. None of the Russell-Truitt curves, however, produce the 1.1515 slope semilog

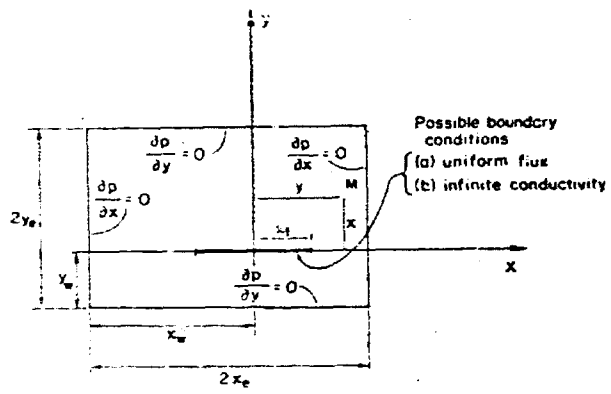

FIG. 10—VERTICAL FRACTURE IN A RECTANGULAR RESERVOIR.

straight line. This result was for many years erroneously thought by one of the authors of this study to be an inherent result of a vertical fracture, rather than an effect caused by the drainage boundaries. Furthermore, at very early times there are some discrepancies in the way the Russell-Truitt curves leave the log-log half-unit slope straight line, which makes them difficult to use with type-curve matching methods. Finally, the difference between the current analytical solution and the Russell-Truitt solution for $x_e/x_f = 10$ is much larger than that for other values of x_e/x_f. This Russell-Truitt case appears to contain an error and is not recommended for further use.

Russell and Truitt did not provide results for a vertically fractured well in an infinite reservoir, but such can be extracted from their results by *desuperposition*. The behavior of a fractured well in a square is identical with that of an infinite system containing a square array of fractured wells. The square array could be constructed by superposition of single fractured wells in infinite

TABLE 2 — p_{wD} FOR A UNIFORM FLUX VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1772	0.2481	0.3545	0.5306
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2171	0.3039	0.4340	0.6460
2.00E-04	0.0501	0.0752	0.1003	0.1504	0.2507	0.3509	0.5007	0.7392
3.00E-04	0.0614	0.0921	0.1228	0.1842	0.3070	0.4297	0.6105	0.8855
4.00E-04	0.0709	0.1063	0.1418	0.2127	0.3545	0.4957	0.6999	0.9986
5.00E-04	0.0793	0.1189	0.1585	0.2378	0.3962	0.5533	0.7756	1.0908
6.00E-04	0.0868	0.1302	0.1737	0.2605	0.4340	0.6046	0.8414	1.1686
8.00E-04	0.1003	0.1504	0.2005	0.3008	0.5007	0.6933	0.9515	1.2953
1.00E-03	0.1121	0.1681	0.2242	0.3363	0.5587	0.7686	1.0417	1.3963
1.50E-03	0.1373	0.2059	0.2746	0.4118	0.6790	0.9183	1.2145	1.5846
2.00E-03	0.1585	0.2378	0.3171	0.4752	0.7756	1.0334	1.3427	1.7211
3.00E-03	0.1942	0.2912	0.3883	0.5801	0.9261	1.2057	1.5294	1.9164
4.00E-03	0.2242	0.3363	0.4482	0.6661	1.0417	1.3336	1.6650	200565
5.00E-03	0.2507	0.3760	0.5007	0.7392	1.1355	1.4354	1.7716	2.1658
6.00E-03	0.2746	0.4118	0.5477	0.8030	1.2145	1.5199	1.8594	2.2554
8.00E-03	0.3171	0.4752	0.6297	0.9103	1.3427	1.6554	1.9990	2.3973
1.00E-02	0.3545	0.5306	0.6999	0.9986	1.4447	1.7619	2.1080	2.5078
1.50E-02	0.4342	0.6460	0.8414	1.1686	1.6344	1.9577	2.3073	2.7090
2.00E-02	0.5013	0.7393	0.9515	1.2953	1.7716	2.0981	2.4495	2.8520
3.00E-02	0.6140	0.8861	1.1183	1.4804	1.9676	2.2974	2.6505	3.0541
4.00E-02	0.7092	1.0011	1.2443	1.6159	2.1086	2.4400	2.7940	3.1980
5.00E-02	0.7935	1.0973	1.3470	1.7241	2.2201	2.5524	2.9069	3.3111
6.00E-02	0.8708	1.1819	1.4356	1.8161	2.3140	2.6469	3.0016	3.4061
8.00E-02	1.0127	1.3315	1.5893	1.9734	2.4732	2.8067	3.1618	3.5664
1.00E-01	1.1458	1.4678	1.7273	2.1129	2.6136	2.9473	3.3025	3.7072
1.50E-01	1.4652	1.7895	2.0502	2.4368	2.9381	3.2720	3.6273	4.0320
2.00E-01	1.7801	2.1047	2.3655	2.7523	3.2537	3.5876	3.9429	4.4477
3.00E-01	2.4086	2.7332	2.9941	3.3808	3.8823	4.2162	4.5715	4.9762
4.00E-01	3.0369	3.3615	3.6224	4.0092	4.5106	4.8445	5.1998	5.6045
5.00E-01	3.6652	3.9898	4.2507	4.6375	5.1389	5.4728	5.8281	6.2328
6.00E-01	4.2935	4.6181	4.8790	5.2658	5.7672	6.1011	6.4564	6.8512
8.00E-01	5.5501	5.8748	6.1357	6.5224	7.0239	7.3578	7.7131	8.1178
1.00E+00	6.8068	7.1314	7.3923	7.7791	8.2805	8.6144	8.9697	9.3744
1.50E+00	9.9484	10.2730	10.5339	10.9207	11.4221	11.7560	12.1113	12.5160
2.00E+00	13.0900	13.4146	13.6755	14.0623	14.5637	14.8976	15.2529	15.6576
3.00E+00	19.3732	19.6978	19.9587	20.3455	20.8469	21.1808	21.5361	21.9408
4.00E+00	25.6563	25.9810	26.2418	26.6286	27.1301	27.4639	27.8193	28.2240
5.00E+00	31.9395	32.3641	32.5250	32.9118	33.4132	33.7471	34.1024	34.5072
6.00E+00	38.2227	38.5473	38.8082	39.1950	39.6964	40.0303	40.3856	40.7904
8.00E+00	50.7891	51.1137	51.3746	51.7614	52.2628	52.5967	52.9520	53.3567

mediums in the same way a well in a closed square was constructed by Matthews *et al.*[18] and by Earlougher *et al.*[19] We realize that the pressure drop at a great distance from a fractured well produced at constant rate is essentially identical with the pressure drop caused by an unfractured well. Thus, the behavior of a fractured well in a closed square may be approximated by generating the drainage boundaries with unfractured wells, if x_e, y_f is large enough. This simple approach can also be used to extract the behavior of a fractured well in an infinite medium from that of a fractured well in a closed square. This can be stated as follows: the p_D for a fractured well in an infinite medium is equal to the p_D for a fractured well in a closed square, less the p_D for an unfractured well in a closed square, plus the p_D for an unfractured well in an infinite medium. The method has been applied to both the current analytical solutions and Russell-Truitt solutions for an infinite-conductivity fracture in a closed square reservoir (Table 4 and Fig. 13). The data for an unfractured well in a

TABLE 3 — p_{wD} FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A SQUARE

t_{DA} / x_e/x_f	1.00	1.50	2.00	3.00	5.00	7.00	10.00	15.00
1.00E-04	0.0354	0.0532	0.0709	0.1063	0.1765	0.2433	0.3356	0.4735
1.50E-04	0.0434	0.0651	0.0868	0.1302	0.2145	0.2928	0.3996	0.5590
2.00E-04	0.0501	0.0752	0.1003	0.1502	0.2456	0.3327	0.4509	0.6278
3.00E-04	0.0614	0.0921	0.1228	0.1832	0.2955	0.3962	0.5328	0.7379
4.00E-04	0.0709	0.1063	0.1417	0.2104	0.3356	0.4471	0.5987	0.8259
5.00E-04	0.0793	0.1139	0.1582	0.2338	0.3697	0.4904	0.6549	0.9000
6.00E-04	0.0868	0.1302	0.1730	0.2545	0.3996	0.5284	0.7042	0.9642
8.00E-04	0.1003	0.1502	0.1989	0.2901	0.4509	0.5939	0.7889	1.0718
1.00E-03	0.1121	0.1676	0.2212	0.3204	0.4945	0.6496	0.8603	1.1600
1.50E-03	0.1373	0.2040	0.2671	0.3821	0.5833	0.7631	1.0027	1.3296
2.00E-03	0.1585	0.2338	0.3041	0.4315	0.6549	0.8536	1.1129	1.4560
3.00E-03	0.1942	0.2818	0.3633	0.5104	0.7691	0.9953	1.2792	1.6405
4.00E-03	0.2242	0.3204	0.4107	0.5738	0.8603	1.1050	1.4037	1.7750
5.00E-03	0.2507	0.3533	0.4509	0.6278	0.9367	1.1947	1.5033	1.8808
6.00E-03	0.2746	0.3821	0.4863	0.6753	1.0027	1.2707	1.5862	1.9681
8.00E-03	0.3171	0.4315	0.5470	0.7569	1.1129	1.3948	1.7196	2.1071
1.00E-02	0.3545	0.4735	0.5987	0.8259	1.2030	1.4941	1.8248	2.2158
1.50E-02	0.4342	0.5595	0.7043	0.9642	1.3754	1.6800	2.0189	2.4146
2.00E-02	0.5013	0.6295	0.7891	1.0718	1.5033	1.8152	2.1583	2.5564
3.00E-02	0.6140	0.7445	0.9239	1.2352	1.6896	2.0092	2.3567	2.7572
4.00E-02	0.7092	0.8406	1.0316	1.3592	1.8256	2.1492	2.4989	2.9006
5.00E-02	0.7935	0.9254	1.1235	1.4607	1.9342	2.2600	2.6110	3.0133
6.00E-02	0.8708	1.0030	1.2054	1.5486	2.0264	2.3536	2.7053	3.1081
8.00E-02	1.0127	1.1452	1.3521	1.7015	2.1838	2.5124	2.8649	3.2682
1.00E-01	1.1458	1.2784	1.4872	1.8392	2.3234	2.6527	3.0055	3.4089
1.50E-01	1.4652	1.5979	1.8081	2.1619	2.6474	2.9771	3.3301	3.7337
2.00E-01	1.7801	1.9128	2.1231	2.4772	2.9629	3.2926	3.6457	4.0493
3.00E-01	2.4086	2.5413	2.7516	3.1057	3.5915	3.9212	4.2743	4.6778
4.00E-01	3.0369	3.1696	3.3799	3.7341	4.2198	4.5495	4.9026	5.3061
5.00E-01	3.6652	3.7979	4.0082	4.3624	4.8481	5.1778	5.5309	5.9345
6.00E-01	4.2935	4.4262	4.6366	4.9907	5.4764	5.8061	6.1592	6.5628
8.00E-01	5.5501	5.6829	5.8932	6.2473	6.7331	7.0628	7.4159	7.8194
1.00E+00	6.8068	6.9395	7.1498	7.5040	7.9897	8.3194	8.6725	9.0761
1.50E+00	9.9484	10.0811	10.2914	10.6456	11.1313	11.4610	11.8141	12.2177
2.00E+00	13.0900	13.2227	13.4330	13.7872	14.2729	14.6026	14.9557	15.3592
3.00E+00	19.3732	19.5059	19.7162	20.0703	20.5561	20.8858	21.2389	21.6424
4.00E+00	25.6563	25.7891	25.9994	26.3535	26.8393	27.1690	27.5220	27.9256
5.00E+00	31.9395	32.0722	32.2826	32.6367	33.1224	33.4521	33.8052	34.2088
6.00E+00	38.2227	38.3554	38.5658	38.9199	39.4056	39.7353	40.0884	40.4920
8.00E+00	50.7891	50.9218	51.1321	51.4863	51.9720	52.3017	52.6548	53.0584

