CASE 7300: DOME PETROLEUM CORPORATION
FOR DESIGNATION OF A TIGHT FORMATION,
SANDOVAL COUNTY, NEW MEXICO

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for
October 21

Case No. 7300

Application

Transcripts

Small Exhibits

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico. CASE 7300

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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I N D E X

STATEMENT BY MR. BATEMAN 4

MICHAEL FUCHS

Direct Examination by Mr. Bateman 5

Cross Examination by Mr. Stamets 12

KEVIN TRACY

Direct Examination by Mr. Bateman 13

Questions by Mr. Chavez of Mr. Fuchs and Mr. Tracy 21

Cross Examination by Mr. Stamets 22

Statement by Mr. Cole 31

Questions by Mr. Chavez 32

Recross Examination by Mr. Stamets 34

E X H I B I T S

Applicant Exhibit One, Map	6
Applicant Exhibit Two, Structure Map	6
Applicant Exhibit Three, Summary	7
Applicant Exhibit Four, Cross Sections	9
Applicant Exhibit Five, Log	11
Applicant Exhibit Six, Summary	14
Applicant Exhibit Seven, List of wells	15
Applicant Exhibit Eight, Pressure Data	15
Applicant Exhibit Nine, Pressure Data	15
Applicant Exhibit Ten, Pressure Data	15
Applicant Exhibit Eleven, Tabulation	17
Applicant Exhibit Twelve, Sketch	19

MR. STAMETS: We'll call next Case 7300.

MR. PEARCE: Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

MR. BATEMAN: Mr. Examiner, I'm Ken Bateman, with White, Koch, Kelly, and McCarthy, appearing on behalf of Dome Petroleum Corporation, the applicant.

I have two witnesses.

MR. STAMETS: Any other appearances in this case?

(Witnesses sworn.)

MR. BATEMAN: Mr. Examiner, before we begin, I have given you a copy of the documented evidence we intend to introduce. Some of the exhibits, specifically Exhibit Two, I believe, and Four A and B, are reduced and I have larger copies here, which I will refer to.

MR. STAMETS: Do you happen to have one extra set of exhibits --

MR. BATEMAN: Yes, sure.

MR. STAMETS: -- for Mr. Chavez there? Thank you.

MR. CHAVEZ: Thank you.

MR. BATEMAN: Also Exhibit Five, which is a type log.

MICHAEL FUCHS

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you state your full name, please, and place of employment for the record?

A. Michael Fuchs. I'm employed as an exploration geologist at Dome Petroleum Corp.

Q. Have you previously testified before the Commission?

A. No.

Q. Would you give a resume, then, of your educational background and your work experience in the petroleum industry?

A. I have a Bachelor's from the University of Denver in geography, minor in geology and anthropology. Subsequently spent three years with Colorado School of Mines; fulfilled the requirements for a Bachelor of Science in geological engineering; applied for the Masters program in

geological engineering and completed one year of course work.

Q. And have you been employed as a geologist then in the petroleum industry?

A. Yes. I spent six months after that at Trend Exploration as an exploration geologist and two -- I've spent my last two years with Dome Petroleum as an exploration geologist.

Q. In your employment with Dome Petroleum have you become familiar with the application which is being heard today, as well as the area in question?

A. Yes, I have.

Q. Have you actively worked in that area?

A. Yes, I have.

MR. BATEMAN: Mr. Examiner, are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q. Would you refer, please, to what's been marked as Exhibit One and Two and state what Dome seeks by its application today?

A. Well, Exhibit One is an index map showing the relative location of the Rusty Chacra area. It's approximately six miles south of the town of Counselor in Sandoval County, New Mexico. It includes all or portions of Townships 22 North, 6 West and 7 West, and 21 North, 5 West,

6 West, and 7 West.

I'd like to enter into the record that there's a mistake on this index map, and that the exact boundary of the proposed tight gas area is shown on Exhibit Two, if you would turn to it.

Exhibit Two is a structure contour map on top of the Chacra producing zone. It's done on a contour interval of 50 feet. It shows monoclinal dip down into the basin to the northeast.

It also shows all wells in the area and cross sections lines A-A' and B-B'.

Q. The wells shown on the exhibit tested the Chacra in each case?

A. Yes. Yes, they do.

Q. Okay.

A. Okay. If you would turn to Exhibit Three, this is a summary of the geology. Gas production in the area is from build-up of transitional shaly sands and siltstones, which are interpreted to be of a pro-delta low energy origin.

Sandstones are gray to light gray, fine grained, silty, shaley, and slightly to moderately calcitic.

The fine graned and clay filled nature

of the sands results in low porosity and permeability and commercial production, when obtained, is only achieved through extensive fracturing and treatment of the formation.

Structural dip is to the northeast at about 100 feet per mile and is of little consequence since this is a stratigraphic trap. The productive zone, which is most commonly been called the Chacra or the La Ventana, is a time stratigraphic equivalent of the upper unnamed tongue of the Cliffhouse transitional sandstone. This nomenclature is derived from correlating to sections done by James E. Facet, a paper that he gave on Cliffhouse sandstone in 1977, New Mexico Geologic Society Guidebook No. 3.

In New Mexico Order No. 5459 the Chacra producing interval is defined as the interval in the Lewis shale extending from the Huerfanito bentonite bed to about 750 feet below the bed.

In our designated proposed area the top of the Chacra producing zone is about 110 feet below the Huerfanito bentonite. The producing zone is approximately 300 feet thick and about 200 feet below this -- this zone are some lower sands which have not been tested in any of the wells and for which we are not applying for tight gas status.

So just to clarify, this request for gas tight sand designation is for the uppermost sands below the

Huerfanito bentonite.

At this point I would also like to explain that the basis for the boundaries of the proposed tight gas sand area are based on both stratigraphic data and production data.

If you will turn back to Exhibit Two for reference, the southwest boundary is a stratigraphic boundary, in which the sands and silts, sands and silts show up. This can be seen on Section B-B', the gamma ray and porosity curves on B-B' show this quite well when you look at them in detail.

To the northeast there is a distinct gas/water contact which runs along the approximate area boundary. This contact was established by examination of the resistivity curves of the wells in the area and is borne out by production testing the area. The wells completed in or close to the edge were wet and/or produced a lot of water and little gas.

To the northwest and southeast the wells tighten up completely and there is again a stratigraphic boundary where the sands and siltstones shale out.

If you'll turn to Exhibits Four-A and Four-B, they are the cross sections, these sections show gamma ray and porosity curves. They also show perforations

and treatments and resulting IP's in the wells that produced or were completed in the Chacra.

An in depth study of all wells in the area showed minimum productive parameters of 10 ohms and 10 percent resistivity. Anything less than that did not appear to give up gas.

Looking at Section B-B', which is Exhibit Four-B, the first well on the section, the Filon Navajo Allotted 26 No. 1, you can -- looking across to the next well on the section, you can see that the Filon well tightens up. Since this is such a shaley zone to start with, this tightening up is only seen after detailed looking and counting of the sands, and looking at the gamma ray and porosity curves.

On this section you will also notice the Sun Oil El Paso Federal No. 1 has plenty of porosity but the resistivity was below 10 ohms throughout and completion testing in other wells indicates that this would have been wet.

Section A-A', which runs down the length of the area, actually does not go out of the area but in -- once again, in studying all the logs in the area the wells outside of the area do not meet the 10 ohms, 10 percent resistivity cutoff that were established. This is a -- you would count the net sand that it's a general sort of a thing,

you would get a few small streaks, stringers, greater than that, but if you compare -- if you look at Section A-A', which basically runs through the meat of the thing, you can see the zones, particularly the ones that we perforated, had porosities greater than 10 percent. This was not true of wells outside of the area.

Going to Exhibit Number Five, which is the type log, this simply shows the shaliness of the zone and low porosities, and that's about all that that's to show.

Q. Mr. Fuchs, is there any significant difference in the sand as reflected in these logs across the area in question?

A. There's not much difference at all, no, until you get out of the area and then in a detailed count of net sand, based on porosity and resistivity cutoffs, the thing does appear to tighten up.

Q. In your opinion are the logs of the wells as represented here representative of all the productive Chacra wells in the area in question?

A. Yes, they are.

Q. In your opinion, then, is this area recommended, then, for tight formation designation?

A. Yes, it is.

Q. Were Exhibits One through Five prepared

by you or under your direction?

A. Yes, they were.

MR. BATEMAN: Mr. Examiner, I offer at this time Exhibits One through Five.

MR. STAMETS: These exhibits will be admitted.

MR. BATEMAN: I have no further direct, at this point.

MR. STAMETS: Are there questions of this witness?

CROSS EXAMINATION

BY MR. STAMETS:

Q. Okay, the only question I can think of right now concerns Exhibit Five.

You have the top of the Chacra zone marked there. Is the base of the zone represented on this exhibit?

A. Yes, it is. Well, the base of what we're calling the possible productive zone is, and I would say it's at around 2260. If you look, it's shaled up completely and the Chacra zone, as I stated in here, as defined by New Mexico, is an interval 750 feet below the Huerfanito bentonite. The interval we're interested in, the interval

that is productive here, starts at approximately 100 feet below the Huerfanito bentonite marker, then, and goes for approximately 250 feet.

Q. Okay.

MR. STAMETS: Well, I'll have to reserve any additional questions until we hear the next witness.

MR. BATEMAN: Fine. All right. Call my next witness, please.

KEVIN TRACY

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you state your full name and place of employment for the record, please?

A. Kevin Tracy. I'm Senior Reservoir Engineer for Dome Petroleum.

Q. Have you previously testified before the Commission?

A. No, I haven't.

Q. Would you state, then, for the record your educational experience?

A. I received a Bachelor's and a Master's in engineering from Rice University. I had five years experience with Shell Oil Company as a reservoir engineer and for the past year have been employed by Dome Petroleum as a Senior Reservoir Engineer.

Q. In your employment with Dome Petroleum Corporation have you become familiar with the -- today's application or with the area in question?

A. Yes, I have.

Q. Do you have direct responsibility for it?

A. Yes, I have.

MR. BATEMAN: Mr. Examiner, are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q. Mr. Tracy, would you refer to what you've marked, or what I've marked as Exhibit Six and review the data which is indicated there?

A. Exhibit Six is a summary of the reservoir data for the application area for the Chacra formation, and of particular importance here is the average permeability of .07 millidarcies; unstimulated flow rate, too small to measure and average flow rate after fracture stimulation of 594 Mcf. Also the crude oil production is none in the area.

Q. All right, would you proceed, then, with

Exhibits Seven through Ten and state how the averages were obtained?

A. Okay. Exhibit Seven is a list of wells within the application area that have tested the Chacra formation. This exhibit shows the well name, operator, location, spud date, the depth to the top of the Chacra, any completion interval, and average production rate after fracture stimulation and a 3-hour potential test.

It also shows the well status for each of the wells.

We've asterisked the wells that would qualify for the 107 incentive pricing by spud date next to the spud date column.

Okay, on the previous exhibit the depth to the top of the Chacra came from an average of the data shown in Exhibit Seven; also, the after stimulation rate was the average of these numbers shown here.

Q. For the record, would you tell the Examiner whether there's a market for the gas now available from this area?

A. At the present time there's approximately fourteen wells producing. The remainder of all these wells are shut in, waiting on a gathering system. We have a gas contract for our wells in the area but no hookups yet.

Q. What kind of stimulation procedures have been followed generally in this area?

A. The standard completion practice is to perforate the well, immediately acidize, and follow with a fracture stimulation treatment.

Q. Has that been done then in all cases?

A. Every one of these wells has been fracture stimulated with jobs of varying sizes and varying types.

Q. All right, then, would you proceed then with Exhibits Eight, Nine, and Ten?

A. Exhibits Eight, Nine, and Ten illustrate pressure build-up data obtained for three wells within our application area.

I might start at Exhibit Eight, 8-A shows the Horner plot for the Chase Rusty Federal No. 4, and from Exhibit 8-A and 8-B we're able to determine what part of the data represents the Horner straight line and are able to calculate in situ gas permeability for this well at .13 millidarcies.

Exhibit Nine A and Nine B show the same type of information obtained for the Dome Navajo 20-22-7 No. 1, in which an in situ permeability to gas of .047 millidarcies was obtained.

Similarly, Exhibit Ten A and Ten B show

the Horner plot and calculation of permeability of .03 millidarcies for the Dome Federal 19-22-6 No. 1.

Q. Mr. Tracy, do you believe that these wells are -- as shown on Exhibits Eight, Nine, and Ten, are representative of the wells in the area included in the application?

A. Yes, I do. These three wells are located in the center of the application area and, if anything, they represent the better part of the reservoir.

Q. Is a Horner plot a standard in the industry?

A. Yes, it is.

Q. All right. Would you proceed, then, with Exhibit Number Eleven?

A. If I can back up just once, the permeability numbers shown on these Horner plots is where the .07 millidarcy average for the area was obtained by averaging those three wells.

Exhibit Eleven shows the nine wells within our application area that we're sure had fair tests of an unstimulated flow rate. By a fair test I mean that the well was swabbed down after perforating or after acidizing. The standard practice on all the other wells was to fracture stimulate them immediately after perforating. By swabbing

them down it removed any fluid column that might be holding back any gas production.

As you can see here, the -- the rates of these nine wells average too small to measure and only one case was there a measurable flow rate prior to fracture stimulation.

For comparison we show the 3-hour potential test after the farcture treatments for the same wells.

Q. How does the flow rate for the one well that did produce compare to the limit in the regulations?

A. It's below the guideline for this depth. The guideline at this depth is 59 Mcf per day against atmospheric pressure and certainly an average of these is a rate too small to measure.

Q. So your conclusion is, I take it then, the average unstimulated flow rate is too small to measure?

A. Yes.

Q. And that you found no crude oil production?

A. That's correct. There's no crude oil production at all in this area.

Q. Are you familiar with the fresh water aquifers in the area?

A. Not directly. I've been told that the

Ojo Alamo and Pictured Cliffs might be -- might be fresh water aquifers in addition to the Fruitland.

(Thereupon conversation was had off the record.)

Q. Mr. Tracy, your conclusion is that Ojo Alamo is the fresh water aquifer in the area.

Would you proceed with Exhibit Number Twelve and tell the Examiner how the fresh water aquifers will be protected?

A. Exhibit Twelve illustrates a typical casing design for the Chacra wells in this area and of particular significance is the surface casing and production casing are both cemented to surface with generally cement return durng the cementing operations and that would certainly protect any fresh water aquifers from -- from communication of other zones.

Q. Mr. Tracy, would you briefly state your opinion regarding the economics of the production of gas in this area?

A. The Chacra formation is so tight and not -- not a very prolific producer by any means, and for development to continue the 107 incentive pricing would really be required.

Q. In your opinion --

A. In my opinion.

Q. In your opinion, then, would the grant of this application prevent waste and protect correlative rights?

A. It would.

Q. Have you been in contact with other operators in the area?

A. Yes, I have. Received letters of support from several operators that I have talked to.

Q. All right, would you state for the record what you've received?

A. I have in hand a letter from Chase Development Company supporting our application; Benson Mineral Group; Jack A. Cole; Trend Exploration, Limited; Northwest Exploration Company; and have also talked to Elf Aquatain (sic); and Buckhorn, which also have working interest within our application area.

Q. Have they indicated any opposition to your application?

A. No, they indicated they were in full support of our application.

Q. Were Exhibits One -- or excuse me, Six through Twelve prepared by you or under your direction?

A. Yes, they were.

MR. BATEMAN: Mr. Examiner, I offer Exhibits Six through Twelve, and have no further direct, at this time.

MR. STAMETS: These exhibits will be admitted.

Are there some questions of this witness?

MR. CHAVEZ: Yes.

MR. STAMETS: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ OF MR. TRACY AND MR. FUCHS:

Q. In Township 21 North, 5 West, are the dry holes indicated on your Exhibit Two Chacra attempts?

MR. FUCHS: No, they were Gallup tests.

MR. TRACY: Exhibit Two was prepared by Mr. Fuchs.

MR. CHAVEZ: I'm sorry, I went too far, then.

MR. STAMETS: Well, I think as long as our reporter doesn't have any trouble with that, whoever the appropriate witness is should answer this question.

And I'd like a little clarification on that, then, while we're at that point.

MR. CHAVEZ: All right.

MR. STAMETS: If you don't mind.

CROSS EXAMINATION

BY MR. STAMETS:

Q. In 22 North, 7 West, there are symbols which indicate oil wells. Are those oil wells or something else?

A. (By Mr. Tracy) Those are oil and gas producers as well as oil wells in some cases. We have drilled four wells in there in the last year, partners with Tesoro. They're Tesoro wells. They're all Gallup wells. The sand is very poorly developed sand at best, and in two of them we had low GOR wells. We got about 60 barrels a day, 40 Mcf, out of two of them. They were pretty much identical.

Out of the second two, they were high GOR wells, and I think we -- they IP'd for about 20 barrels of oil a day, averaging, and about 400 Mcf.

So those are Gallup tests, Gallup producers.

Q. Does the large copy of this indicate which wells are Chacra wells and which wells are something else?

A. No, they don't.

Q. Good, that will give you something to do subsequent to the hearing, then, is to submit copies of this exhibit which clearly show which wells are Chacra wells

and which wells have tested the Chacra formation, and then identify those wells producing from some other horizon.

A. Okay. I could state for sure right now for the record, though, that the black dots are Gallup producers.

Q. Okay, fine.

A. They've already been filled in, and all the open circles are -- or the open gas signs are Chacra producers.

MR. STAMETS: Frank, do you have some more questions?

MR. CHAVEZ: Yes.

QUESTIONS BY MR. CHAVEZ CONTINUED:

Q. In your testimony you stated that you were not interested in including any area that might be productive, say, below this 310 feet interval that you've designated on Exhibit Five as the zone of interest for this application today.

A. That is correct.

Q. Okay. Then you want -- for the purposes of the order, then, you want the order to state that -- oh, boy, how do you word it -- that the Chacra zone for the purposes of the order would be from say the top of the Chacra

down 310, 20 feet, something like that?

A. Yes, that's fine. The reason I made that clarification in the first place is because this Chacra zone climbs throughout the section and not over our area, the area which we're designating in particular does it climb that much; maybe a total of about 30 feet, but in general, there are several silty or shaley sand zones in the designated Chacra area. I'm saying designated, designated by New Mexico by that number, I don't recall it offhand, but it was 750 feet below the bentonite. Okay, we're talking about the sandy zone that's about 100 feet below the bentonite and goes to 300 feet.

As far as I know, the next sandy zone, which is about 200 feet below that, has never been tested, and so I couldn't really say whether or not it has productive potential. I don't believe that it does.

But as far as we are concerned, the order may read just 310 feet, or whatever, being the first sands below the bentonite.

Q. Will Dome continue to drill to depths below that, the perforated interval, say -- what I'm looking at here on your Exhibit Four-A, the first well on the left, Dome Petroleum Navajo 17-22-7 No. 2, it shows the base of your perforated interval is still 150 feet above the TD of

the well.

A. Yes. We will continue to drill down there, I believe.

There was some thinking, if you'll look at the porosity curves on these logs, you'll see that below where we perforated in those wells, as matter of fact, on the Benson Federal 26-22-7 they did complete in that lowermost sand zone. If you'll notice, there are three sort of sandy zones, and in the lowermost sand zone they did complete.

Well, we have done some testing in some wells, two wells, completion testing where we selectively perforated and treated, and the C, or the lower, this lower portion here, the third sandy zone, as we call it, did not appear to give up very much gas.

Now we've only done this in two wells so we're not, you know, 100 percent sure that this is the case all the time, but we're -- I think we'll continue to drill down 300 feet through the Chacra, in the top of the Chacra.

Q. That is why you want to include that lower interval in the application today.

A. Yes, there's still probably testing yet to be done.

Q. On the wells which were plotted on the

Horner plot showing the calculations of permeability, were any initial potential tests run on those wells?

A. Yes, there were. On the Horner plot itself we show a gas rate on here; for instance, the Dome Federal 19-22-6 No. 1, the Q in the equation is the test rate prior to the shut-in for that well, and in this case it was 275 Mcf a day.

Q. And this is after treatment, then?

A. Yeah, it has to be after treatment because prior to treatment we could not get the wells to produce anything to get a drawdown in the reservoir pressure, to come up with this type of analysis, and because it was after the treatment it also took very long shut-in times. These were run eight to ten days.

Q. Did the plots indicate any skin damage which might have shown a reduced volume without the fracture treatment?

A. I didn't show that information on here. They were negative skin, so it showed stimulation from the fracture treatment.

MR. CHAVEZ: I have no further questions.

MR. STAMETS: The testimony here has been that the wells produced no crude oil. Do they produce any condensate?

A. No, they do not.

MR. STAMETS: So absolutely dry gas.

A. Yes, sir.

MR. STAMETS: Now, the -- we've been told here that all the gas wells shown on Exhibit Two are Chacra gas wells and looking at that it would appear as though each one of these wells is developing a single 160-acre proration unit, is that correct?

A. That is correct.

MR. STAMETS: And the -- there is no Division order relative to this area that calls for or permits an infill drilling program, is that correct?

A. To the best of my knowledge, that is correct.

MR. STAMETS: Okay. From your study of the records were any of the wells cored through the Chacra section?

A. Yes, there were several cores within the area here.

MR. STAMETS: Did you review that data to see what information was given relative to permeability?

A. Yes, I did review it. There are four cores that I'm aware of and I did review them for permeability data.

The permeability data that was measured on the cores was after they were cleaned and dried and were measured at surface conditions to air as a medium flowing through the core, and for that reason I did not include that information because it was not really representative of the reservoir rock at in situ conditions in the reservoir. I felt that the Horner plot better tells us what the permeability of the gas is at reservoir conditions rather than the core data.

MR. STAMETS: Did the core data show conditions very close to what you estimated here or much higher?

A. The average on the core data was about .3 of a millidarcy, compared to our .07 that we're testifying to here. In fact, two of the wells that we have these extended pressure build-up plots were wells that were cored. And we have direct comparison of core permeability to a Horner plot permeability from those two wells.

MR. STAMETS: I believe submission of that data would be most helpful to the Examiner.

A. Let me dig it out.

Okay, the four wells that have cores that I'm familiar with are the Dome Federal 19-22-6 No. 1, which had an average core permeability to air at surface con-

ditions at .324 millidarcies.

Okay, the second one is the Benson Navajo 21 No. 1, which is in Section 21 of 22 North, 7 West, the average core permeability was .209 millidarcies.

The third well is the Dome Federal 15-22-7 No. 1, with an average core permeability of .455.

And the fourth is the Dome Navajo 20-22-7 No. 1 with a core permeability of .384 millidarcies.

The first and the fourth well that I just read off to you are two of the wells with the Horner plots.

The first one, the Dome Federal 19-22-6 No. 1 for comparison had a Horner build-up plot of .04 millidarcies compared to the core permeability of .324.

The fourt one was the Dome Navajo 20-22-7 No. 1 with a Horner build-up of .05 millidarcies and the core permeability of .384.

There are papers in the literature that recognize that core permeability, especially in the tight, low permeability rock, are not particularly representative of in situ conditions and the permeability of the gas.

One major factor off the bat would be that water saturation is not taken into consideration and these tight rocks have very high water saturations and low,

low gas saturations in the reservoir.

There are just a lot of reasons that we felt that core permeabilities were not representative of the actual in situ permeability gas, which is the way the rules are written.

MR. STAMETS: Were there any drill stem tests, to your knowledge?

A. None that I'm aware of.

MR. STAMETS: Then Exhibit Number Eleven does show wells which were perforated and swabbed dry and then were these, from your examination of wells were tested at that point to see if they had any natural flow?

A. Yes, they were. Most of these wells, such as the Dome wells here, we took an extra two days of swabbing the well down and making sure we had a good, valid test at an unstimulated rate. We took an additional time and expense to gather the information for this hearing.

MR. STAMETS: And the one well on there, the Dome State No. 2 Well, the only well that showed any unstimulated production, test what may be the highest 3-hour potential after frac of --

A. Of the whole area.

MR. STAMETS: -- in any well.