closed square were taken from Table 1, Ref. 19. It was found that desuperposition of the analytical solution for a closed square yields a very good approximation of the analytical solution for an infinite reservoir, for x_e/x_f values of 2, 5, and 10/3. This justifies *a posteriori* the choice of $x_{fD} = 0.732$ for representing the wellbore pressure for an infinite-conductivity fracture in the finite-reservoir case. x_e/x_f ratios of 10/7 and 1 gives p_D values that are much too large, implying that desuperposition cannot be used because the fracture is too close to the square boundary. The $x_e/x_f = 10$ case yields p_D values by desuperposition that are far too small. It is likely that the Russell and Truitt results have a small, almost constant error for this case. It should be noted, however, that the Russell and Truitt desuperposed solution for an infinite reservoir does have a slope of 1.151 when plotted on semilog coordinates, although their solutions for the closed square did not.

An interesting interpretation of the behavior of a vertically fractured well can be made in terms of an equivalent unfractured system. Prats[5] has shown that an infinite-conductivity vertical fracture, producing an incompressible fluid from a closed circular reservoir *at steady state*, is equivalent to an unfractured well with an effective radius equal to a quarter of the total fracture length, for ratios of the reservoir radius to the fracture half length greater than 2. The same is true, within 7 percent,

TABLE 4 — COMPARISON BETWEEN ANALYTICAL AND FINITE-DIFFERENCE WELLBORE PRESSURES FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE AT THE CENTER OF A CLOSED SQUARE

t_{DA} / x_e/x_f=1	1		10/7		2	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.0 E-04	0.0354	0.0355	0.0506	0.0506	0.0709	0.0709
2.0 E-04	0.0501	0.0501	0.0716	0.0716	0.1003	0.1003
5.0 E-04	0.0793	0.0793	0.1132	0.1107	0.1582	0.1527
8.0 E-04	0.1003		0.1431		0.1989	
1.0 E-03	0.1121	0.1121	0.1598	0.1528	0.2212	0.2092
2.0 E-03	0.1585	0.1585	0.2233	0.2111	0.3041	0.2870
5.0 E-03	0.2507	0.2507	0.3386	0.3220	0.4509	0.4326
8.0 E-03	0.3171	0.3171	0.4142	0.3982	0.5470	0.5306
1.0 E-02	0.3545	0.3545	0.4548	0.4398	0.5987	0.5836
2.0 E-02	0.5013	0.5014	0.6062	0.5969	0.7891	0.7755
5.0 E-02	0.7935	0.7936	0.8973	0.8947	1.1235	1.1051
8.0 E-02	1.0127	1.0127	1.1160	1.1145	1.3521	1.3309
1.0 E-01	1.1458	1.1457	1.2489	1.2477	1.4872	1.4654
2.0 E-01	1.7801	1.7797	1.8832	1.8818	2.1231	2.1003
5.0 E-01	3.6652	3.6648	3.7683	3.7668	4.0082	3.9853
8.0 E-01	5.5501	5.5498	5.6532	5.6517	5.8932	5.8702
1.0 E+00	6.8068	6.8064	6.9099	6.9034	7.1498	7.1269
2.0 E+00	13.0900	13.0696	13.1930	13.1916	13.4350	13.4161
5.0 E+00	31.9395		32.0426		32.2826	
8.0 E+00	50.7891		50.8922		51.1321	

t_{DA} / x_e/x_f=1	10/3		5		10	
	Analytical	Finite Dif.	Analytical	Finite Dif.	Analytical	Finite Dif.
1.0 E-04	0.1181	0.1182	0.1765	0.1772	0.3256	0.3545
2.0 E-04	0.1666	0.1671	0.2456	0.2476	0.4509	0.4715
5.0 E-04	0.2578	0.2463	0.3697	0.3575	0.6549	0.6395
8.0 E-04	0.3187		0.4509		0.7889	
1.0 E-03	0.3514	0.3318	0.4945	0.4780	0.8603	0.8013
2.0 E-03	0.4711	0.4480	0.6549	0.6390	1.1129	1.0171
5.0 E-03	0.6830	0.6586	0.9367	0.9164	1.5033	1.2697
8.0 E-03	0.8220	0.7951	1.1129	1.0872	1.7196	1.5732
1.0 E-02	0.8958	0.8668	1.2030	1.1742	1.8248	1.6735
2.0 E-02	1.1550	1.1167	1.5033	1.4659	2.1583	1.9970
5.0 E-02	1.5552	1.5045	1.9342	1.8894	2.6110	2.4430
8.0 E-02	1.7984	1.7442	2.1858	2.1372	2.8649	2.6958
1.0 E-01	1.9366	1.8817	2.3234	2.2766	3.0055	2.8361
2.0 E-01	2.5751	2.5189	2.9629	2.9154	3.6457	3.4757
5.0 E-01	4.4602	4.4039	4.8481	4.8004	5.5309	5.3607
8.0 E-01	6.3452	6.2889	6.7331	6.6853	7.4159	7.2456
1.0 E+00	7.6018	7.5455	7.9897	7.9419	8.6725	8.5023
2.0 E+00	13.8850	13.8287	14.2729	14.2252	14.9557	14.7856
5.0 E+00	32.7345		33.1224		33.8052	
8.0 E+00	51.5841		51.9720		52.6548	

for a compressible fluid at *steady* or *pseudosteady* state.[6] We can see that these results apply to a vertically fractured well in an infinite reservoir during the *pseudoradial* period, because Eq. 25 can be written as

$$p_{wD}(t_D) = \frac{1}{2}\left[\ln\left(\frac{kt}{\phi\mu c\left(\frac{x_f}{2}\right)^2}\right) + 0.80907\right]. \quad \ldots\ldots\ldots \quad (30)$$

The effective well radius for an infinite-conductivity vertical fracture in an infinite reservoir is thus exactly one-fourth the total fracture length. The effective radius for an infinite-conductivity vertical fracture in a closed square reservoir at *pseudosteady state* may be obtained from the general pseudosteady-state depletion equation presented by Brons and Miller,[20] which, in the present case, can be expressed as

$$p_{wD} = 2\pi\, t_{DA} + \ln \frac{4(x_f/r'_w)}{\sqrt{e^{\gamma} C_A}} \frac{x_e}{x_f}, \quad \ldots \quad (31)$$

where C_A is the shape factor for a well in a square, and r'_w is the effective well radius. Effective radii computed from the current analytical solution and from the Russell and Truitt solution are compared in Fig. 14 with the results of Prats *et al.*[6] for various values of x_f/x_e (x_f/x_e is used for convenience in this case). Surprisingly, variations of the radii as a function of x_f/x_e are different in the Prats *et al.* results. Again, the result for x_f/x_e = 0.1 in Russell-Truitt's case is inconsistent with other results.

Comparison was also made between the subject solution and the analytical results of van Everdingen and Meyer[11] for an infinite-conductivity fracture in an infinite reservoir. Although not shown, results do not compare well. The van Everdingen and Meyer solution is correct during the initial linear flow period. But it yields a semilog straight line of slope 0.576 per $\log_{10}$ cycle, instead of 1.151 per $\log_{10}$ cycle as in the subject study, or as in the Russell and Truitt[8] desuperposed solution. It is not recommended that this solution be used in the pseudoradial flow period. Either the current analytical solution, or the desuperposed Russell-Truitt solution for a fractured well in an infinite medium may be used.

NOMENCLATURE

C_A = pseudosteady-state shape factor for a well at the center of a square[19] = 30.86

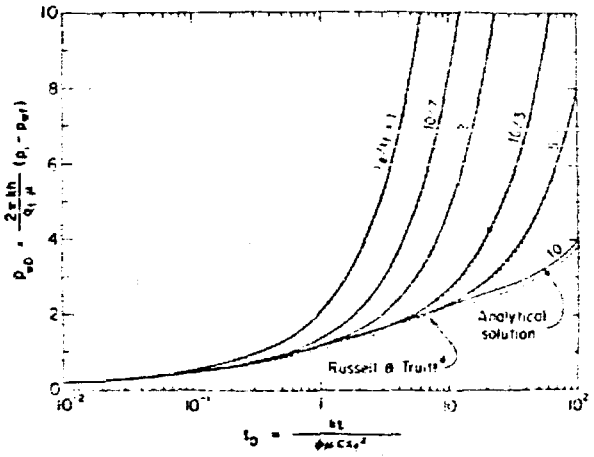

FIG. 11 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A SQUARE.

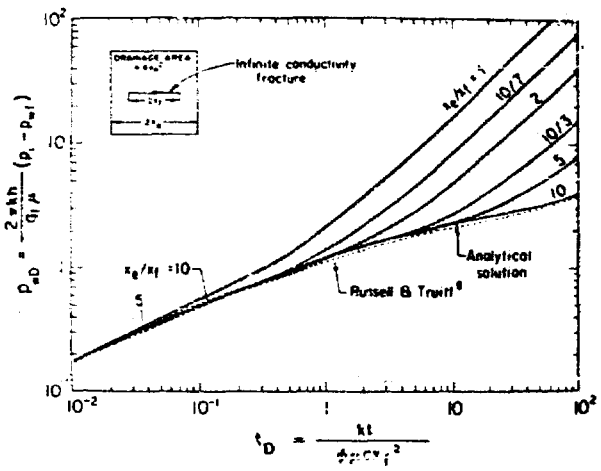

FIG. 12 — COMPARISON OF ANALYTICAL SOLUTION AND RUSSELL AND TRUITT SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN A CLOSED SQUARE.