A. Yes, sir.

MR. STAMETS: So do you feel that that's evidence to indicate that essentially everywhere in this area you will have too small to measure as your nonstimulated rate?

A. That's my conclusion, that this is one of the very best wells in the whole area and it even reached the requirements of the guidelines. It's below the 59 Mcf per day rate.

MR. STAMETS: Yes, sir? Would you identify yourself for the record, please?

MR. COLE: Yes, sir. My name is Jack Cole. I've drilled nine or ten wells in this area and am also included in this exhibit, and before the days we were worried about tight sand type things, a year and a half ago when I drilled my Alamos Canyon No. 2, we -- we swabbed it down also to see if we would get a -- because it was the first well I completed down there, to see what kind of natural flow it would get. We did not test it over a significant period of time, but we had no flow rate, no, not even a fume, and we went ahead and fraced and that well made just a shade under a million on initial potential.

MR. STAMETS: Thank you, Mr. Cole, we appreciate that.

Referring to Exhibit Twelve you indicated

that this type of completion process would protect any fresh water in the area. Is this the type of completion that State and Federal regulations and processes is requiring for the area?

A. To the best of my knowledge it meets all State and Federal requirements in the area.

MR. STAMETS: Are there other questions? Mr. Chavez?

MR. CHAVEZ: I have one more question for the witness.

QUESTIONS BY MR. CHAVEZ:

Q. On this Horner plot, Exhibit Nine-A, for Gulf Navajo 20-26-7 No. 1, he shows an "H", which is the thickness of the sand, that's what's represented, isn't it?

A. Yes.

Q. Of 100 feet. Then on Exhibit Number Seven, page four, in that well we show a sand thickness or a perforation -- completion interval that's only 33 feet thick, and by using that figure we get a "K", or permeability, of .1424. Is there one reason that --

A. Well, the 100 feet shown on our Exhibit Nine-A, represents calculated feet of sand that we felt we had open to production in the well, although only 33 feet

of perforations were there, the fracture stimulation opened up the whole interval.

Q. Do you have any tracers or any temperature surveys that show that?

A. Not on this particular well. We have done radioactive tracers surveys after fracs to show what -- what interval was -- how the fracture height was growing in these wells, and in most cases it was all of these permeable sands were opened up to production by means of the fracture stimulation.

Q. Is it normal to expect a horizontal fracture in these kinds of sands?

A. No, it's a vertical fracture.

Q. I'm sorry, a vertical fracture?

A. Yes.

Q. And this 100 feet is representative of the type of fractures that are opened up in any of these Chacra wells with a 33 foot perforated interval?

A. Well, the perforated interval varies a lot from well to well. I feel it is representative that this is -- these are the porous sands that we counted off of the logs that we felt were opened up by the fracture treatment.

MR. CHAVEZ: I have no further questions.

RECROSS EXAMINATION

BY MR. STAMETS:

Q. What is the typical fracture treatment, then, or the cost of said treatment?

A. Well, a typical size -- different operators have different approaches to this. Ours have been recently foam fracture jobs with 30 to 90,000 pounds of sand, depending on how much interval we have perforated. That's -- that range is probably typical.

The cost would be anywhere from $15 to $40,000, depending on how large a frac job you had planned for the well, and it's definitely a significant, very significant, part of the well cost.

Q. What do these wells cost in this area now?

A. Between $100 and $150,000 per well, including frac, and any production equipment.

Q. What types of reserves do you feel are being developed on a per well basis?

A. Well, that's a tough question right now because we don't have very much production history on of the wells. They're all shut-in waiting on pipeline.

We're hoping to recover on the order

of -- I'm trying to remember -- 200-million cubic feet per well.

I might point out that there are some producing wells in the area and their ultimate recovery is going to be much less than that. Currently they're averaging about 10 Mcf per day per well after three years of production.

MR. STAMETS: Any other questions of the witness? Either witness? They are both excused.

Anything further in this case?

The case will be taken under advisement.

(Hearing concluded.)

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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 CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7300, heard by me on 7/2, 1981.

Richard L. Stamets, Examiner
Oil Conservation Division

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

CASE 7300

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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I N D E X

KEVIN TRACY

Direct Examination by Mr. Bateman 4

Questions by Mr. Chavez 20

E X H I B I T S

Applicant Exhibit Thirteen, Build-up Data 4

Applicant Exhibit Fourteen, Well Cost Estimate 12

Applicant Exhibit Fifteen, Operating Costs 13

Applicant Exhibit Sixteen, Economic Data 14

Applicant Exhibit Seventeen, Graphs 17

Applicant Exhibit Eighteen, Economic Info. 18

Applicant Exhibit Nineteen, Economic Info. 18

Applicant Exhibit Twenty, Summary 18

MR. STAMETS: We'll call next Case 7300. It has been heard and previously taken under advisement, but it's being reopened today for submittal of some additional information.

MR. PEARCE: And it is application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

MR. BATEMAN: Mr. Examiner, I'm Ken Bateman of White, Koch, Kelly, and McCarthy, and I have one witness.

(Witness sworn.)

MR. BATEMAN: Mr. Examiner, inasmuch as this case has been -- was heard previously on July the 2nd, I'd like to dispense with the qualifications of the witness. We have the same witness.

MR. STAMETS: The same witness who was previously qualified?

MR. BATEMAN: Correct.

MR. STAMETS: Yes, he is still considered qualified.

MR. BATEMAN: It is our intention to present additional data concerning the permeability calcula-

tion as well as the econonic data which was presented at the previous hearing on July 2nd, 1981.

KEVIN TRACY

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you again, however, state your name for the record?

A. Kevin Tracy.

Q. And your place of employment and position?

A. I'm a Senior Reservoir Engineer for Dome Petroleu, Denver, Colorado.

Q. In connection with this application have you made calculations of permeability, average permeability for the area in question?

A. Yes, I have, and it was presented at the last hearing.

Q. Let's proceed, then, with what's been marked Exhibit Thirteen, A, B, and C, and would you please elaborate on the detail of the information used for calcu-

lating the in situ permeability in the area?

A. Exhibits Thirteen A, B, and C are additional detail of -- to show how the permeability number was calculated for each of the three wells that had extended pressure build-up tests.

Thirteen A concerns the Chase Rusty Federal No. 4. I'd like to first list all the attachments here.

Attached is an open flow potential test write-up; a copy of the Horner build-up plot from the last hearing; a copy of the pressure versus square root of Delta T plot from the last hearing; the field data of pressure and time; a copy of the gamma ray density log section over the Chacra zone; and copies of several correlations of natural gas properties used in obtaining some of the values in the equation for calculating permeability.

Now, I'll go through what the significance of those attachments are.

The field data is included to show the gas rate, time and casing pressures that are recorded during the test of this well.

The one point test write-up is included to show where the formation temperature and the gas gravity came from. Formation temperature being 92 degrees Fahrenheit,

which was converted to degrees ranging in the equation.

The gas gravity of .626 was used in the correlations of natural gas properties to obtain some other properties of gas.

Viscosity of the gas was evaluated at an average pressure and the average being the sum of the flowing pressure and final shut-in pressure divided by two; in the case of this well, 380 psi.

The gas properties were evaluated at that pressure.

Knowing the reservoir temperature, the pressure of interest, and the gas gravity, one of the correlation charts attached is used to get a gas viscosity; in this case, .012 centipoise.

In the equation for permeability the z factor is the real gas deviation factor and in order to get that number pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psi were obtained from the correlation charts. Using those and the average pressure and the reservoir temperature previously shown we get the pseudo reduced pressure and pseudo reduced temperature.

Using those two numbers you go on to another correlation chart, also attached, to get the z factor of .94.

In the equation q is the producing gas rate in Mcf per day and this well's build-up was 627 Mcf per day, which is the last measured rate prior to shutting in the well for the pressure build-up.

T is the producing time in hours and was corrected for any fluctuations in producing rate by taking the cumulative production during the test, dividing by the final rate and multiplying by 24 hours per day.

Delta T is the shut-in time read directly from the field data sheet.

H in the equation is the thickness of pay contributing to production. In this case it was 52 feet. This number was taken from the log evaluation of the Chacra in the well in which any porous zones above 8 percent porosity were included, subtracting any shale breaks.

And it's my opinion that an 8 percent cutoff is reasonable in this area in that zones of 8 percent porosity are contributing to production.

I'd like to go now to the additional detail for pressure build-up analysis on the Dome Navajo 20-22-7 No. 1.

And included as attachments to this write-up are the field data; a copy of the gamma ray density log; the Horner plot from the previous hearing; the pressure

versus square root of Delta T plot; and eight gas analyses for Chacra Wells in the area.

The field data was used once again for the pressure and time use on the plots. Flowing time for the purposes of calculating superposition time in the Horner plot was cumulative production during the test divided by the final flow rate times 24, to get 8.72 hours.

Since a gas analysis was not available for this particular well, the average from eight other gas analyses in the area was used for gas gravity. An average of .63 was obtained.

Using .63 a pseudocritical pressure of 367 degrees -- well, excuse me, let me go back. Pseudocritical temperature and pseudocritical pressure of 367 degrees R and 670 psia were obtained. An average pressure was determined to be 362 psi by averaging the flowing pressure and final shut-in pressure.

The reservoir temperature was assumed to be the same as that recorded during the pressure build-up test in the Dome Federal 19-22-6 No. 1, which was 166 degrees. That was converted to degrees to get 626 degrees R.

Pseudoreduced temperature and pseudo-reduced pressure were then calculated and used in a correlation chart to get the real gas deviation factor of .97.

Using a different correlation chart the gas viscosity of .012 centipoise was obtained.

Q, the gas production rate in Mcf per day was the final recorded rate before shutting in the well; in this case, 101 Mcf per day.

And Delta T in the equation was the shut-in time, which was taken directly from the field data.

Formation thickness contributing to production was determined to be 100 feet for this well by adding up the permeable zones with porosity greater than 8 percent, as taken off the gamma ray density log.

In this particular well there is a bridge plug at 1525, which isolates two sets of perforations in the wellbore. The pay below that bridge plug was also included because we felt that after fracture stimulation of the upper zone communication was re-established with the lower perforations.

During prior operations in the well communication was shown between upper perfs and lower perfs during squeeze operation. After squeezing the upper perfs were re-opened and the well was fracture stimulated.

However, if you just include the pay above the bridge plug, which is 41 feet in this case, the permeability for the well of .115 millidarcy is obtained,

which averaged with the other two is still below the tenth of a millidarcy requirements for tight gas incentive pricing.

And the last write-up is additional detail for pressure build-up analysis for the Dome Federal 19-22-6 No. 1, and included as attachments to that are once again the Horner plot; the plot of pressure versus the square root of Delta T; the field data; and a copy of the gamma ray density log.

Flow rates,bottom hole pressure, bottom hole temperature; times were taken from the field data sheet.

Flowing time for the purposes of calculating superposition time in the Horner plot is calculated by dividing the cumulative production during the test by final flow rate times 24 to get 10.26 hours.

Since the gas analysis was not available for this well, the previous average of eight gas analyses in the area was used in the correlation charts of gas properties.

Pseudocritical temperature and pseudocritical pressure of 367 and 670 degrees R and psia were obtained. An average pressure for evaluating gas properties of 671 psi was obtained by averaging the flowing pressure and the final shut-in pressure.

A reservoir temperature of 166 degrees Fahrenheit was converted to 626 degrees R and this temperature

and average pressure were used to -- with the pseudoreduced temperature and pseudoreduced pressure in order to get the real gas deviation factor of .97.

Gas viscosity was estimated at the average pressure to be .0121 centipoise.

The gas flow rate used in the equation of permeability was 275 Mcf per day, which is the final rate reported before the well was shut-in.

And Delta t in the plots was the shut-in time which was also taken directly from the field data.

Formation thickness used in the equation for this well was 105 feet, which was determined from the gamma ray density log by adding up the porous zones with porosity greater than eight percent.

Q. Were there any other wells available in this area for analysis on the Horner plot basis?

A. No other wells had pressure build-ups of sufficient time to reach the straight line on a Horner build-up plot, which takes from eight to ten days in these tight reservoirs.

Q. The length of time is a factor of the tight formation, I take it?

A. Yes.

Q. In your opinion is a Horner plot a reliable

method of estimating the in situ permeability?

A. In my opinion it's the best method of measuring in situ permeability, since it is taken at reservoir conditions and we don't have to correct for them or estimate the effect of water saturation or overburden pressure.

Q. Again for the record, what was your estimate of the average in situ porosity in this area?

A. You mean permeability?

Q. Permeability, excuse me.

A. .07 millidarcy.

Q. And do you believe that's a reliable average for all the wells in question?

A. I believe it is for the reason that the three wells that we have extended pressure build-up tests on are in the middle of the field and, if anything, would represent some of the better part of the reservoir.

Q. Now, with Exhibit Number Fourteen, we've prepared a well cost estimate in this area.

A. Yes. The Exhibit Fourteen is a well cost estimate to drill and complete a Chacra well within our application area, assuming that it would be drilled the first half of next year.

Of significance on this cost estimate sheet is the total well cost of $162,300. The $30,000 stimu-

lation treatment cost estimate, which is the cost for the fracture and stimulation of the well, represents a signficant part of the well costs, and also that, as later we'll see, the tangibles and intangibles split becomes important in the economics of the well; the intangible being $120,360; the tangible being $41,940.

Q. Have you calculated the detail of operating costs?

A. Yes. Exhibit Fifteen is the detail of what our estimated operating costs will be when we start producing the wells in this area. If I can just go down it, in dollars per well per month we've estimated $120 for lease operator; $36 for vehicle operation and repair; compression costs, as far as operating a compressor, allocated back to each well would be $418; maintenance of the compressor $70 per well per month; pumping unit operation $15 per month; we expect to have to pump the water off these wells to make them -- to get them to produce anything at all; and well repair and maintenance $125 per month. That's taken from $1500 per year per well average for pumping unit repair and any type of small acid jobs that might be required.

The total then would be rounded off at $780 per well per month.

Q. You have wells in the area that are not

currently producing, is that correct?

A. That's correct. We have 20 wells in the area that we operate that are waiting on a gathering system.

There's a total of 70 wells that have tested the Chacra in the area, of which only 14 are now on production.

Q. Would you proceed then with what's been marked Exhibit Sixteen and state what your economic assumptions are?

A. Exhibit Sixteen shows the economic assumptions used in evaluating these wells.

First of all, we show gas prices and how we forecast them to increase. We show three categories of gas, NGPA Section 102, which is new well gas, with an actual October, 1981 price of $2.91. In our forecasts shown in the next few tables we escalate that 1 percent per month until 1982 and then we increase that gas price with inflation plus 4 percent until $10 an Mcf is reached, at which time the gas price is held constant.

The next category of gas in NGPA Section 108, which is stripper well gas, for an actual October price of $3.116 per Mcf. Actually it's dollars per million BTU but we've assumed 1000 BTU gas. The escalation would be the

same as NGPA 102.

The third category is NGPA Section 107, which is tight well gas, with an actual October '81 price of $5.03, roughly, per Mcf. We've escalated that 1 percent per month until 1982. Then we escalate it with inflation only until $10 per Mcf is reached.

And throughout our forecasts here we assumed inflation to be 10 percent per year beginning in 1982.

Operating costs were inflated at that 10 percent per year rate until the gas prices peaked at $10 an Mcf; then they also were held constant.

Okay, tangible drilling costs, we depreciated over a five year life by means of 150 percent declining balance changing to a straight line depreciation method in the second year.

Investment tax credit of 10 percent was also included in the evaluation.

As far as taxes, we've included State severance tax on gas of 12.6 cents per Mcf; Federal Income Tax was assumed to be 46 percent, which is the corporate tax rate; and a State income tax of 5 percent was also included.

For the purpose of the forecast shown here, we assume 100 percent working interest with total royalty burdens 16-2/3rds percent, which is representative for this

area.

Q. Did you calculate a production decline?

A. Yes, for analogy we have plotted the declines of all the fourteen producing wells in the area that are operated by Chase. Those are all shown as a package as Exhibit Seventeen. Of particular significance is the field average for the fourteen wells, which shows gas rate in Mcf per month versus time, and these wells began production in the beginning of 1978, and we've plotted through mid-year 1981.

The average well started production at 58 Mcf per day and currently on a daily average is only 9 Mcf per day. The decline rate shown here is 36.6 percent per year.

Another curve that is used in our evaluation is a plot of the well with the best cumulative production to date, and that's the Rusty Navajo No. 2.

This production forecast -- well, actual production was used in our forecast with 8 percent decline after mid-'81.

The initial potential on the 3-hour test is shown in the upper righthand corner for all these individual wells. In this case it was 802 Mcf per day, which plotted on this curve is 24-million per month, which is sig-

nificantly above what the well actually stabilized at for the first month.

Q. So then you've based your economic projections both on an average well basis and on a best well basis, is that correct?

A. That's correct.

Q. It's calculated from the production decline figures which you've just testified to?

A. That's correct.

Q. You've also calculated them based on a before income tax and an after tax basis, is that also correct?

A. Right.

Q. And you've compared Section 108 pricing with Section 107, the tight gas pricing, is that correct?

A. That's right.

Q. Will you state, then, for the Examiner what your conclusions are with respect to necessity for price incentives in this particular area?

A. Well, it becomes very clear that incentive pricing is needed to give a reasonable rate of return, even on our best well basis.

On the average well production forecasts the well won't pay out either with stripper gas prices or tight gas prices.

So a net loss in both cases.

Q. Do you expect by stimulation methods to achieve production greater than the average well figures that you have here?

A. Well, when we -- when Dome first got involved in the area we felt confident that we could do at least as well as these existing Chase operated wells, but we didn't have a lot of production decline history to look at and as time went on we saw that decline was steeper than we were forecasting for our wells and we're still hopeful that the changes we've made in stimulation procedures and in operating techniques will cause our wells to produce at rates closer to the best well case rather than the average; however, there is certainly great risk that ours would be no better than the average well.

Q. The economic forecast is contained in Exhibits Eighteen, Nineteen A and Nineteen B, is that correct?

A. That's correct.

Q. Would you refer to Exhibit Twenty and state what -- or give a summary of your evaluation, please?

A. Okay. A couple of the economic yardsticks used by most companies to evaluate a prospect or a well, a producing well in this case, are the after income tax discounted cash flow, and we show cash flow discounted 15 per-

cent and at 20 percent for the average well case and the best well case, both at the two pricing schemes involved.

The average well case has negative discounted cash flow at both 15 and 20 percent in both pricing cases.

The best well, using stripper gas prices, has a negative cash flow at 15 percent and 20 percent, while with tight gas pricing it would have a positive cash flow at both of those discount rates.

The rate of return on the best well case is 13 percent using stripper pricing forecast and 32 percent using stripper gas price forecasts.

Our payout on the best well case was five years for stripper pricing and 2.2 years for the tight gas pricing case.

Q. Plus payout would not be achieved on the average well case, is that correct?

A. That's correct.

Q. In your opinion would further development occur in this particular area without pricing incentives?

A. In my opinion it would not.

Q. Do you believe the authorization of the tight gas pricing that you've requested is in the best interest of the production in this area, the prevention of waste, and

the protection of correlative rights?

A. Yes.

Q. Were Exhibits Thirteen -- excuse me, yes, Thirteen through Nineteen prepared by you or under your direction?

A. Yes, they were, Exhibits through Twenty.

Q. Through Twenty, excuse me.

MR. BATEMAN: I have no further direct.

MR. STAMETS: The exhibits will be admitted.

Are there questions of the witness? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Tracy, for the record there are three wells that you've done back -- I'm sorry, back pressure tests and two of them were completed with limited entry and one was completed in a conventional completion.

Could you explain what the difference is between those types of completion and why they are done?

A. Well, we've tried several different completion techniques in the area and with inconclusive results.

The limited entry technique would have

fewer perforations in the casing spread further apart with the expectation that a fracture stimulation would be better controlled that way, if you'd get fracture directed to the zones where you want it, with some more control, and the perforations would then be communicated by means of the vertical fracture between the large spaced perforations.

Conventional technique would be to perforate just the areas of high porosity. In all cases the wells have been fracture stimulated and just fracturing, hoping that the fracture fluids and sand would be distributed through those intervals which we have perforated either way.

As I said, we have inconclusive results on which way is working the best for us at this time, mainly because our wells have been completed and just had an IP test run, the 3-hour or initial potential test, and we don't have any production history to compare the long term effects of the different completion techniques.

Q. Did you do any radioactive tracer survey after limited entry fracs?

A. Not in this area.

Q. On Exhibit Number Thirteen A, for the Chase Rusty Federal No. 4, you've used an h factor of 51 feet by counting the porosity intervals that had more than 8 percent, is that correct?

A. 52 feet, I believe, is the number I used, that's correct.

Q. Oh, 52 feet. Yet this is a conventional completion, not a limited entry completion, and doesn't the industry -- standard industry practice in a situation like this require that your h factor used in permeability calculations be only the -- the perforated intervals?

A. No, it's my belief that industry practice is to include log calculated pay that any -- that is contributing to production. For instance, the perforations at the top of this well, there's 4 feet perforated from 1758 to 1762, where on the density curve it appears that there's a sand there of about 11 feet in thickness of which only 4 feet of that was included in the perforations.

Now it's my opinion that there is vertical permeability in that 11 foot sand and therefor the gas at the top of the sand is also being produced in the wellbore through those 4 feet.

Q. So what we'll have there, then, is gas from the sandstone layers 6 feet above the top perforation flowing vertically down through the perforations?

A. That's right.

MR. STAMETS: While we're right there, why not perforate the entire section?

A. Well, if you feel like, as the operator apparently did, that the 4 feet of perforations on that interval were sufficient to drain the 11 feet of sand, it was a way of saving money on these wells that are already marginal.

Q. On the log that is part of that exhibit, it seems as if the -- let's see if I'm correct here. The 10 percent porosity line is the darker line -- well, let me identify it for you. That's 10 percent.

A. Right.

Q. It seems as if the perforations are more on the next line, is that 12 percent porosity? Those seem to correlate more with the perforations than the 10 percent or 8 percent porosity line does.

A. That's probably right. The conventional technique is to perf just the highest porosity, but that doesn't preclude gas from the lower porosity zones through vertical permeability being produced into the wellbore.

MR. STAMETS: Maybe I should have asked, if this had been Dome Petroleum's well, would you have perforated that entire interval?

A. Well, we've -- as I say, the results aren't back yet on whether limited entry or conventional perforating techniques are better in the long run, and we've tried both. We've done -- done them both ways.

MR. STAMETS: It would be fair to say, though, that you're convinced that that entire 11 foot section is productive and you would intend to use whatever completion technique achieved maximum production therefrom.

A. Right. That's correct.

Q. Okay, on the Dome Navajo 20-22-7 No. 1, a question comes to my mind about whether or not or how you determined that there was vertical flow from beneath the bridge plug into the upper portion of the well. How was that determined?

A. Okay. As far as current communication from the lower zone to the upper zone, that is strictly my opinion based on the prior history of the well.

The well is completed in two stages with perforations below 1525 in the first stage. They perforated, acidized, and fracture stimulated in that lower zone. Then the upperforations were made in the casing, and the well was acidized and a sand problem started where it was felt that sand was coming in from the perforations at about 1530.

So a cement retainer was set at 1525 and they pumped into the cement retainer and got pressure communication to the casing annulus immediately upon pumping.

To me that is -- that is the reason that I think that there's likely communication there. After

pumping into the cement retainer and seeing communication through the upper perfs, all the upper perfs were squeezed and reperforated and then a fracture stimulation was done on the well and the well IP tested; initial potential test was made, and it's my opinion that when they fracture stimulated the upper perforations they re-established communication to the lowermost zones.

Q. Now how do you determine that?

A. Only because of the communication that existed prior to squeezing those perfs and the high pressures involved in the fracture stimulation and the nature of vertical fracturing in these reservoirs. It's not a proven fact. It is, you know, an opinion.