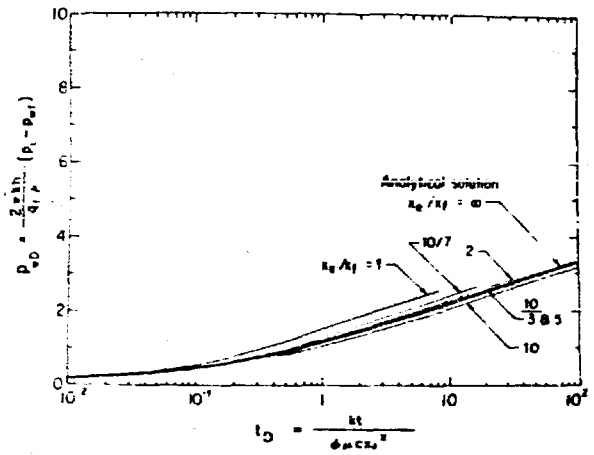

FIG. 13 — DESUPERPOSITION OF RUSSELL AND TRUITT RESULTS TO OBTAIN A VERTICALLY FRACTURED WELL IN AN INFINITE RESERVOIR AND COMPARISON WITH THE SUBJECT ANALYTICAL SOLUTION FOR AN INFINITE-CONDUCTIVITY VERTICAL FRACTURE IN AN INFINITE RESERVOIR.

h = formation thickness
k = formation permeability
M = number of vertical fracture elements for generating an infinite-conductivity fracture
p = pressure
p_i = initial reservoir pressure
p_D = dimensionless pressure
q_f = total withdrawal rate from fracture
q_m = flux per unit area in vertical fracture elements
r = distance to fracture axis
r_D = dimensionless distance to fracture axis, based on fracture half length
r'_w = effective well radius
t = flowing time
t_D = dimensionless time based on the fracture half length
t'_D = dummy variable of integration
t_{DA} = dimensionless time based on drainage area
x, y = space coordinates
x_D, y_D = dimensionless coordinates based on the fracture half length
x_e, y_e = rectangular reservoir half dimensions
x_f = fracture half length
x_w, y_w = fracture axis coordinates
γ = Euler's constant = 0.5772
η = diffusivity constant
μ = fluid viscosity

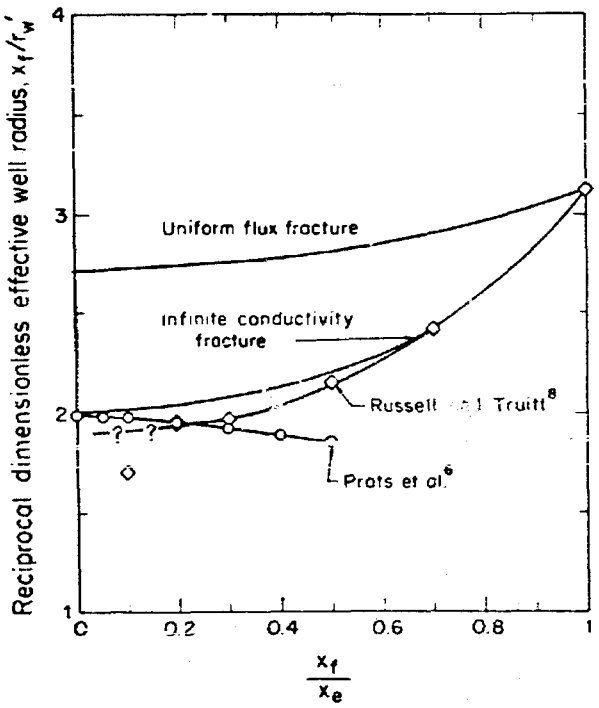

FIG. 14—COMPARISON OF RECIPROCAL DIMENSIONLESS EFFECTIVE WELL RADIUS, x_f/r'_w.

s = pseudo skin function, defined by Eq. 14
x = dummy variable of integration
ϕ = formation porosity

SPECIAL FUNCTIONS

Inverse tangent function:

$$\arctan(x) = \tan^{-1}(x)$$

Exponential integral:

$$-Ei(-x) = \int_0^x \frac{e^{-u}}{u}\, du$$

Error function:

$$erf(x) = \frac{2}{\sqrt{\pi}} \int_0^x e^{-u^2}\, du$$

Complementary error function:

$$erfc(x) = 1 - erf(x)$$

Units: CGS units are used throughout this study.

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***

GASWELL Program

User's Manual

2/79

Gas Well Performance Simulation Program

GARRETT COMPUTING SYSTEMS

DALLAS, TEXAS

GAS WELL PERFORMANCE SIMULATOR

Program GASWELL

FEBRUARY 1979

GARRETT COMPUTING SYSTEMS

PREFACE

This manual contains detailed instructions for the use of the subject program in the applications for which it was designated. It is written for engineers, geologists and other professional employees within the petroleum industry. They need not be computer programmers. However, familiarity with the computing system on which this program has been placed is recommended.

This program is a part of an expanding library of time-sharing programs developed by Garrett Computing Systems, Inc. for use by its subscribers. All programs in the GCS library are run-only programs, meaning that they cannot be listed or permanently modified by the user. The terms under which they are made available may vary between programs or may vary with a given program from time to time. Garrett Computing Systems reserves the right to change these terms at its discretion. Questions regarding use of the program library should be directed to:

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Telephone: 741-1026 (A/C 214)

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TECHNICAL NOTES

ABOUT THE PROGRAM

General

The GASWELL program is used to forecast production from hydraulically fractured gas wells. Reservoir and fracture descriptions are provided by the user along with wellhead pressure and producing rate constraints. The program computes values for producing rate, wellhead pressure, cumulative production and cumulative recovery. Additional features in the program allow the user to compare production history or pressure buildup tests to computed values on the basis of either wellhead pressure or producing rate, and thus determine whether the input reservoir and fracture descriptions are satisfactory.

Input

Input data forms are available on which the user's data should be recorded. These data are subsequently placed in an input file prior to running the GASWELL program. Data for only one case can be placed in a single file. If more than one case is to be run, each case should be placed in a separate file.

Output

The GASWELL program prepares a two-page tabular report for production forecasts. The report is generally stored in an output file which the program creates under a name selected by the user. A description of each page is as follows:

First Page - The first page contains a recap of the input data with the computed value for initial total system compressibility. The information is subdivided into categories for reservoir properties, reservoir geometry, fluid properties, and flowstream data.

Second Page - This page, entitled "Predicted Performance", contains a printout by time frame of the forecasted variables. The values tabulated on this page are time, flowing wellhead pressure, flowing bottom-hole pressure, average shut-in reservoir pressure, producing gas rate, cumulative production, cumulative percent recovery, and Z-factor at average reservoir conditions. If the user exercises the option of providing constraints from the terminal during execution, the forecasted values are printed directly on the terminal in addition to being placed in the output data file.

When a comparison based on observed history is performed, the output is different from that of a forecast. As with a production forecast, a recap of the input data is provided on the first page of output. The second page, entitled

"Performance Comparison", contains a table of computed and observed values versus time. The tabulated values are time, observed wellhead pressure, calculated wellhead pressure, observed rate, and calculated rate. In addition to being placed in the output data file, the performance comparison report is also printed on the user's terminal.

Processing Technique

The processing technique used by the GASWELL program is outlined below:

1. All input data is read and converted to standard units.

2. The initial total system compressibility is computed.

3. Real gas pseudo-pressures are computed for pressures ranging up to the initial reservoir pressure based on the gas gravity and computed values for gas viscosity and Z-factor.

4. Internal tables are generated for dimensionless pressure drop versus dimensionless time based on the user's reservoir geometry. These solution tables are discussed further in the Technical Notes section.

5. A time-step is taken and the deliverable rate against the scheduled wellhead pressure is computed. If this rate is in excess of the maximum allowable rate, the wellhead pressure corresponding to the allowable rate is computed.

6. Production for the time interval and the flowing bottom-hole pressure are both calculated based on the rate determined in Step 5.

7. The average reservoir pressure is computed by material balance based on the production increment established in Step 6.

8. Cumulative percent recovery and Z-factor at reservoir conditions are computed.

9. The above process is repeated from Step 5 until the ending time or minimum producing rate is reached.

10. The output report is printed.

Principal Features

The following features are included in the GASWELL program.

1. Production forecasts can be obtained based on production constraints such as minimum wellhead pressure and maximum allowable rate. Production constraints can be varied as a function of time.

2. The forecast may be started at any time subsequent to the specified initial date. In addition, the user may specify the desired output frequency.

3. Observed wellhead pressures or production rates may be compared to computed values. Short-term or long-term data may be used.

4. A rectangular drainage shape may be specified along with the well location within the drainage area.

5. Either uniform flux or infinite conductivity fractures may be considered.

6. Real gas pseudo pressures are computed based on input gas gravity. Adjustments to gas properties can be made for the presence of H_2S, CO_2 and N_2.

7. An interactive mode exists which allows the user to control the progress of either production forecasts or production comparisons.

Assumptions

The following assumptions have been incorporated into the calculations.

1. The fracture is vertical.

2. The fracture can be characterized either as possessing infinite conductivity or having uniform mass flux within the fracture plane.

3. The reservoir matrix has constant properties throughout.

4. A single producing layer exists of uniform thickness.

5. The wellbore is located at the center of the fracture.

6. The fracture is paraliel to the drainage boundary.

7. The drainage boundary is either square or rectangular.

8. Fluid flow within the reservoir is single-phase gas.

Program Calculation Step Size Selection

For increased accuracy in its internal predictive calculations the program selects an initial time-step size of one-half day, then doubles this size for each succeeding step until a step size of one month is reached. This value is then held constant until three years have elapsed since the calculations began. Quarterly steps are taken until a total of six years has passed, whereupon the step size is set at six months for the duration of the run.

The program will automatically alter these time step sizes to accommodate output dates specified on lines 701-799 (or input as response to question on output frequency). Thus the user may override the built-in time steps by specifying each desired interval on the 701-799 lines.

PREPARATION OF DATA

Form Available

A GASWELL input form has been developed for recording all necessary input data. A copy has been included at the back of this manual. Additional copies may be reproduced from this manual or ordered in pad form from GCS.

Multiple Cases

Data for each case (one input data sheet) should be placed in a separate computer file before processing.

Line Numbers

The line numbers shown on the input data form serve two purposes. They tell the program the nature of the data on the line and permit proper sequencing before processing. Only the line numbers indicated on the form or in this chapter may be used.

Data Format

With the exception of lines 101-103, all input is in free form. This means that the basic requirement for spacing of data is that each word entry be separated from the next by at least one blank space. Inclusion of decimal points is permitted. All data spaces must be filled in on each line. Data items not used must contain a zero instead of a blank.

Lines 101-103 (Run Description)

```
101  YOURWELL NO. 3
102  ROUNDHOUSE FIELD
103  FREMONT CO., WYOMING
```

These three lines contain heading information for the printout. Recommended information for these lines includes well name and number, field and zone, and county and state. Any alphanumeric descriptions can be placed on these lines provided, however, that the maximum number of characters, including blanks, does not exceed 24 on any line.