Q. Well, there's no evidence on -- I'll hand you a copy of the daily drilling report for that well. Can you show me anywhere on there where it might indicate there was communication at that last fracture in the upper perfs?

A. Well, no, it's just my opinion by the nature of the high pressure, hydraulic fracture stimulation, that communication was re-established. The production from the lower zone is very similar to the production from the upper zone and no actual tracers or injection surveys were done to scientifically pin down that. There's nothing on

here that definitely, you know, it is a fact you can point at and say that's communication.

But nonetheless, even if you just include the area in the upper part of the well above the bridge plug, the average permeability is still less than a tenth millidarcy criteria.

Q. You have previously testified originally in this case that you would consider as productive those portions of the Chacra formation that had porosity of 10 percent or greater.

A. That was the testimony given by our geologist at the hearing, Michael Fuchs. He was testifying as to how we picked the limits of our application area, and how we go about picking well locations.

If a well had on his contour map showed zero feet of greater than 10 percent porosity we wouldn't drill it. That doesn't mean that a well with only 8 percent porosity wouldn't have a gas production rate, and in our opinion it wouldn't be a commercial well if it didn't have any porosity greater than 10 percent.

Q. How was the cumulative gas produced during these tests measured, did you start measuring immediately after flow back after fracture?

A. Well, no, these tests were done at a

later date after the fracture stimulation was done, the wells were shut-in for months and we came back to do the special testing required to get a long enough build-up for the Horner plot.

Gas flow rates were measured hourly, I believe. It's on the field data sheet there, the gas rates recorded at different times.

Q. So what you did was you just got the cumulative gas off that open flow?

A. Well, it's off of an 8-hour drawdown prior to the 8-day build-up.

The wells were certainly stabilized at reservoir pressure after being shut-in several months before we ran these special tests.

Q. Turning to your economics, Exhibit Number Sixteen, why did you use an NGPA price of Section 102 rather than Section 103 for the Rusty Chacra?

A. The Rusty Chacra area did not be in production until 1978 and from most of the area there was no production within 2-1/2 miles. Most of it will qualify as 102. There are a few areas that I'm aware of where it was old Gallup gas production that might be 103 rather than 102.

And that only comes in effect on the

best well case the very first year, because that is the only case where gas production rates were above the stripper rate of 60 Mcf a day.

Q. What is the distribution of the royalty burden that give you a working interest -- I'm sorry, that give you a 16.6 royalty for the average? It would be the combination of the --

A. Well --

Q. -- Navajo, Federal, and State royalties?

A. Well, actually our Navajo leases are burdened with 16-2/3rds percent royalty rate. Federal leases have less, but there are also overrides involved in a lot of the leases we've picked up from other companies in the area.

So we, rather than try to compute all the royalty rates in the area and come up with a real average, we used what the majority of our leases are in the area, or Navajo leases.

Q. So that was just more of an assumption rather than an actual calculated --

A. That's correct.

Q. On average Rusty Chacra well you show a Section 108, or stripper price that gives you only a four year productive life for the well with a cumulative of less than 30 MMCF.

A. That's correct. The economic forecast shown here stops when the economic limit is reached, when operating costs exceed revenue.

Q. The economically recoverable reserves, then, in your best well case as shown in Exhibit Twenty, are 162.3 and then 115.3 MMCF.

A. No, that's the --

Q. For Section 108, and 118 MMCF for Section 107?

A. That's correct.

Q. Do you have calculated -- or a listing of calculated recoverable reserves for the wells that you have now drilled in the Chacra, Rusty Chacra Field?

A. No, I don't. And really, before we can accurately evaluate that, we have to get all wells on production and see if they behave similarly to these older wells in the field, and forecast declines.

Volumetric in these tight, low pressure reservoirs are -- are inaccurate because really the controlling factor is when you reach the economic limit, not whether you recover all the gas in place.

Q. Do you think your -- the Dome wells in the Rusty Chacra Field will have a slower decline and better production rate than the original Chase wells because of the

improved completion techniques?

A. Well, that remains to be seen. We're hopeful that they'll be similar to the best Chase well producing out there now, which is our best well case.

Whether they exceed that or not, I really don't feel confident that they will.

Q. In computing your cash flow at a 15 percent discount rate, is that the cost of the equity involved in investments for these wells?

A. Well, the costs of -- cost of capital varies from company to company and the source of your funding.

We just showed 15 percent as a discount rate and 20 percent as a second one, rather than what our actual cost of capital is.

Q. Well, based on a project like this, would Dome finance this with equity or with debt, which would change, of course, the -- are you qualified to speak to this?

A. I really can't answer that question.

MR. STAMETS: Somebody is going to pay for it with debt some place.

Q. What's been the rate of return that Dome has supplied its equity owners this last year, or are you qualified to speak to that?

A. I'm really not qualified to speak to that, either. Sorry.

MR. CHAVEZ: I don't have any further questions.

MR. STAMETS: Any other questions of this witness? He may be excused.

Anything further in this case?

MR. BATEMAN: Nothing further.

MR. STAMETS: The case will be taken under advisement.

(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. _____, heard by me on _____ 19____.

_____, Examiner
Oil Conservation Division

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

United States Department of the Interior

OFFICE OF THE SECRETARY
Minerals Management Service
South Central Region
P. O. Box 26124
Albuquerque, New Mexico 87125

OIL CONSERVATION DIVISION
SANTA FE

FEB 04 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. 7300, Order No. R-6874, dated January 11, 1982, that the Chacra formation underlying the described lands in subject order in Sandoval 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 and Gas

ECONOMIC ASSUMPTIONS

Gas Prices

NGPA	Oct. '81 Price $/MCF	Escalation
103	2.909	Escalate 1% per month until 1/82 then inflation + 4% until $10/MCF is reached.
108	3.116	Same Escalation as NGPA 102
107	5.028	Escalate 1% per month until 1/82 then escalate with inflation until $10/MCF is reached.

Inflation

Inflation was assumed to be 10% per year beginning in 1982. Operting costs were inflated until gas prices peaked at $10/MCF then operating costs were also held constant.

Depreciation and Investment Credit

Tangible drilling costs were depreciated over a 5 year life by means of a 150% declining balance to a straight line depreciation method. An investment tax credit of 10% of the tangible drilling costs is also included.

Taxes

State severance tax on gas production of 12.6 cents/MCF is included. Federal Income tax of 46% and state income tax of 5% is also included.

Working Interest, Royalty Interest

Working interest was assumed to be 100% and royalty burdens were assumed to be 16.667%.

RUSTY CHACRA AVERAGE WELL
Economic Detail

Before Income Tax

	NGPA Section 108					Gross Production		NGPA Section 107				
Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $	MCF/D	MCF/Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $
82	3.42	37640	9360	1385	26895	36	13192	5.44	59790	9360	1385	49045
83	3.90	27827	10296	898	16632	23	8555	5.98	42651	10296	898	31457
84	4.45	17420	11326	493	5602	13	4698	6.58	25764	11326	493	13945
85	4.99	11364	10110	287	968	9	3202	7.24	19316	12458	336	6522
86						7	2521	7.95	16709	13392	265	3052
TOTAL		94251	41092	3063	50096		32168		164231	56832	3378	104022

After Income Tax*

			NGPA Section 108				NGPA Section 107			
Yr	Depreciation $	Investment Credit $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $
82	6291	4194	26895	-99756	-55070	-80336	49045	-77606	-43773	-69482
83	9227		16632	7406	3777	12856	31457	22230	11337	20120
84	8807		5602	- 3206	- 1635	7237	13945	5138	2620	11325
85	8807		968	- 7840	- 3998	4966	6522	-2286	-1166	7687
86	8807						3052	-5755	-2935	5987
TOTAL	41940	4194	50096	-103396	-56926	-55278	104022	-58278	-33916	-24362

* Includes capital costs of $41,940 Tangible and $120,360 Intangible.

RUSTY CHACRA BEST WELL
Economic Detail

Before Income Tax

	NGPA Section 108					Gross Production		NGPA Section 107				
Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $	MCF/D	MCF/Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $
82	3.21*	64235	9360	2521	52354	66	24014	5.44	108839	9360	2521	96958
83	3.90	56239	10296	1815	44127	47	17290	5.98	86200	10296	1815	74089
84	4.45	33580	11326	951	21304	20	9056	6.58	49664	11326	951	37388
85	5.07	30647	12458	761	17428	20	7250	7.24	43736	12458	761	30516
86	5.78	33521	13704	730	19086	19	6956	7.96	46158	13704	730	31724
87	6.59	35156	15074	672	19410	18	6399	8.76	46712	15074	672	30966
88	7.52	36872	16582	618	19672	16	5888	9.64	47273	16582	618	30073
89	8.57	38671	18240	569	19863	15	5417	10.00	45134	18240	569	26325
90	9.77	40559	20064	523	19971	14	4983	10.00	41523	18240	523	22760
91	10.00	38204	20064	481	17659	13	4585	10.00	38201	18240	481	19480
92	10.00	35148	20064	443	14641	12	4218	10.00	35145	18240	443	16462
93	10.00	32336	20064	407	11865	11	3880	10.00	32333	18240	407	13686
94	10.00	29749	20064	375	9310	10	3570	10.00	29747	18240	375	11132
95	10.00	27369	20064	345	6960	9	3284	10.00	27367	18240	345	8782
96	10.00	25180	20064	317	4798	8	3022	10.00	25178	18240	317	6620
97	10.00	23165	20064	292	2809	8	2780	10.00	23163	18240	292	4632
98	10.00	21312	20064	269	980	7	2557	10.00	21310	18240	269	2802
99	10.00	1670	1643	21	6	6	2353	10.00	19606	18240	247	1119
00						6	497	10.00	4144	4054	52	38
TOTAL		603613	289259	12111	302243		117999		771434	293494	12389	465551

*First year assumes NGPA 102 price since well would not qualify for NGPA 108 until second year.

RUSTY CHACRA BEST WELL
Economic Detail

After Income Tax*

Yr	Depreciation $	Investment Credit $	NGPA Section 108 Net Income $	NGPA Section 108 Net Taxable Income $	NGPA Section 108 Income Tax $	NGPA Section 108 Cash Flow After Tax $	NGPA Section 107 Net Income $	NGPA Section 107 Net Taxable Income $	NGPA Section 107 Income Tax $	NGPA Section 107 Cash Flow After Tax $
82	6291	4194	52354	-74297	-42086	-67861	96958	-29693	-19338	-46005
83	9227		44127	34900	17799	26328	74089	64862	33080	41009
84	8807		21304	12496	6373	14931	37388	28580	14576	22812
85	8807		17428	8620	4396	13031	30516	21709	11072	19445
86	8807		19086	10279	5242	13844	31724	22916	11687	20036
87			19410	19410	9899	9511	30966	30966	15793	15173
88			19672	19672	10033	9639	30073	30073	15337	14736
89			19863	19863	10130	9733	26325	26325	13426	12899
90			19971	19971	10185	9786	22760	22760	11607	11152
91			17659	17659	9006	8653	19480	19480	9935	9545
92			14641	14641	7467	7174	16462	16462	8396	8066
93			11865	11865	6051	5814	13686	13686	6980	6706
94			9310	9310	4748	4562	11132	11132	5677	5455
95			6960	6960	3550	3411	8782	8782	4479	4303
96			4798	4798	2447	2351	6620	6620	3376	3244
97			2809	2809	1433	1377	4632	4632	2362	2269
98			980	980	500	480	2802	2802	1429	1373
99			6	6	3	3	1119	1119	570	548
00							38	38	20	19
TOTAL	41940	4194	302243	139943	67177	72766	465551	303251	150464	152787

* Includes capital costs of $41,940 Tangible and $120,360 Intangible.

RUSTY CHACRA
SUMMARY OF
ECONOMIC EVALUATIONS

	AVERAGE WELL		BEST WELL	
NGPA Section	108	107	108	107
Gross Reserves (MMCF)	29.2	32.3	115.3	118.0
Investment (M$)	162.3	162.3	162.3	162.3
BEFORE INCOME TAX				
Undiscounted Cash Flow (M$)	-112.2	-58.3	139.9	303.3
Cash Flow at 15% Discount Rate (M$)	-119.2	-75.6	2.3	109.6
Cash Flow at 20% Discount Rate (M$)	-121.0	-80.0	-18.5	78.8
Rate of Return (%)	0	0	15.5	45.2
Payout (Yrs.)	--	--	5.4	1.9
AFTER INCOME TAX				
Undiscounted Cash Flow (M$)	-55.3	-24.4	72.8	152.8
Cash Flow at 15% Discount Rate (M$)	-67.3	-43.5	-5.4	47.2
Cash Flow at 20% Discount Rate (M$)	-70.5	-48.4	-18.3	29.4
Rate of Return (%)	0	0	13.3	32.3
Payout (Yrs.)	--	--	5.0	2.2

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION

OCT 19 1981
OIL CONSERVATION DIVISION
SANTA FE

October 14, 1981

Oil Conservation Division
Energy and Minerals Departments
State of New Mexico
State Capitol
P.O. Box 2088
Santa Fe, New Mexico 87503
Attention: Miss Florine Davidson

Re: Case No. 7300 (Rehearing) in the matter of the application of Dome Petroleum corporation for Designation of a Tight Formation, Sandoval County, New Mexico

Dear Florine:

In connection with the rehearing of the application in Case No. 7300, I enclose three sets of Exhibits which are proposed for the hearing set on October 21, 1981.

As information, we will require a review of the exhibits already introduced in the case at the first hearing on July 2, 1981.

Thank you for your assistance.

Sincerely,

KENNETH BATEMAN

KB/bah
Enclosures

Mailing Address: P.O. Box 787, Santa Fe, N.M. 87501
Street Address: 220 Otero St., Santa Fe, N.M. 87501 (505) 982-4374

L. C. White
Sumner S. Koch — *Larry C. White*
William Booker Kelly — *Forrest S. Smith*
John F. McCarthy, Jr. — *John N. Patterson*
Kenneth Bateman — *Paula Tackett*
Benjamin Phillips — *Filmore E. Rose*

Attorneys and Counselors at Law

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
AZTEC DISTRICT OFFICE

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

1000 RIO BRAZOS ROAD
AZTEC, NEW MEXICO 87410
(505) 334-6178

August 14, 1981

Response to Supplemental Info to RFL

RECEIVED
AUG 17 1981
OIL CONS. DIVISION
SANTA FE

Mr. Richard Stamets
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: Case #7300

Dear Dick:

The information submitted by Dome after the hearing does not indicate that the lower perforations are or were communicating with the upper perforations in the Dome Navajo 20-22-7 #1. If Dome can show that there was communication, they will also need to show that the earlier volume of gas produced from the lower perforations was considered in the "q" value used in the calculations. The "limited entry" technique has been accepted by the industry, however, Dome should submit for the record the tracer surveys, reference literature, etc., to show the effect of the technique in this particular well and in general. If they can supply this information, we should be able to accept their corrected calculated permeability of 0.15 md on exhibit 9A.

Exhibit 8A uses "h" or net pay factor of 52'. Well records show that the Chace Rusty Federal #4 has the following perforations: 1758-62 w/2spf, 1766-68 w/2spf, 1773-81 w/8spf, 1789-93 w/2spf, and 1798-1801 w/2spf, for total of 21' of perforations. As this is not a limited entry completion, industry practice is to consider only the perforated intervals as "net pay." The resulting calculated permeability is 0.331 md. Dome will need to explain why they use a net pay figure of 52' amd a supercompressibility factor of 0.94 instead of 0.97 as in the other exhibits.

Exhibit 10A for the Dome Federal 19-22-6 #1 uses an "h" factor of 105'. Well records show the following perforations: 1698'-1744' w/13 jet shots and 1772'-1805' w/19 jet shots for a total of 79'. However, as this is a limited entry completion if we use Dome's criterion of considering the intervals of 10% porosity or greater as net pay we find only 70' of net pay. (See attached copy of log.) Using the 70' as "h" in the Horner equation results in a permeability of .0446 md.

By using the revised permeabilities, we find that the average permeability from the exhibits is .175 md.

If the Horner method of calculating permeability is used in future hearings, the witnesses should supply for reference the data to support the figures which are used in the Horner equation. They should also supply the statistical data to show that sampling techniques used in selecting the number of samples are valid. For example: Do three wells out of seventy nine constitute a statistically representative sample? If not, to what degree?

I recommend that unless Dome can supply the data to justify their exhibits, their application be denied.

Yours truly

Frank T. Chavez

Frank.T. Chavez
District Supervisor

K+E SEMI-LOGARITHMIC 1 CYCLE X 10 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

$$kh = \frac{1637(\mu)(t)(z)(q)}{m}$$

$$= \frac{1637(.0121)(626)(.97)(101)}{258458}$$

$$= 4.7$$

h=100 k=.047

m=258458 PSI^2/cycle

$p^2 \times 10^{-3}$

170
160
150
140

Assume: p^2 vs. $\frac{t+\Delta t}{\Delta t}$ straight line

$\mu = .0121$ cp
$z = .97$
$t = 626°R$
$q = 101$ MCFD

$K = .074$

$kh = \frac{1637(.0121)(.97)(626)(4.58)}{258458} = 21.35$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 9
CASE NO. 7300
Submitted by Dome
Hearing Date 7/24/81

1 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ (t=8.72hrs.)

EXHIBIT 9A

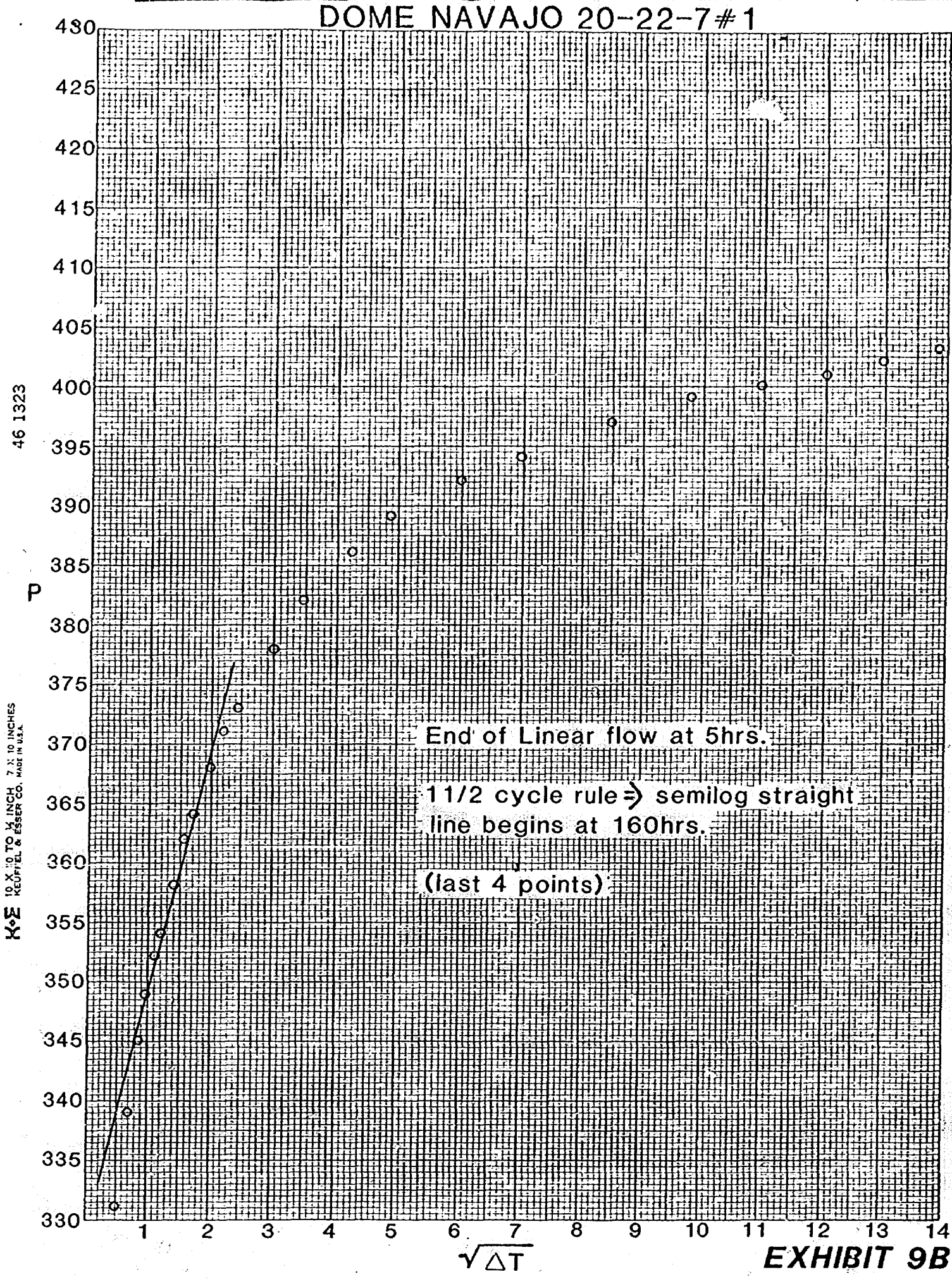


EXHIBIT 9B

20

Dome Navajo
20-22-7*J

CORE #1

1487-91'
5 holes

1496'
1 hole
1500

1504'-
08'
5 holes

1512'-
24'
7 holes

CORE #2

1530'
1 hole

1535'
1 hole

1552'-
57'
6 holes

1574'-
78'
3 holes

1592'-
96'
3 holes
1600

K_h = 4.7

K_v = .094

GR

10'

5'

10'

Stage #2
16,25,000 gal
20 SPM, 20 holes

12'

7'

4'

13' Stage #1
18,000 gal
3' 15 SPM, 12 holes

10'

10'

50

h = 100'

20

10

POROSITY

K•E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

NOTE: Page 36, lines 4, 5 & 6 of Transcript

m=924,985 PSI^2/cycle

Assume p^2 vs. $\frac{t+\Delta t}{\Delta t}$ straight line

μ = .012 centipoise
z = .94
t = 627°R
q = 1423

$$kh = \frac{1637(\mu)(z)(t)(q)}{m} = \frac{1637(.012)(.94)(555)(627)}{924,985} = 6.95$$

h=52' k=.13

$$Kh = \frac{1637(\mu)(z)(t)(q)}{m} = \frac{1637(.012)(.94)(627)(1423)}{924,985} = 12.91$$

Let h = 52'

k = .3425

well = communicated with

p^2 X10^{-3}

280
260
240
220
200
180
160
140

1.0 2 3 4 5 6 7 8 9 10.

$\frac{t+\Delta t}{\Delta t}$ (t=8hrs.)