Line 200 (Reservoir Data)

	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation, %	Temperature of Zone, °F
200	.53	4.7	115	53	197

This line contains the basic reservoir parameters. All five items on this line are required and are described as follows:

1. Permeability, Md. - Enter the matrix permeability of the producing interval.

2. Porosity, % - Specify the total porosity of the producing interval as a percent of the bulk volume.

3. Net Pay, Feet - Enter the net thickness of the producing interval. The program assumes that the fracture extends from the top to the bottom of the net interval and that the interval is of constant thickness throughout the drainage area.

4. Liquid Saturation, % - Enter the total liquid saturation for the producing interval. The program assumes this value to be constant throughout the drainage area and for the life of the project.

5. Temperature of Zone, Degrees F - Show the average reservoir temperature. The program assumes this value to be constant for the project life.

Line 210 (Fracture Data)

	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210	500	2640	2640	1320	1320

All items on this line are required. The data on this line describe the fracture length, the size of the drainage area and the position of the fracture within the drainage area. Note that the fracture must be oriented in the X-direction. Refer to Figure 1 for the discussion of the following items:

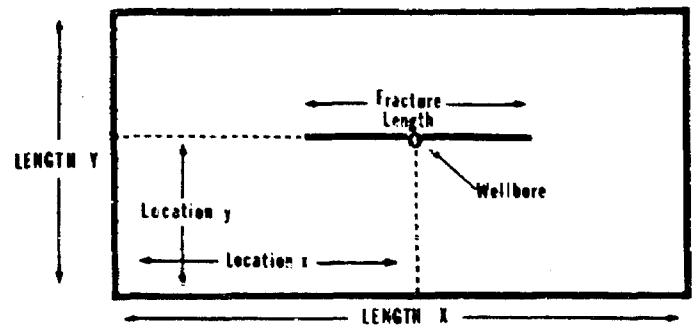

Fig. 1

1. Fracture Length, Feet - Enter the tip-to-tip fracture length in feet. If a value less than one foot is entered, the program will assume that the item entered is a wellbore radius and that no fracture exists.

2. Drainage Area Length X, Feet - Enter the length corresponding to length X in Figure 1. This is the total length of the drainage area in the X-direction.

3. Drainage Area Length Y, Feet - Enter the length corresponding to length Y in Figure 1. This is the total length of the drainage area in the Y-direction.

4. Well Location x, Feet - Enter the distance corresponding to location x in Figure 1. This is the x-component of the wellbore location within the drainage area.

5. Well Location y, Feet - Enter the distance corresponding to location-y in Figure 1. This is the y-component of the wellbore location within the drainage area.

Line 220 (Flowstream Data)

	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (Inches)	Liquid Comp. (V/MMV/PSI)
220	1.995	0	9750	0	3.8

This line must always be present in a data file. The items are described as follows:

1. Flowstream O. D., Inches - Enter the outer diameter of the producing fluid stream within the wellbore. For tubing flow this entry will be the tubing I. D. For annular flow this entry will be the casing I. D. If wellbore pressure losses are not being considered, enter a zero.

2. Flowstream I. D., Inches - Enter the inner diameter of the producing fluid Stream. This entry only applies to annular flow and corresponds to the O. D. of the tubing. For tubing flow enter a zero for this item. If wellbore pressure losses are not being considered, enter a zero.

3. Zone Depth, Feet - Enter the depth to the mid-point of the producing interval. If wellbore pressure losses are not being considered, enter a zero.

4. Pipe Roughness, Inches - Specify the absolute pipe roughness in inches. If a zero is entered the program will use a default value of 0.0018 inches in the wellbore hydraulics calculations.

5. Liquid Comp., V/MMV/PSI - This compressibility should reflect that part of the total system compressibility not accounted for by the gas compressibility. This entry is -

$$C = S_l C_l + C_f$$

where,

S_l = liquid saturation, percent

C_l = actual liquid compressibility, V/MMV/PSI

C_f = formation compressibility, V/MMV/PSI

The importance of this entry depends on the magnitude of the gas compressibility. If the gas compressibility is large, this item will not significantly affect the calculations.

Line 230 (Fluid Data)

	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230	.68	.93	.12	1.0	0

This line is required in all input data files. The entries are described as follows:

1. Gas Gravity, (Air=1) - Enter the specific gravity of the gas.

2. Liquid Gravity, (Water=1) - Enter the specific gravity of the liquid. If the liquid consists of both condensate and water, enter a weighted specific gravity based on the proportion of each liquid in the produced stream. If no liquid is present in the flowstream, enter a zero.

3. H2S Diluent, Mol % - Enter the hydrogen sulfide content of the produced gas. When used, values for N_2 and CO_2 should also be entered.

4. CO2 Diluent, Mol % - Enter the carbon dioxide content of the produced gas. When used, values for H_2S and CO_2 should also be entered.

5. N2 Diluent, Mol % - Enter the nitrogen content of the produced gas.

Line 240 (Optional Data)

	Non-Darcy Flow[1] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
240	0	0	1	14.025	60

The use of this line is optional. The entries are described as follows:

1. Non-Darcy Flow Coefficient, Days/MCF - This entry enables the user to introduce a rate-dependent dimensionless pressure drop into the calculations. This is normally done when it has been observed that the skin factor is rate-dependent. The coefficient represented here is the slope of a plot of skin factor versus producing rate.

2. Skin Factor, Dimensionless - This entry is sometimes used to approximate the increased flow efficiency of a fracture by a skin factor. This should only be done when a wellbore radius has been entered on line 210. If a fracture length has been entered on line 210, this entry will normally be zero.

3. Fracture Type - Enter a zero for an infinite conductivity fracture. Enter a 1 for a uniform flux fracture. If line 240 is not being used, the program will default to use of an infinite conductivity fracture.

4. Standard Pressure, PSIA - Enter the standard pressure. If no entry is supplied the program will assume a value of 14.65 psia.

5. Standard Temperature, Degrees F - Enter the standard temperature. If no entry is supplied the program will assume a value of 60 degrees F.

Line 700 (Initial Time and Pressure)

	Beginning Date[6] Mo.	Day	Year	Initial Reservoir,PSIG	Minimum[7] Rate MCF/D
700	1	1	79	3975	1

Line 700 is required. The entires are described as follows:

1. Beginning Date, Month-Day-Year - This entry establishes the beginning time of the run. The reservoir pressure at this time should be uniform throughout the drainage area.

2. Initial Reservoir Pressure, PSIG - Enter the reservoir pressure corresponding to the beginning rate.

3. Minimum Rate, MCF/D - Specify a rate which will serve as a cutoff for the calculations. This rate may be regarded as the economic limit for the well. This value may be negative, which can be useful in preventing the calculations from stopping during a comparison run when the user is trying to match very low rates (or zero rates in the case of a build-up test).

Line 701-799(Limiting Data)

	Limiting Date[6] Mo.	Day	Year	Limiting Wellhead Flow,PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701	1	1	80	900	3000	5.7	90
702	6	1	81	300	3000	9	90
703	1	1	83	300	3000	16	90

These lines are used to supply the program with information to govern the producing conditions. The information is time-scheduled as described below:

1. Limiting Date, Month-Day-Year - This entry supplies the time through which the subsequent information on the line will apply. The first date supplied here must be later than the beginning date specified on line 700. Note: The day can be entered as a decimal fraction for instances where limiting values change within the span of a day.

2. Limiting Wellhead Flowing Pressure, PSIG - This entry represents the minimum permissible wellhead pressure. If the well rate is restricted, due to an allowable for example, the calculated wellhead pressure will always be higher than this input value. If the well is producing at maximum capacity the wellhead pressure will be maintained at the specified value as the rate declines. If observed data is being entered for comparison purposes, enter the observed wellhead pressure.

3. Limiting Gas Rate, MCF/D - This entry represents the maximum permissible gas production rate. The well will be limited to this rate even if flow capacity against the limiting wellhead pressure is greater. If observed data is being entered for comparison purposes, enter the observed producing rate.

4. Liquid Rate, Bbls./MMCF - The program will adjust the wellbore hydraulics calculations to account for the presence of liquids in the flowstream. It it is desired to increase the wellbore pressure gradient to account for liquids, enter the total liquid rate in Bbls./MMCF. Otherwise, enter a zero.

5. Wellhead Temperature, Degrees F - Enter the wellhead flowing temperature.

Up to 99 lines of limiting data may be included in a single file.

RUNNING THE PROGRAM

Setting Up an Input Data File

The user must place his input data into a timesharing file prior to running program GASWELL. Data for only one case may be placed in a single file.

Program Operation and Output

There are basically four ways GASWELL can be run:

1. As a prediction with future production constraints specified on lines 701-799 in the input data file.

2. As a prediction with future production constraints specified interactively on the terminal during execution.

3. As a comparison of computed to observed wellhead pressures given specified producing rates, with the tests input on lines 701-799.

4. As a comparison of computed to observed producing rates given specified wellhead pressures, with these tests input on lines 701-799.

Since each of these methods requires slightly different procedures to run, the following examples were prepared (one for each of the four methods above) to illustrate the dialogue required to use these methods and the resulting output for each. Comments with respect to the circled numbers are as indicated below.

In all cases these output reports are located in user-named output files and can be listed on the terminal after execution of the program.

Every GASWELL execution will generate two pages of output. The first output page will be the same regardless of which type run is being made. For this reason page one will be discussed first and omitted from the individual examples.

1. The first three lines printed in the upper left-hand corner are the information contained on input data lines 101-103.

2. The following items appear under the heading "Reservoir Properties":

   a) Date - The date on the 700-line of the input data. This is the initial time-zero date.

   b) Pressure, Psig - The input reservoir pressure at the initial date. This pressure is assumed to be uniform throughout the drainage area.

GENERAL PAGE ONE EXAMPLE
OUTPUT FOR EACH GASWELL (1)
CALCULATION MADE

1/26/79 10:25:00

F R A C T U R E D G A S W E L L

P R O D U C T I O N P E R F O R M A N C E

RESERVOIR PROPERTIES (2)

DATE	12-31.00-78	LIQUID SAT., PCT.	40.0
PRESSURE, PSIG	3000.0	TEMPERATURE, DEG. F.	200.0
PERMEABILITY, MD.	1.000	TOTAL COMP., V/MMV/PSI	176.9
POROSITY	25.0	NON-DARCY FLOW COEFF.	0.0
NET PAY, FT.	50.0	SKIN	0.0

RESERVOIR GEOMETRY (3)

FRACTURE LENGTH, FT.	400.0	FRACTURE TYPE	I.C.
X-LENGTH, FT.	2640.	X-LOCATION, FT.	1320.
Y-LENGTH, FT.	2640.	Y-LOCATION, FT.	1320.