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 8
CASE NO. 7348

Submitted by
Hearing Date 7/2/80

EXHIBIT 8A

K•E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

CHASE/RUSTY/FED. #4

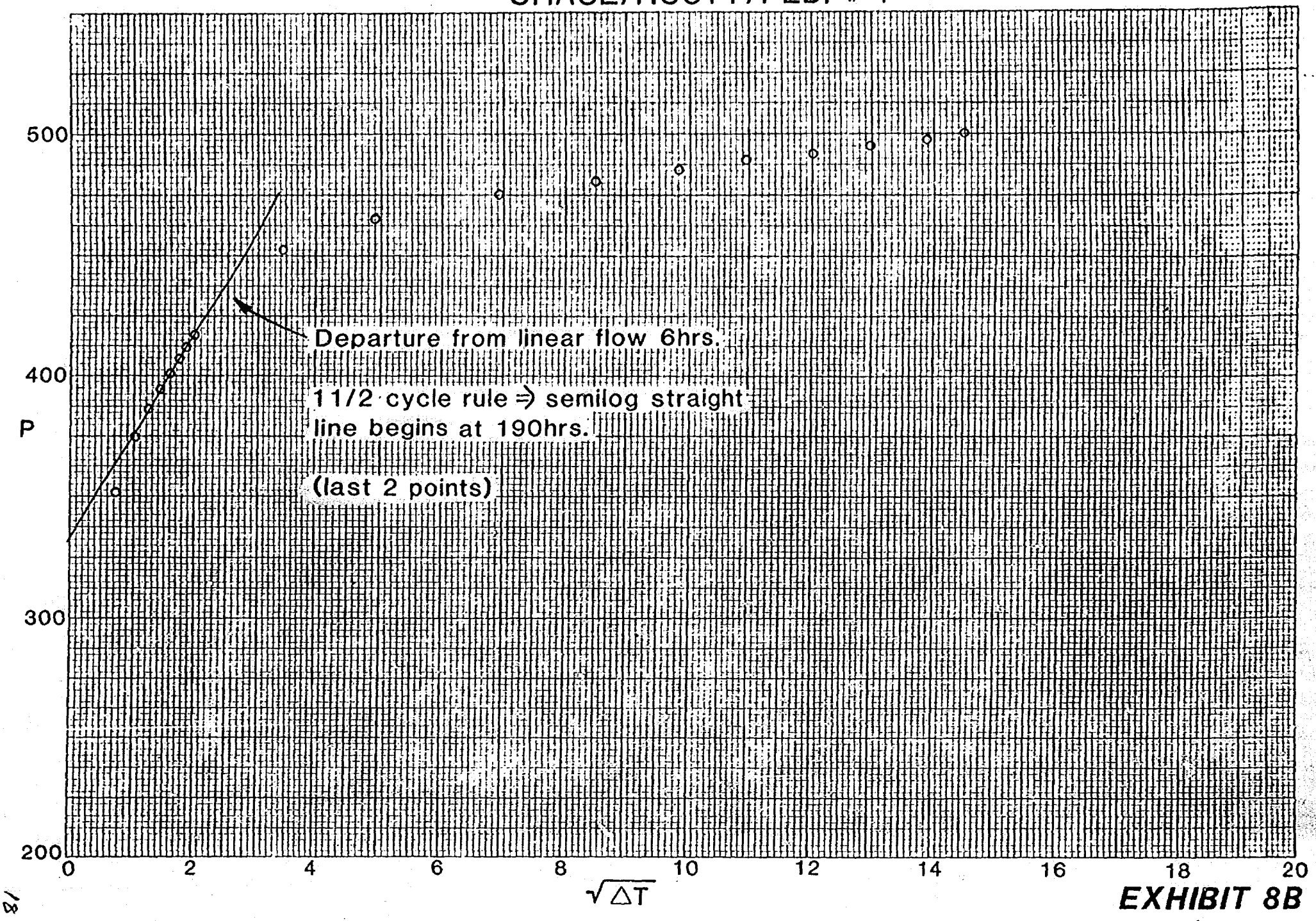


EXHIBIT 8B

SW/SW
Sec 13
T22-R7

1700

CHASE
RUSTY
FED. #4

1738+5178
Chacra A

1758-62

1766-68

1773-81

1789-93

1800

1798-1801

1820+5096
Chacra B

Caliper Curve

Gamma Ray

1872

1891+5025
Chacra C

GR FR

1900

10

11'

10%

43'

14'

9'

BULK DENSITY

Geo.

52

10%

31'

7'

11%

COMPENSATION

Wet

POROSITY

95

K

POROSITY

30

20

K•Σ SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME/FED. 19-22-6#1

$kh = \frac{1637(\mu)(q)(z)(t)}{m}$

$= \frac{1637(.0121)(275)(.97)(626)}{1,060,161}$

$= 3.12$

$h = 105$ $k = .03$

$m = 1,060,161\ PSI^2/cycle$

Assume μ = .0121 cent
z = .97
t = 626
q = 359

$kh = \frac{1637(.0121)(.97)(626)(359)}{1060161}$

$= 4.078$

$k = .038$

Average of all 3 = 4.15 md

p^2 X 10^{-3}

Hearing Date 7/28

Submitted by Conoco

CASE NO. 7300

OIL CONSERVATION DIVISION
EXHIBIT NO. 16

BEFORE EXAMINER STAMETS

$\frac{t+\Delta t}{\Delta t}$ (t=10.26 hrs.)

EXHIBIT 10A

DOME FED. 19-22-6#1

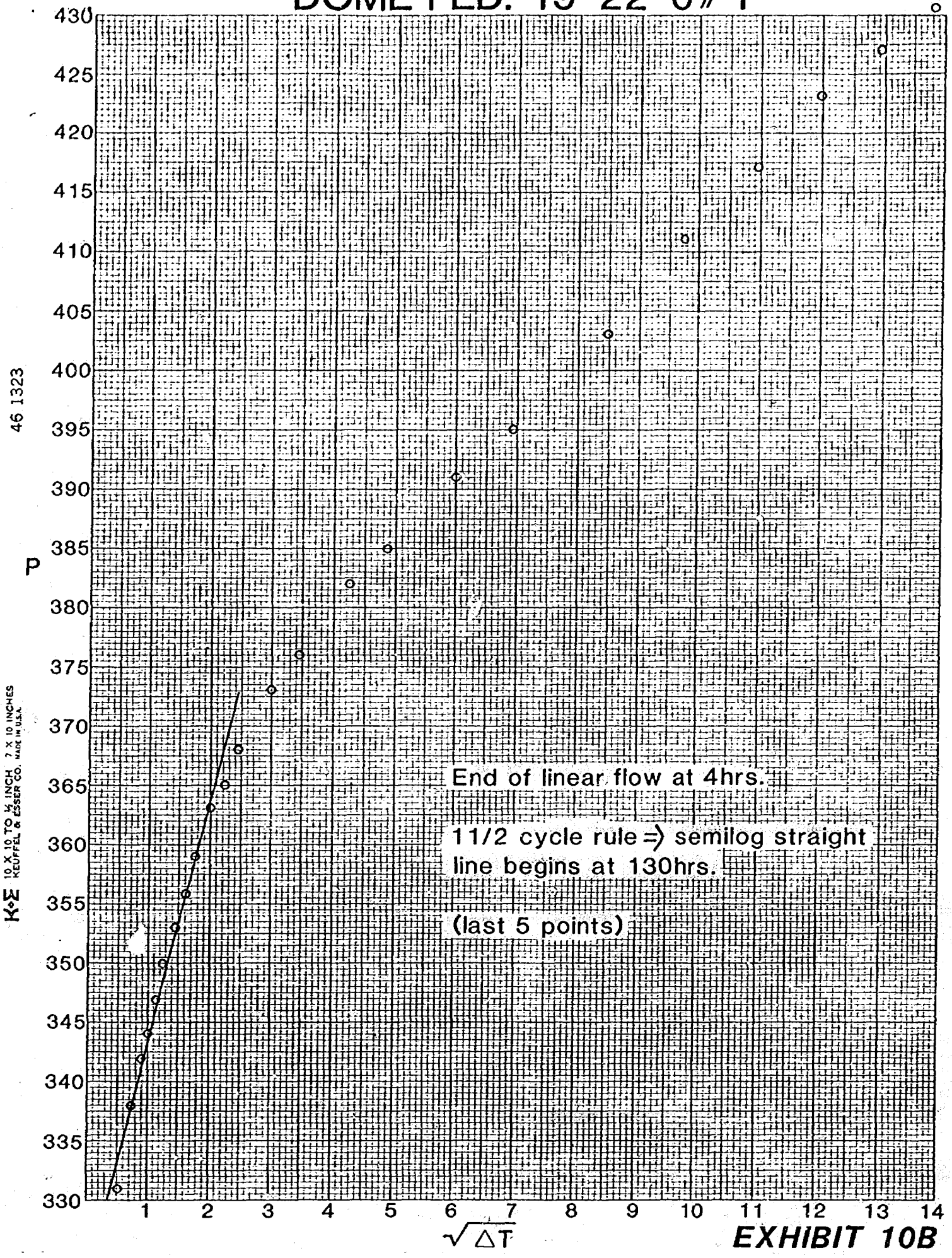


EXHIBIT 10B

22

Dome
Fed.
19-22-6
#1

Perf. 1698-1700
2 holes

Perf 1708
1 hole

Perf.
1714-22
5 holes

Perf.
1724-
36 ? holes

Perf
1738-44
4 holes

Perf.
1772-79
8 holes

Perf.
1794-96
3 holes

Perf.
1804-05
2 holes

CORE 1

CORE 2

GR

2'
6'
44'
30'
8'
6'
105'

Kh = 3.12

k = 0.495

POROSITY

30 20 10 0

STAGE 2
FOAM FRAC 32,000 gal

Memo

From

PRENTISS CHILDS
Planner

To

$$kh = \frac{1632(u)(z)(t)q}{m}$$

(8) $u = .012$

$z = .94$

$t = 555°R$ ~~$627°R$~~

$q = 627$ ~~555~~ 1423

(9) $u = .0121$

$z = .97$

$t = 626°R$

$q = 101$ (15-8)

(10) $u = .0121$ $t = 626°R$

$z = .97$ $q = 275$ (359)

NORTHWEST EXPLORATION COMPANY

D. J. ECKELBERG
VICE PRESIDENT, EXPLORATION

RECEIVED
JUN 25 1981
OIL CONSERVATION DIVISION
SANTA FE

P. O. BOX 5800 TERMINAL ANNEX
1125 SEVENTEENTH STREET
DENVER, COLORADO 80217
303-820-3503

June 23, 1981

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Case 7300

Gentlemen:

Re: Dome Petroleum's Application
for Tight Gas Designation for
the Chacra formation, Sandoval
County, New Mexico

Northwest Exploration Company has been informed that Dome Petroleum will present the captioned application for hearing on July 2, 1981, before the Oil Conservation Division of the State of New Mexico.

Northwest and its partners own approximately 8,000 acres of oil and gas leases within the area of application. As indicated in Dome's application, Northwest Exploration has drilled and completed two Chacra Sand gas wells located in Sections 11 and 12 of Township 21 North, Range 6 West, Sandoval County, New Mexico. These wells were drilled in 1979 and have been shut in, waiting on pipeline connection.

Northwest, as operator, supports the application of Dome Petroleum for tight gas sand designation and recommends that the State of New Mexico grant its approval. Assuming that approval of the State and the USGS and the Federal Energy Regulatory Commission be granted, Northwest Exploration intends to undertake a drilling program to develop our leasehold.

Sincerely,

D. J. Eckelberg

D. J. Eckelberg
Vice President/Exploration

DJE:tks
cc: K. F. Tracy
Dome Petroleum Corp.
2900 Dome Tower
1625 Broadway
Denver, Colorado 80202

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. 7300
Order No. R-6874

APPLICATION OF DOME PETROLEUM
CORPORATION FOR DESIGNATION OF
A TIGHT FORMATION, SANDOVAL
COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on July 2, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets and was readvertised and reopened at a hearing held at 9 a.m. on October 21, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets.

NOW, on this 11th 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, Dome Petroleum Corporation, requests that the Division in accordance with Section 107 of the Natural Gas Policy Act, and 18 C.F.R. §271.703, recommend to the Federal Energy Regulatory Commission that the Chacra formation underlying the following lands situated in Sandoval County, New Mexico, hereinafter referred to as the Chacra formation, be designated as a tight formation in the said Federal Energy Regulatory Commission's regulations:

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections 6 through 8: All
Sections 16 through 22: All
Sections 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 18: All
Sections 20 through 27: All
Sections 35 through 36: All

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 4: All
Sections 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections 6 through 8: All
Sections 16 through 22: All
Sections 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST,NNMPM
Sections 1 through 36: All

Containing 73,017.58 acres, more or less.

(3) That the Chacra formation underlies all of the above described lands; that the formation consists of fine grained and clay filled transitional shaly sands and silt stones; that the top of such formation is found at an average depth of 1658 feet below the surface of the area set forth in Finding No. (2) above; that the thickness of said formation varies with an average thickness of 300 feet within said area.

(4) That the type section for the Chacra formation for the proposed tight formation designation is found at a depth of approximately 1946 feet to 2340 feet on the Birdwell density and neutron and induction electric logs dated April 5, 1980 and September 6, 1980, respectively, of the Dome Federal 20-22-6 No. 2 Rusty Chacra located in Unit P of Section 20, Township 22 North, Range 6 West, NMPM, Sandoval County, New Mexico.