FLUID PROPERTIES (4)

GAS GRAVITY	0.600	H2S, MOL. PCT.	0.00
LIQUID GRAVITY	0.000	CO2, MOL. PCT.	0.00
STANDARD PRESSURE, PSIA	14.65	N2, MOL. PCT.	0.00
STANDARD TEMP., DEG. F.	60.0		

FLOWSTREAM DATA (5)

FLOWSTREAM O.D., IN.	1.995	TOTAL DEPTH, FT.	7000.
FLOWSTREAM I.D., IN.	0.000	ABS. PIPE ROUGH., IN.	0.00180

c) Permeability, Md. - The input reservoir matrix permeability.

d) Porosity, % - The input reservoir matrix porosity.

e) Net Pay, Ft. - Input net pay in the producing interval.

f) Liquid Saturation, % - Combined input hydrocarbon and water saturation in the drainage area.

g) Temperature, Degrees F - The average input reservoir temperature.

h) Total Compressibility, V/MMV/PSI - The computed total compressibility at initial reservoir conditions.

i) Non-Darcy Flow Coefficient - The input non-Darcy flow coefficient. Units are MM Days/Mcf.

j) Skin - The input skin factor.

3. The following items appear under the heading "Reservoir Geometry":

a) Fracture Length, Ft. - The input tip-to-tip fracture length. If a fracture is not being used, this item will be shown as a wellbore radius.

b) X-length, Ft. - The drainage area X length input on line 210.

c) Y-Length, Ft. - The drainage area Y length input on line 210.

d) Fracture Type - The input fracture type will be printed as "I.C." for infinite conductivity fractures and "U.F." for uniform flux fractures.

e) X-Location Ft. - The wellbore x location input on line 210.

f) Y-Location, Ft. - The wellbore y location input on line 210.

4. The following items appear under the heading "Fluid Properties":

a) Gas Gravity - The input gas specific gravity (Air=1.0).

b) Liquid Gravity - The input liquid specific gravity (Water=1.0).

c) Standard Pressure - The input standard pressure, psia.

d) Standard Temperature, Degrees F - The input standard temperature.

e) H2S, CO2, N2, Mol. Percent - The input mol percentage of diluents.

5. The following items follow the heading "Flowstream Data":

a) Flowstream O.D., Inches - The input O.D. of the flowstream. This will be the tubing I.D. for tubing flow, or the casing I.D. for annular flow.

b) Flowstream I.D., Inches - The input I.D. of the flowstream. This will be 0 for tubing flow, or the tubing O.D. for annular flow.

c) Total Depth, Ft. - The input depth to the mid-point of the producing interval.

d) Absolute Pipe Roughness, In. - The input absolute pipe roughness.

Example 1
Production Forecast

In this example the user wishes to predict the performance of the well and has scheduled all future production constraints by using lines 701-799 in the input data file. The execution dialogue is presented first, followed by the second page of the output report.

```
RUN GASWELL (1)
GASWEL @ 10:56:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX1 XX1OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?0 (3)


 ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
 OUTPUT TIME INTERVALS (MOS.) --?1 1 79 12 (4)


 WANT TO ALTER INPUT DATA --?YES (5)
```

```
 LINE, WORD, VALUE --?701 4 1000


 LINE, WORD, VALUE --?0 0 0


 WANT TO ALTER INPUT DATA --?NO

 FILE - XX1OUT   SAVED. (6)
READY.
```

1. This command retrieves the GASWELL program from the GCS library and places it in execution.

2. The input file is the file which has been previously prepared and contains the input data for the program. The output file contains the reports generated by the program. The P-code refers to the type terminal on which the output reports are to be printed. Permissible P-codes and their meanings are as follows:

   1 - Teletypes, Terminets, TI Silent700's and others that do not have form-feeding capabilities and thereby must rely on the counting of lines to establish 11-inch pages.

   2 - DCT 500's, DECwriters, paging Terminets, Beta's and similar form-feeding, wide-carriage terminals.

   3 - Conventional line printers that require a numeric "1" in the first column for top-of-form.

3. If a production forecast (predictive run) is desired, a zero is entered in response to the program's question concerning the type of run.

4. For predictive runs the program will request a starting output date and the number of months between output lines. The starting date will normally be the first date on which output is desired. This date must be later than the date specified on line 700 of the input data form. The number of months between output lines enables the user to schedule production monthly, quarterly, etc. The maximum number of months allowed between output lines is 12.

5. When the calculations are complete the program will ask the question "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the run recomputed. The program will ask for:

   a) The line number of the input data line on which a change is wanted.

   b) The position of the data item on the line.

   c) The new data value to be inserted.

   Using this method, any number of data items can be changed. Three zeros are used to indicate that the OVER sequence should terminate and the new run should begin. In this example the user is changing the fourth value on line 701 to 1000 (reducing the input line pressure from its original value of 1500 psi to 1000 psi).

6. This indicates that the file containing the output report has been saved.

The second page of the report for each run made in Example 1 is shown on the opposite page. Notice that the first run reflects the projection for the well against a 1500 psi line pressure, while the second run illustrates the improvement expected due to a lower line pressure of 1000 psi (subject to a maximum well rate of 10,000 Mcf/D).

7. The first three lines printed in the upper left-hand corner contain the information input on lines 101-103.

8. The following items appear under the heading "Predicted Performance":

   a) Month-Day-Yr - The date for which the following items on the output line apply. The dates for output are governed either by the terminal response to the question asking for an output schedule or the dates on the 701-series lines.

   b) Flowing WHP, Psig - The flowing wellhead pressure. This pressure will either be the minimum specified wellhead pressure or a computed wellhead pressure, depending upon whether the well is producing at the maximum allowed rate.

   c) Flowing BHP, Psig - The flowing bottom-hole pressure at the producing depth.

   d) Avg. S.I. BHP, Psig - The average reservoir pressure at the specified date.

   e) Gas Rate, M/D - The average gas rate for the preceding output interval. Note that this value is not the well rate for the date printed at the left.

   f) Cum. Gas, BCF - Cumulative gas production.

   g) Cum. Rec., Pct. - Cumulative percent recovery of the initial gas-in-place.

   h) Z-Factor - The reservoir Z-factor at the average reservoir pressure and average reservoir temperature.

EXAMPLE NUMBER 1 (7)
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(8) PREDICTED PERFORMANCE

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1500.0	2657.6	2994.4	9774.	0.0098	0.10	0.9072
1- 1.000-80	1500.0	1907.4	2378.0	4986.	1.8296	19.59	0.8956
1- 1.000-81	1500.0	1791.2	2064.1	2716.	2.8237	30.23	0.8968
1- 1.000-82	1500.0	1754.5	1902.9	1431.	3.3462	35.83	0.8994
1- 1.000-83	1500.0	1744.5	1821.0	735.	3.6144	38.70	0.9013
1- 1.000-84	1500.0	1741.9	1780.1	366.	3.7480	40.13	0.9023
1- 1.000-85	1500.0	1741.2	1760.4	176.	3.8122	40.82	0.9027
1- 1.000-86	1500.0	1741.2	1751.5	79.	3.8411	41.13	0.9029
1- 1.000-87	1500.0	1740.9	1745.5	54.	3.8607	41.34	0.9031
1- 1.000-88	1500.0	1741.3	1743.5	17.	3.8670	41.40	0.9031
1- 1.000-89	1500.0	1741.0	1742.3	11.	3.8711	41.45	0.9031

Report Resulting from Original Data
(Page 2)

EXAMPLE NUMBER 1
GASWELL PREDICTION
WITH 701-799 LINES IN FILE

(6) PREDICTED PERFORMANCE

MONTH-DAY-YR	FLOWING WHP PSIG----	FLOWING BHP PSIG----	AVG. SI BHP PSIG----	GAS RATE M/D----	CUM. GAS BCF-----	CUM. REC. PCT---	Z FAC. ------
1- 1.000-79	1383.0	2645.1	2996.3	10000.	0.0100	0.11	0.9072
1- 1.000-80	1000.0	1553.0	2230.5	6265.	2.2968	24.59	0.8962
1- 1.000-81	1000.0	1319.1	1800.3	3784.	3.6818	39.42	0.9018
1- 1.000-82	1000.0	1218.5	1543.9	2309.	4.5246	48.44	0.9099
1- 1.000-83	1000.0	1179.0	1368.0	1401.	5.0361	53.92	0.9162
1- 1.000-84	1000.0	1163.9	1293.8	839.	5.3425	57.20	0.9202
1- 1.000-85	1000.0	1158.2	1237.9	495.	5.5237	59.14	0.9227
1- 1.000-86	1000.0	1156.4	1205.7	284.	5.6274	60.25	0.9241
1- 1.000-87	1000.0	1155.8	1184.4	188.	5.6962	60.99	0.9251
1- 1.000-88	1000.0	1155.1	1172.8	102.	5.7334	61.39	0.9256
1- 1.000-89	1000.0	1155.6	1165.7	63.	5.7563	61.63	0.9259

Report Resulting from Data as Modified
in Response to "WANT TO ALTER INPUT DATA--?"
(Page 2)

Example 2
Production Forecast - Interactive

This example illustrates use of the program in the predictive mode when the user desires to control the production constraints at the terminal while the program is executing. This mode of execution can be invoked by not including any of the 701-799 lines in the input data file. The program will then ask for the production constraints interactively.

1-3 Same as Example 1.

4. Same as Example 1. Here the user is requesting quarterly output.

5. Since no 701-799 lines have been included in the input data file the program asks the user for information that would normally be supplied on those lines. The program will then proceed to compute results until the date supplied as the first item has been reached.

6. When the interactive mode of execution is being used, a recap of the predicted performance is printed on the terminal until the last supplied time has been reached. This enables the user to monitor the progress of the calculations.

7. Three responses to the "MORE--?" question are valid: NO, OVER, and YES.

   NO - This response causes the run to terminate.

   OVER - This response allows the user to change his input data for a new run. The use of this response is exactly the same as illustrated in Example 1 where "YES" is answered to the question "WANT TO ALTER INPUT DATA--?".

   YES - This response indicates that the interactive run is to continue with a new set of production constraints.

8. Following an "OVER" or "YES" response, the program does not allow the user to change the output schedule. It proceeds directly to the question asking for a set of production constraints. Here the user is requesting another year of output with the same line pressure as before.

9. The predicted performance for the new run is printed.

10. The "NO" response to the "MORE--?" question terminates the calculations.

11. The program indicates the output file containing the complete report has been saved. The output file in this case will contain one report for both the original run and the subsequent run. The information will be exactly the same as the recaps shown on the dialogue page, but the output will be continuous, that is all nine lines of projections will appear under one set of headings.

```
RUN GASWELL
 GASWEL @ 10:53:00 ON  1/22/79 (1)


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX2 XX2OUT 2 (2)


 ENTER TYPE OF RUN:
  0 = PREDICTIVE
  1 = COMPARISON BASED ON WELLHEAD PRESS
  2 = COMPARISON BASED ON RATE ---?0 (3)


 ENTER OUTPUT STARTING DATE (MO,DAY,YR) AND
 OUTPUT TIME INTERVALS (MOS.) --?1 1 79 3 (4)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 80 1500 5000 0 100 (5)

                 FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR     WHP        BHP        SI BHP     RATE       GAS        REC.       Z FAC. (6)
------------     PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---     ------

 1- 1.000-79      2254.0     2825.6     2998.1     5000.      0.0050      0.05     0.9073
 4- 1.000-79      1741.3     2281.7     2832.2     5000.      0.4550      4.87     0.9007
 7- 1.000-79      1550.6     2087.1     2667.5     5000.      0.9100      9.74     0.8945
10- 1.000-79      1500.0     1983.2     2530.8     4721.      1.3444     14.39     0.8950
 1- 1.000-80      1500.0     1925.7     2412.3     4089.      1.7205     18.42     0.8955


 MORE --?YES (7)


 ENTER VALUES FOR NEXT SEQUENCE. VALUES REQUIRED ARE:
  MONTH,DAY,YR
  MIN. WHP
  MAX. RATE
  B/MM
  WELLHEAD TEMP. ---- ?1 1 81 1500 5000 0 100 (8)

                 FLOWING    FLOWING    AVG.       GAS        CUM.       CUM.
MONTH-DAY-YR     WHP        BHP        SI BHP     RATE       GAS        REC.       Z FAC. (9)
------------     PSIG----   PSIG----   PSIG----   M/D----    BCF-----   PCT---     ------

 4- 1.000-80      1500.0     1880.4     2310.9     3534.      2.0422     21.87     0.9959
 7- 1.000-80      1500.0     1845.4     2223.4     3046.      2.3194     24.83     0.8962
10- 1.000-80      1500.0     1818.2     2147.5     2613.      2.5597     27.41     0.8965
 1- 1.000-81      1500.0     1797.5     2082.7     2230.      2.7649     29.60     0.8967


 MORE --?NO (10)


FILE - XX2OUT    SAVED. (11)
READY.
```

Example 3
Comparison with Observed Data

This example illustrates use of the program to compare observed production history with computed results. This comparison will be on the basis of wellhead pressure.

As discussed previously, when comparisons are being performed the observed data should be entered in chronological sequence on the 701-799 lines on the input data form. For a comparison based on wellhead pressure the program will force the well to produce at the input rates and compute the corresponding wellhead pressures. The computed pressures will not be affected in any way by the input pressures. A report showing the comparison will then be produced.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on wellhead pressure.

4. When comparison runs are being performed, a table is printed on the terminal which shows the test times along with computed and observed values. In this example the observed and calculated rates are shown to be the same since only wellhead pressures are actually being computed. The observed pressure will be the test pressure which is tabulated along with the computed pressure.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated wellhead pressures are too low so the user increases the permeability (input as the first word on line 200) to one millidarcy in an attempt to get a better history match. The second table shows a good match on pressure so the run is terminated.

6. The program indicates that the file containing the output has been saved.

The second page of the output report will show the same information contained in the table that appears on the terminal during execution, but with the addition of three lines of heading information and a title, "PERFORMANCE COMPARISON". In this example, four pages of output would result; a first and second page for the original run, and a first and second page for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:51:00 ON  1/29/79


 INPUT FILE,OUTPUT FILE, & P-CODE --?XX3 XX3OUT 2 (2)


ENTER TYPE OF RUN:
 0 = PREDICTIVE
 1 = COMPARISON BASED ON WELLHEAD PRESS
 2 = COMPARISON BASED ON RATE ---?1 (3)

                OBSERVED  CALC.      OBSERVD  CALC.
MONTH-DAY-YR    WHP       WHP        RATE     RATE
------------    PSIG----  PSIG----   M/D----  M/D----

 1- 1.000-78     1500.0     1394.9     9540.    9540.
 2- 1.000-78     1500.0     1202.5     6590.    6590.
 3- 1.000-78     1500.0     1151.4     6160.    6160. (4)
 7- 1.000-78     1500.0     1180.4     5040.    5040.
 1- 1.000-79     1500.0     1259.1     3910.    3910.


WANT TO ALTER INPUT DATA --?YES (5)


LINE, WORD, VALUE --?200 1 1


LINE, WORD, VALUE --?0 0 0

                OBSERVED  CALC.      OBSERVD  CALC.
MONTH-DAY-YR    WHP       WHP        RATE     RATE
------------    PSIG      PSIG       M/D      M/D----

 1- 1.000-78     1500.0     1507.5     9540.    9540.
 2- 1.000-78     1500.0     1518.5     6590.    6590.
 3- 1.000-78     1500.0     1510.4     6160.    6160.
 7- 1.000-78     1500.0     1502.0     5040.    5040.
 1- 1.000-79     1500.0     1497.8     3910.    3910.


 WANT TO ALTER INPUT DATA --?NO


FILE - XX3OUT    SAVED. (6)
READY.
```

Example 4
Comparison with Observed Data

This example illustrates the use of the program when comparing computed rates to observed values. In this case the program is forced to produce at the wellhead pressures entered on the 701-799 lines. The corresponding computed rates can then be compared to the observed rates.

Comments with respect to the circled numbers shown in the dialogue are as follows:

1. Same as Example 1.

2. Same as Example 1.

3. The user indicates that the calculations are to be a comparison based on rate.

4. As with the comparison in the prior example, times along with observed and calculated values are tabulated at the user's terminal. In this case the observed and calculated pressures are identical, with the variance between the observed and computed rates being illustrated.

5. When the comparison is complete, the program will ask "WANT TO ALTER INPUT DATA--?" Two answers are valid. The response "NO" will terminate the run. The response "YES" will allow the user to change his input data and have the comparison recomputed. See Example No. 1.

   In this example the calculated rates are too high, so the user reduces the fracture length (input as the first word on line 210) to 400 feet. A good match on producing rates results so the run is terminated.

6. The program indicates that the file containing the output report has been saved. As in the previous example, the output will consist of four pages -- one two-page set for the original run and another two-page set for the altered run.

```
RUN GASWELL (1)
 GASWEL @ 10:41:00 ON  1/29/79


  INPUT FILE,OUTPUT FILE, & P-CODE --?XX4 XX4OUT 2 (2)


  ENTER TYPE OF RUN:
   0 = PREDICTIVE
   1 = COMPARISON BASED ON WELLHEAD PRESS
   2 = COMPARISON BASED ON RATE ---?2 (3)

                    OBSERVED   CALC.      OBSERVD   CALC.
  MONTH-DAY-YR      WHP        WHP        RATE      RATE
  ------------      PSIG----   PSIG----   M/D----   M/D----

   1- 1.000-78        1500.0     1500.0     9540.     9857.
   2- 1.000-78        1500.0     1500.0     6590.     6951. (4)
   3- 1.000-78        1500.0     1500.0     6160.     6495.
   7- 1.000-78        1500.0     1500.0     5040.     5172.
  1-10.000-79         1500.0     1500.0     3545.     3670.


  WANT TO ALTER INPUT DATA --?YES (5)


  LINE, WORD, VALUE --?210 1 400


  LINE, WORD, VALUE --?0 0 0

                    OBSERVED   CALC.      OBSERVD   CALC.
  MONTH-DAY-YR      WHP        WHP        RATE      RATE
  ------------      PSIG----   PSIG----   M/D----   M/D----

   1- 1.000-78        1500.0     1500.0     9540.     9547.
   2- 1.000-78        1500.0     1500.0     6590.     6585.
   3- 1.000-78        1500.0     1500.0     6160.     6162.
   7- 1.000-78        1500.0     1500.0     5040.     4935.
  1-10.000-79         1500.0     1500.0     3545.     3557.


  WANT TO ALTER INPUT DATA --?NO


  FILE - XX4OUT    SAVED. (6)
  READY.
```

TECHNICAL NOTES

1. The procedures used in GASWELL to compute dimensionless pressure versus dimensionless time are based upon the following work: Gringarten, A. C., Ramey, H. J., Jr., and Ravhavan, R.: "Unsteady-State Pressure Distributions Created by a Well with a Single Infinite-Conductivity Vertical Fracture", Soc. Pet. Eng. J. (Aug. 1974) 347-360; AIME Trans., Vol. 257.

2. The constant-rate solutions from Gringarten, et. al. are converted to variable-rate solutions needed by GASWELL using superposition.

3. The average reservoir pressure is computed by subsequent time periods by material balance.

4. The pressure drop in the wellbore is calculated using the technique of Cullender and Smith.

GASWELL Simulator
Input Data Form
2/79

RUN DESCRIPTION:

Well Name & No.	101	
Field & Zone	102	
County & State	103	

RESERVOIR AND WELL DATA:

	Permeability (Mds.)	Porosity (%)	Net Pay (Feet)	Liquid Saturation, %	Temperature of Zone, °F
200					
	Fracture[1] Length, Ft.	Drainage Area Length X, Ft.	Drainage Area Length Y, Ft.	Well Location[2] X, Ft.	Well Location[2] Y, Ft.
210					
	Flowstream O.D., Inches	Flowstream I.D., Inches	Zone Depth, (Feet)	Pipe Roughness (Inches)	Liquid Comp. (V/MMV/PSI)
220					
	Gas Gravity (Air=1)	Liquid Gravity (Water=1.0)	H_2S Diluent (Mol %)	CO_2 Diluent (Mol %)	N_2 Diluent (Mol %)
230					
	Non-Darcy Flow[3] Coef., D/MCF	Skin[4] Factor	Fracture[5] Type	Standard Pressure, PSIA	Standard Temp., °F
Optional 240					

TIME, PRESSURE & RATE DATA:

	Beginning Date[6] Mo. Day Year	Initial Reservoir, PSIG	Minimum[7] Rate MCF/D		
Required Line 700					
	Limiting Date[6] Mo. Day Year	Limiting Well-head Flow, PSIG	Limiting Gas Rate, MCF/D	Liquid Rate (BBL/MMCF)	Wellhead Temp, °F
701					
702					
703					
704					
705					

Use lines 701-799 to enter limiting time, wellhead pressure & rates. If omitted, program will ask for limiting conditions.

NOTES:

(1) If value less than 1 foot entered, it will be used as the wellbore radius with no fracture.

(2) Distance measured from lower left corner of rectangular drainage area.

(3) Used to handle turbulence.

(4) Dimensionless pressure drop due to skin effects.

(5) Enter zero for infinite conductivity fracture. Enter 1 for uniform flux fracture.

(6) Fractional day number may be entered; for example, "7 9.25 77" would be 6 hours(.25 days) into the ninth day of July 1977.

(7) Calculations will stop when the specified rate is reached.

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LARGE MAPS,
1-4 ARE TO
GO HERE.

SAN JUAN CO.
CASE # 7209
NM OIL CON. DIV.

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF KOCH INDUSTRIES, INC. FOR
DESIGNATION OF TIGHT FORMATION,
SAN JUAN COUNTY, NEW MEXICO.

Case 7209

APPLICATION

Comes now KOCH INDUSTRIES, INC., by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Mesaverde formation (Blanco Mesaverde Pool) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

1. Applicant is the owner and operator of certain interests in the Mesaverde formation (Blanco Mesaverde Pool) underlying the following described lands situated in San Juan County, New Mexico:

Township 32 North, Range 8 West, N.M.P.M.
Section 7: All
Section 18: All
Section 19: All
Section 30: All
Section 31: All

Township 32 North, Range 9 West, N.M.P.M.
Sections 10 through 15: All
Sections 22 through 27: All
Section 34: All
Section 35: All

Containing a total of 10,551.00 acres, more or less.

2. The Mesaverde formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Mesaverde formation is 4200 feet and the wells completed for production in said formation will be unable to produce any gas, against atmospheric pressure, without stimulation.

4. No well drilled into the Mesaverde formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Mesaverde formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

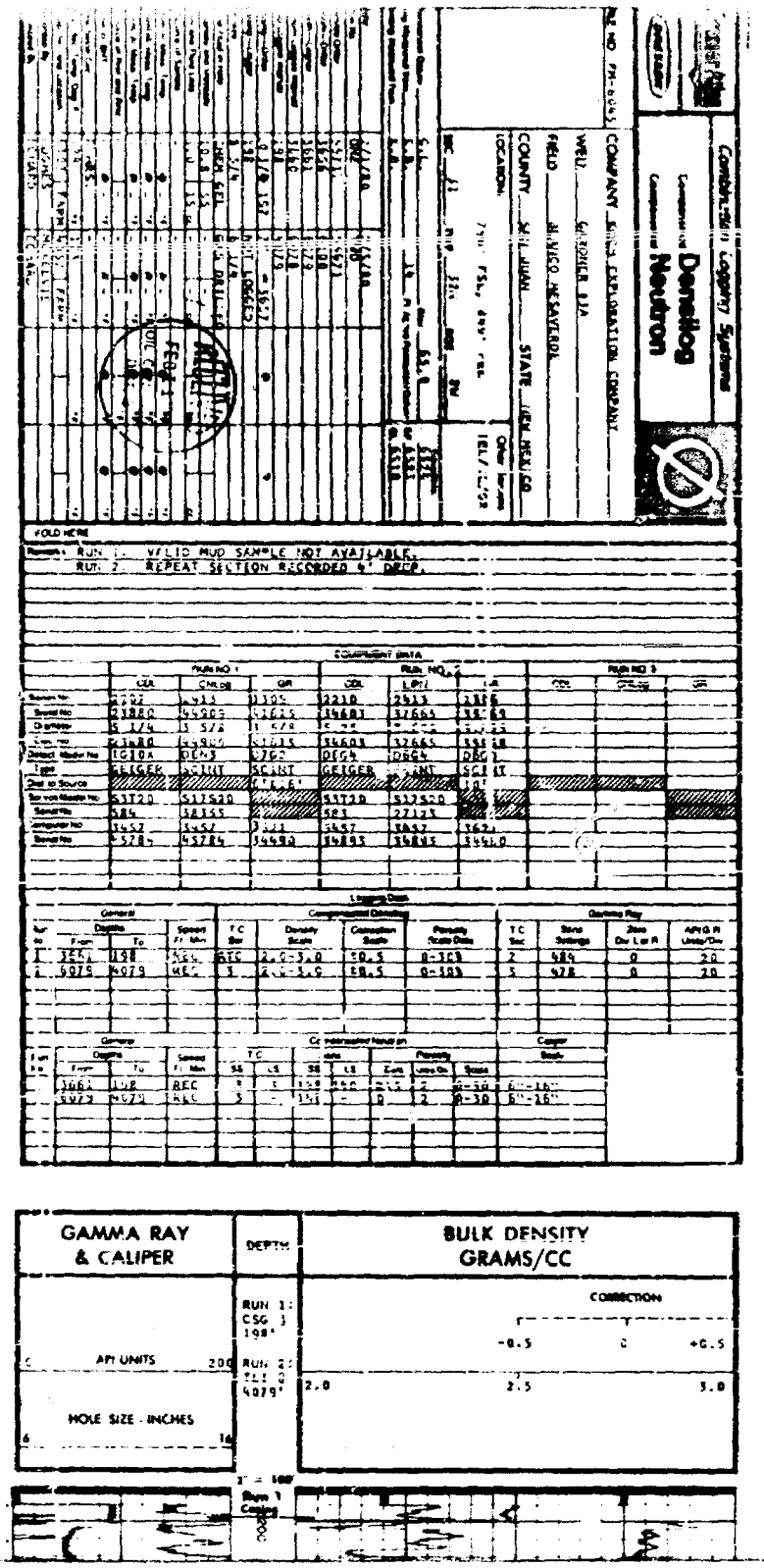
CAMPBELL, BYRD AND BLACK, P.A.

By _____
William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 9th day of March, 1981.

_____
William F. Carr


Compensated Neutron
COMPANY
WELL
FIELD
COUNTY
STATE
LOCATION
FOLD HERE
Remarks: RUN 1: VALID MUD SAMPLE NOT AVAILABLE.
RUN 2: REPEAT SECTION RECORDED 4" DEEP.
EQUIPMENT DATA
RUN NO. 1
RUN NO. 2
RUN NO. 3
Log Data
General
Compensated Neutron
Gamma Ray
Gamma
Compensated Neutron
Caliper
GAMMA RAY & CALIPER
DEPTH
BULK DENSITY GRAMS/CC
CORRECTION
API UNITS
HOLE SIZE - INCHES
RUN 1:
CSG. 1
198'
RUN 2:
4079'
-0.5
0
+0.5
2.0
2.5
3.0

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

September 1, 1981

Campbell, Byrd & Black, P.A.
P. O. Box 2208
Santa Fe, New Mexico 87501

Attention: William F. Carr, Esq.

Gentlemen:

Regarding Case No. 7209, the application of Koch Industries, Inc., for designation of a tight formation, which was heard by me on March 25, 1981, we feel that certain additional information is necessary in order to make a proper recommendation to the Federal Energy Regulatory Commission as to which lands covered by the application should be considered for recommendation and the criteria which should be used in analyzing the lands.

I have discussed this matter with Mr. David B. Friend, the consulting reservoir engineer who prepared and presented Koch's case, and have advised him that we will need the following:

1. Estimated recoverable Mesaverde reserves for the entire area of interest, (section by section), or at least for the lands in the lowermost two tiers of sections in the area, i.e., Sections 30 and 31, Township 32 North, Range 8 West, and Sections 25 through 27 and 34 through 36 of Township 32 North, Range 9 West. This could be submitted by a revised Exhibit No. 6.

2. A calculation of the economics involved in determining the necessity for the incentive price pursuant to the provisions of 18 CFR §271.703(c)(2)(B). These data should show the economics of producing an average well in the area to depletion, and show the rate of return which could be expected under normal Section 103 price for the gas as compared to the rate of return which could be expected under the incentive price. Both of these rates of return should be compared to a reasonable

rate of return which Koch finds is necessary to justify additional drilling in the area. These data could be submitted in the form of a revised Exhibit No. 13.

Upon receipt of the above information, we will be happy to continue our analysis of the evidence in Case No. 7209, and would hope to be able to make a recommendation to the FERC soon.

Very truly yours,

DANIEL S. NUTTER
Chief Engineer and
Trial Examiner, Case No. 7209

DSN/dr

CASE 7209: Application of Koch Industries, Inc. for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Mesaverde formation underlying portions of Township 32 North, Ranges 8 and 9 West, containing 10,551 acres, more or less, as a tight formation pursuant to Section 107 of the Natural Gas Policy Act and 18 CFR Section 271.701-705.

CASE 7181: (Readvertised)

Application of Read & Stevens, Inc. for a unit agreement, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks approval for the Hernandez Draw Unit Area, comprising 2,560 acres, more or less, of Federal, State, and Fee lands in Townships 4 and 5 South, Ranges 26 and 27 East.

CASE 7197: (Readvertised)

In the matter of the hearing called by the Oil Conservation Division on its own motion for an order extending certain pools in Chaves County, New Mexico:

(g) EXTEND the Bull's Eye-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 8 SOUTH, RANGE 28 EAST, NMPM
Section 1: SE/4 SW/4

(i) EXTEND the Chaveroo-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 8 SOUTH, RANGE 32 EAST, NMPM
Section 10: NE/4

(l) EXTEND the Diablo-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 10 SOUTH, RANGE 27 EAST, NMPM
Section 22: W/2 SW/4 and SW/4 NW/4
Section 27: NW/4 NW/4

(m) EXTEND the Diamond Mound-Atoka Gas Pool in Eddy and Chaves Counties, New Mexico, to include therein:

TOWNSHIP 15 SOUTH, RANGE 27 EAST, NMPM
Section 34: S/2

TOWNSHIP 16 SOUTH, RANGE 27 EAST, NMPM
Section 15: N/2
Section 16: N/2

(r) EXTEND the L.E. Ranch-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 10 SOUTH, RANGE 28 EAST, NMPM
Section 29: S/2 NW/4
Section 30: S/2 NE/4

(s) EXTEND the Linda-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 6 SOUTH, RANGE 26 EAST, NMPM
Section 30: NW/4 SE/4 and SW/4 NE/4

(y) EXTEND the Railroad Mountain-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 7 SOUTH, RANGE 28 EAST, NMPM
Section 35: SW/4 SW/4

TOWNSHIP 8 SOUTH, RANGE 28 EAST, NMPM
Section 2: W/2 NW/4

(z) EXTEND the East Siete-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 8 SOUTH, RANGE 31 EAST, NMPM
Section 10: SE/4
Section 11: SW/4

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
WILLIAM G. WARDIE

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SANTA FE, NEW MEXICO 87501
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

March 9, 1981

Case 7209

Mr. Joe D. Ramey
Director
Oil Conservation Division
New Mexico Department of
Energy and Minerals
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: Application of Koch Industries, Inc. for Designation of Tight Formation, San Juan County, New Mexico

Dear Mr. Ramey:

Enclosed in triplicate is the application of Koch Industries, Inc. in the above-referenced matter.

The applicant requests that this matter be included on the docket for the examiner hearing scheduled to be held on March 25, 1981.

Very truly yours,

William F. Carr

William F. Carr

WFC:lr

Enclosures

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF KOCH INDUSTRIES, INC. FOR
DESIGNATION OF TIGHT FORMATION,
SAN JUAN COUNTY, NEW MEXICO.

Case 7209

APPLICATION

Comes now KOCH INDUSTRIES, INC., by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Mesaverde formation (Blanco Mesaverde Pool) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

1. Applicant is the owner and operator of certain interests in the Mesaverde formation (Blanco Mesaverde Pool) underlying the following described lands situated in San Juan County, New Mexico:

Township 32 North, Range 8 West, N.M.P.M.
Section 7: All
Section 18: All
Section 19: All
Section 30: All
Section 31: All

Township 32 North, Range 9 West, N.M.P.M.
Sections 10 through 15: All
Sections 22 through 27: All
Section 34: All
Section 35: All

Containing a total of 10,551.00 acres, more or less.

2. The Mesaverde formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Mesaverde formation is 4200 feet and the wells completed for production in said formation will be unable to produce any gas, against atmospheric pressure, without stimulation.

4. No well drilled into the Mesaverde formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Mesaverde formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD AND BLACK, P.A.

By William F. Carr

William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 9th day of March, 1981.

William F. Carr
William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF KOCH INDUSTRIES, INC. FOR
DESIGNATION OF TIGHT FORMATION,
SAN JUAN COUNTY, NEW MEXICO.

Case 7209

APPLICATION

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1. Applicant is the owner and operator of certain interests in the Mesaverde formation (Blanco Mesaverde Pool) underlying the following described lands situated in San Juan County, New Mexico:

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Section 7: All
Section 18: All
Section 19: All
Section 30: All
Section 31: All

Township 32 North, Range 9 West, N.M.P.M.
Sections 10 through 15: All
Sections 22 through 27: All
Section 34: All
Section 35: All

Containing a total of 10,551.00 acres, more or less.

2. The Mesaverde formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Mesaverde formation is 4200 feet and the wells completed for production in said formation will be unable to produce any gas, against atmospheric pressure, without stimulation.

4. No well drilled into the Mesaverde formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Mesaverde formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD AND BLACK, P.A.

By _____
William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 9th day of March, 1981.

_____
William F. Carr

HERBIE
DAN

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7209
Order No. R- 6888

APPLICATION OF KOCH INDUSTRIES, INC.
FOR DESIGNATION OF A TIGHT FORMATION,
SAN JUAN COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on March 25, 1981, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this _____ day of January, 1982, the Division Director, having considered the testimony, the record, and the

recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Koch Industries, Inc., pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, requested the designation as a "tight formation" of the Mesaverde formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM

Section 7: All

Sections 18 and 19: All

Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM

Sections 10 through 15: All

Sections 22 through 27: All

Sections 34 and 35: All

containing a total of 10,551.0 acres, more or less.

(3) That the vertical limits of the Blanco-Mesaverde Pool in the area under consideration extend from the Huerfanito Bentonite in the Lewis Shale to a point 500 feet below the top of the Mesaverde formation of the Point Lookout member, and consist of the Cliffhouse, Menefee, and Point Lookout members, with the Cliffhouse and Point Lookout zones contributing most of the gas, and the less continuous Menefee sands also contributing in some wells.

(4) That in the area under consideration, the thickness and porosity of the three zones is as follows: Cliffhouse, average thickness about 50 feet, porosity range from four to 15 percent; Menefee, thickness range from 230 feet to 290 feet, porosity range from less than three percent to 17 percent; and Point Lookout, thickness range from 150 feet to 200 feet, porosity range from three percent to 14 percent. The average porosity for all sands in all three members is approximately eight percent.

(5) That the aforesaid three members of the Mesaverde group exhibit depositional characteristics of three distinct phases -- shoreline deposits during the regression of the Mancos Sea, non-marine deposits of coals, silts, and shales, and shoreline deposits during transgression of the Lewis Sea -- and overall combine to form a low permeability pay near the northern productive limits of the Blanco Mesaverde Pool.

(6) That the average depth from the surface to the top of the Cliffhouse formation of the Mesaverde group in the area

under consideration is approximately 5463 feet.

(7) That there have been 14 Mesaverde wells drilled in the area under consideration; that the expected ultimate recovery from these wells ranges from two million cubic feet of gas to 787 million cubic feet, and averages 374 million cubic feet.

(8) That development in the area to date consists of two sub-areas, with five of the 14 wells drilled to date being in the northern portion of the overall area, and nine of the 14 wells drilled to date being in the southern portion of the overall area.

(9) That the expected ultimate recovery for the five wells in the northern sub-area ranges from two million cubic feet of gas to 787 million cubic feet and averages 254 million cubic feet, while the expected ultimate recovery from the nine wells in the southern sub-area ranges from two million cubic feet of gas to 596 million cubic feet and averages 440 million cubic feet.

(10) That data are not available in this case to determine the in situ gas permeability of the Mesaverde formation in the northern sub-area under consideration in this case.

(11) That the data available to determine the in situ gas permeability in the southern sub-area in this case is sketchy, based upon applicant's Exhibits 9 and 10. That Exhibit 9

indicates an *in situ* permeability in applicant's Gardner Well No. 1, located in Unit M of Section 35, Township 32 North, Range 9 West, NMPM of 0.0208 md.

(12) That while Exhibit 10 purports to show an *in situ* permeability for applicant's Gardner Well No. 3, located in Unit N of Section 31, Township 32 North, Range 8 West, NMPM, equivalent to 0.0012 or 0.0013 md, it is believed that the permeability calculations discussed in Finding No. (11) are based on more accurate input data and assumptions, and more nearly reflect the true *in situ* permeability of the Mesaverde formation in the southern sub-area, and although Exhibit No. 10 should be disregarded, it is reasonable to assume that the *in situ* permeability of the Mesaverde formation in the southern sub-area is less than 0.1 md.

(13) That no pre-stimulation stabilized flow rates are available for any of the 14 wells drilled in the area under consideration, but that data indicating the capability of the formation to produce, without stimulation, is available for wells drilled in the southern sub-area as follows:

A. A non-stabilized flow rate of 47 MCF per day against atmospheric pressure was obtained on the Gardner Well No. 1 when it was drilled in 1954. A stabilized rate of production would have been less than 47 MCF per day.

B. Gardner Wells Nos. 2, 3, 3-A, 4, 4-A, and 5 were drilled with gas so that a continuous check was possible as to whether the formation was producing during drilling operations. Gardner Wells Nos. 2, 3, 3-A, 4-A, and one zone of 5 indicated "no gas while drilling." Gardner Well No. 4 indicated "slight show of gas while drilling," and one zone of Well No. 5 indicated that gas "too small to measure" was produced during drilling operations.

(14) That based upon the evidence discussed in Finding No. (13) above, it may reasonably be assumed that the stabilized productivity, prior to stimulation, of the wells completed in the Mesaverde formation in the southern sub-area is less than the 163 MCF per day which is the maximum productivity set forth in 18 C.F.R. 271.703(c)(2)(i)(B) for wells in the 5000-5500 foot range.

(15) That no data is available in this case to demonstrate the before-stimulation productivity of wells in the northern sub-area under consideration.

(16) That none of the wells drilled in the area is capable of producing, with or without stimulation, more than five barrels of oil per day.

(17) That there are fresh water aquifers in the area under consideration extending from the surface to the base of the Ojo

Alamo formation, which is found at an average depth of approximately 2185 feet; that an average of some 3278 feet of vertical distance separates the base of said Ojo Alamo and the top of the Cliffhouse member of the Mesaverde formation.

(18) That the state and federal regulations governing casing and cementing of wellbores, as well as the aforementioned vertical distances, should prevent any adverse impact upon the fresh water aquifers during both hydraulic fracturing and waste disposal operations.

(19) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(20) That the Division, by its Order No. R-1670-T dated November 14, 1974, approved infill drilling in the Blanco Mesaverde Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Mesaverde formation underlying the lands described in Finding No. (2) above and under consideration in this case.

(21) That it appearing to the examiner at the hearing of this case on March 25, 1981, that there was insufficient evidence to make the determination described in Finding No. (19) above, i.e., that the formation could or could not be developed economically absent the tight formation incentive price, the applicant was asked to submit additional evidence regarding well development and operating costs, reserves, and rates of return on investment under normal Section 103 gas prices and under Section 107 gas prices.

(22) That the requested data was submitted in the form of Revised Exhibits 6 and 13 in this case, and the original Exhibits 6 and 13 should be disregarded.

(23) That the data submitted by applicant on Revised Exhibit 13 in this case relates to reserves, development and operating costs, and rates of return in the southern sub-area only, and no data are available pertaining to such matters for wells drilled in the northern sub-area.

(24) That according to Revised Exhibit 13, the average ultimate recovery which may be expected under the Section 103 gas price in Sections 25, 26, 27, and 35, Township 32 North, Range 9 West, NMPM, and Section 31, Township 32 North, Range 8 West, NMPM, is approximately 494 million cubic feet of gas; that with development costs of approximately $400,700 per well and operating costs of approximately $4800 per year per well, the gross revenue received less expense interest and royalty

interest and severance and ad valorem taxes, the operator may expect an 8.8 percent rate of return before income taxes on his investment, or 7.3 percent rate of return after income taxes.

(25) That according to Revised Exhibit 13, the average ultimate recovery which may be expected in the same area and under the same conditions as described in Finding No. (24) above, except under the Section 107 incentive gas price, is some 516 million cubic feet of gas, and the operator may expect a 39.2 percent rate of return on his investment before income taxes, or 27.5 percent rate of return after income taxes.

(26) That while the 39.2 percent rate of return before taxes or 27.5 percent rate of return after taxes provided by the incentive price may seem excessive, ~~under the incentive price,~~ it is obvious that the 8.8 percent rate of return before taxes or 7.3 percent rate of return after taxes under the Section 103 price is too low to justify the risk of drilling additional wells in the area.

(27) That inasmuch as there is no data as to pre-stimulation flow rates in the northern sub-area, nor is there any data relating to development and operating costs vs. revenues, and rates of return, no recommendation as to designation of tight formation should be made at this time for that area.

(28) That the data that is available in this case justifies the recommendation as a tight formation in the

southern sub-area, and that area should be described as follows:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM

Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM

Sections 25 through 27: All

Sections 34 and 35: All

containing a total of 4216.98 acres, more or less.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Mesaverde producing interval extending from the Huerfanito Bentonite in the Lewis shale to a point 500 feet below the top of the Point Lookout member of the Mesaverde group, and consisting of the Cliffhouse, Menefee, and Point Lookout members of the Mesaverde group, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 32 NORTH, RANGE 8 WEST, NMPM

Sections 30 and 31: All

TOWNSHIP 32 NORTH, RANGE 9 WEST, NMPM

Sections 25 through 27: All

Sections 34 and 35: All

containing a total of some 4216.98 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (2) of this order but not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO

OIL CONSERVATION DIVISION

JOE D. RAMEY,

Director

S E A L

Memo

From

FLORENE DAVIDSON
ADMINISTRATIVE SECRETARY

To Called in by Bill Carr
3/5/81

Koch Industries Inc.

Designation of Tight Formation
San Juan County
mesaverde formation

T 32 N, R 8 + 9 W

10,551 acres

OIL CONSERVATION COMMISSION-SANTA FE