(5) That the Chacra formation underlying the above described lands has been penetrated by 70 wells of which only fourteen are currently producing natural gas in commercial quantities from the Chacra formation.

(6) That based on an analysis of available data from existing wells within the proposed area and utilizing generally and customarily accepted petroleum engineering techniques and measurements:

(a) the estimated average in situ gas permeability throughout the pay section of the Chacra formation is expected to be 0.1 millidarcy or less; and

(b) the stabilized production rate, against atmospheric, of wells completed for production in the Chacra formation, without stimulation, is not expected to exceed production levels determined by reference to well depth, as found in the table set out in 18 C.F.R. §271.703(c)(2)(B) of the regulations; and

(c) no well drilled into the Chacra formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

(7) That the Chacra formation underlying the area described in Paragraph 2 hereof is not being developed by infill drilling.

(8) That the evidence presented in this case demonstrated that the application of incentive pricing is reasonably necessary to stimulate further development of the proposed tight formation underlying the area described in Paragraph 2 hereof.

(9) That within the proposed area there is a recognized aquifer being the Ojo Alamo, found at a depth of from 500 feet to 1100 feet or approximately 1158 to 558 feet above the Chacra formation.

(10) That existing State of New Mexico and Federal Regulations relating to casing and cementing of wells will assure that development of the Chacra formation will not adversely affect the said aquifers.

(11) That the Chacra formation should be recommended to the Federal Energy Regulatory Commission for designation as a tight formation.

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. §271.703 of the regulations that the Chacra formation underlying the following described lands in Sandoval County, New Mexico, be designated as a tight formation:

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections 6 through 8: All
Sections 16 through 22: All
Sections 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 18: All
Sections 20 through 27: All
Sections 35 through 36: All

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 4: All
Sections 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections 6 through 8: All
Sections 16 through 22: All
Sections 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

Containing 73,017.58 acres, more or less.

(2) That jurisdiction of this cause is hereby 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

SEAL

fd/

RUSTY CHACRA AREA

Detail of Operating Cost

	$/Well/Month
Lease Operator	120
Vehicle operation and repair	36
Compression costs - operating	418
Compression costs - maintainence	70
Pumping unit operating cost	15
Well repair and maintainence	125
TOTAL	784

Say $780/well/month

(14)

DOME PETROLEUM CORP.

WELL COST ESTIMATE

Form 049-A

OPERATOR Dome Petroleum Corp. AFE NO. _____
WELL NAME Typical Rusty Chacra Well NO. _____ DATE 10/5/81
LOCATION _____ PREPARED BY R. S. Kelley
COUNTY Sandoval STATE New Mexico APPROVED BY _____
PROJECT DESCRIPTION _____

	DRILLING INTANGIBLES	DESCRIPTION	AFE AMOUNT
302-001	Stake Location, Permits, Damages		$ 500.00
302-003	Location, Roads, Lease Restoration		3,000.00
302-004	Rig Mobilization/Demobilization		2,000.00
302-005	Footage-Drlg 2,200 /ft. @ $ 10 /ft.		22,000.00
302-006	Daywork 2 days @ $ 2,880 /day		5,760.00
302-007	Fuel		
302-008	Bits		
302-009	Equipment Rental - Drilling		
302-010	Water		3,000.00
302-011	Drilling - Mud/Additives		2,500.00
302-015	Cement & Services		1,500.00
302-021	Transportation - Drilling		
302-036	Services & Contract Labor, Welding & Casing Crew		
302-012	Coring	302-013 DST	
302-014	Open Hole Logging		4,500.00
302-016	Mud Logging	302-017 Geological - Services & Expenses	
302-018	Engineering	302-019 Supervision 8 days 302-020 Overhead - Drilling	2,400.00
302-022	P & A, & Environmental Concerns		2,000.00
302-024	Miscellaneous Equipment & Supplies - Drilling		2,000.00
		SUBTOTAL INTANGIBLES	$51,160.00
	DRILLING TANGIBLES		
303-001	Surface Casing 120' - 8 5/8"		1,860.00
303-002	Intermediate Casing		
303-004	Casing Accessories - Drilling		500.00
303-005	Casing Head		600.00
		SUBTOTAL TANGIBLES	$2,960.00
		CONTINGENCIES 15%	7,670.00
		TOTAL DRY HOLE COST	$61,790.00
	COMPLETION INTANGIBLES		
302-037	Dirt Work - Road & Location		$ 500.00
302-002	Permanent Damages, Permits		
302-025	Completion Unit 5 days @ $ 1,100 /day		5,500.00
302-026	Equipment Rental - Completion		2,500.00
302-027	Cased Hole Logging & Perforating		3,500.00
302-028	Stimulation & Treatment		30,000.00
302-029	Completion - Testing		
302-030	Cement & Services		5,000.00
302-038	Water - Completion Fluids		2,000.00
302-039	Services - Contract Labor/Welding/Casing Crew/Completion		1,000.00
302-040	Miscellaneous Equipment & Supplies - Completion transportation ect.		2,000.00
302-032	Engineering	302-033 Supervision 5 days 302-034 Overhead-Compl.	1,500.00
		SUBTOTAL INTANGIBLES	$53,500.00
	COMPLETION TANGIBLES		
303-003	Production Casing & Liner 2,200' - 4 1/2"		$12,520.00
303-015	Casing Accessories - Completion		1,000.00
303-006	Production Tubing 1700' - 2 3/8"		5,760.00
303-017	Wellhead - Christmas Tree		1,500.00
303-007	Subsurface Equipment, Bottom Hole Pump		1,500.00
303-013	Pumping Unit/Prime Mover API - 40		6,000.00
303-014	Rods, Sucker/Polished/Scraper		2,500.00
303-008	Tanks		
303-009	Separators - Treaters - Dehydrators		4,200.00
303-010	Flowlines		500.00
303-012	Installation		2,000.00
303-015	Valves, Fittings & Miscellaneous Equipment		1,500.00
303-019	Meters Oil-Gas, LACT		
303-011	Electrical Equipment		
		SUBTOTAL TANGIBLES	$38,980.00
		CONTINGENCIES 15%	8,030.00
		TOTAL COMPLETION COSTS	100,510.00
		TOTAL WELL COSTS	$162,300.00

ECONOMIC ASSUMPTIONS

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 16
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

Gas Prices

NGPA	Oct. '81 Price $/MCF	Escalation
102	2.909	Escalate 1% per month until 1/82 then inflation + 4% until $10/MCF is reached.
108	3.116	Same Escalation as NGPA 102
107	5.028	Escalate 1% per month until 1/82 then escalate with inflation until $10/MCF is reached.

Inflation

Inflation was assumed to be 10% per year beginning in 1982. Operting costs were inflated until gas prices peaked at $10/MCF then operating costs were also held constant.

Depreciation and Investment Credit

Tangible drilling costs were depreciated over a 5 year life by means of a 150% declining balance to a straight line depreciation method. An investment tax credit of 10% of the tangible drilling costs is also included.

Taxes

State severance tax on gas production of 12.6 cents/MCF is included. Federal Income tax of 46% and state income tax of 5% is also included.

Working Interest, Royalty Interest

Working interest was assumed to be 100% and royalty burdens were assumed to be 16.667%.

(13A)

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Chace Rusty Federal #4

Attached is a copy of the field data reported for an extended pressure buildup test on this well. Gas rate, time, and casing pressures were used in the evaluation of kh for this well. The casing pressure was corrected to bottom hole pressure at the midpoint of the perforated interval. (Roughly casing pressure plus 15 psi for the column of gas in the wellbore).

Also attached is a copy of a one point test and calculation of absolute open flow potential. From this form the reservoir temperature of 92 degrees F and gas gravity of .626 was obtained. Using this information the following variables were obtained for use in the calculation of kh, the permeability thickness and then k, the insitu permeability to gas.

T = Reservoir temperature 92 degrees F + 460 = 552 degrees R

μ = Viscosity of gas at average pressure conditions. Average pressure was obtained by averaging the flowing pressure and the final shut in pressure $\frac{245 + 519}{2} = 380$ psi

Fig. D.27 page 234 from Advances in Well Test Analysis by Robert C. Earlougher Jr. was then used to get a gas viscosity of .012 cp.

z = real gas deviation factor. Fig. D.3 page 223 of Advances in Well Test Analysis by Robert C. Earlougher Jr. was used to get pseudo critical temperature

and pressure of 367 degrees R and 670 psia respectively. Pseudo reduced pressure and temperature were then calculated as follows:

$$Ppr = \frac{380}{670} = .567$$

$$Tpr = \frac{552}{367} = 1.5$$

Then using Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr. a real gas deviation factor of .94 was obtained.

q = Producing gas rate in MCF/Day 627 MCF/D is the last rate measured before the well was shut in.

t = Production time in hours = 8 hrs, t = cumulative production during the test divided by final rate times 24 hrs/day.

$\triangle$ t = Shut in time in hours.

h = Thickness of pay contributing to production = 52'. This number was determined from porosity logs run in the well using an 8% porosity cut off and subtracting any shale breaks.

MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL

Revised 9-1-65

Type Test: [X] Initial [ ] Annual [ ] Special			Test Date: 11-20-75	
Company: Chace Oil Co.		Connection: Waiting on Pipeline		
Pool: Undesignated		Formation: Chacra		Unit
Completion Date: 10-26-75	Total Depth: 1974	Plug Back TD: 1943	Elevation: 6904 GR	Farm or Lease Name: Rusty Federal
Csg. Size: 4.500 / Wt.: 10.50 / d: 4.052 / Set At: 1972		Perforations: From 1758 To 1801		Well No.: 4
Tbg. Size: 1.900 / Wt.: 2.90 / d: 1.610 / Set At: 1803		Perforations: From Open To Ended		Unit: M / Sec.: 13 / Twp.: 22N / Rge.: 7W
Type Well – Single – Bradenhead – G.G. or G.O. Multiple: Single		Packer Set At: None		County: Sandoval
Producing Thru: Tubing	Reservoir Temp. °F: 92 @ 1915	Mean Annual Temp. °F: --	Baro. Press. – P_a: 12.0	State: New Mexico

L	H	Gg	% CO_2	% N_2	% H_2S	Prover	Meter Run	Taps
1803	1803	0.626	--	--	--	--	--	--

	FLOW DATA				TUBING DATA		CASING DATA		
NO.	Prover Line Size	X Orifice Size	Press. p.s.i.g.	Diff. h_w	Temp. °F	Press. p.s.i.g.	Temp. °F	Press. p.s.i.g.	Temp. °F	Duration of Flow
SI						480		490		10 da
1.	3/4"	THC			60	106		230		3 hr
2.										
3.										
4.										
5.										

RATE OF FLOW CALCULATIONS

NO.	Coefficient (24 Hour)	$\sqrt{h_w P_m}$	Pressure P_m	Flow Temp. Factor Ft.	Gravity Factor Fg	Super Compress. Factor, Fpv	Rate of Flow Q, Mcfd
1	12.3650		118	1.0000	0.9759	1.0000	1,423
2.							
3.							
4.							
5.							

NO.	P_r	Temp. °R	T_r	Z
1.				
2.				
3.				
4.				
5.				

Gas Liquid Hydrocarbon Ratio _____ Mcf/bbl.
A.P.I. Gravity of Liquid Hydrocarbons _____ Deg.
Specific Gravity Separator Gas _____ XXXXXXXXX
Specific Gravity Flowing Fluid _____ XXXXX
Critical Pressure _____ P.S.I.A. _____ P.S.I.A.
Critical Temperature _____ R _____ R

RECEIVED NOV 26 1975 OIL CON. COM.

P_c 502 P_c^2 252,004

NO	P_t^2	P_w	P_w^2	$P_c^2 - P_w^2$
1		242	58,564	193,440
2				
3				
4				
5				

(1) $\frac{P_c^2}{P_c^2 - P_w^2} = 1.3028$ (2) $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n = 1.2521$

AOF = Q $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n = 1,782$

Absolute Open Flow 1,782 Mcfd @ 15.025 | Angle of Slope θ _____ | Slope, n _____

Remarks: _____

Approved By Commission:	Conducted By:	Calculated By:	Checked By:
		Ewell N. Walsh	

K&E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

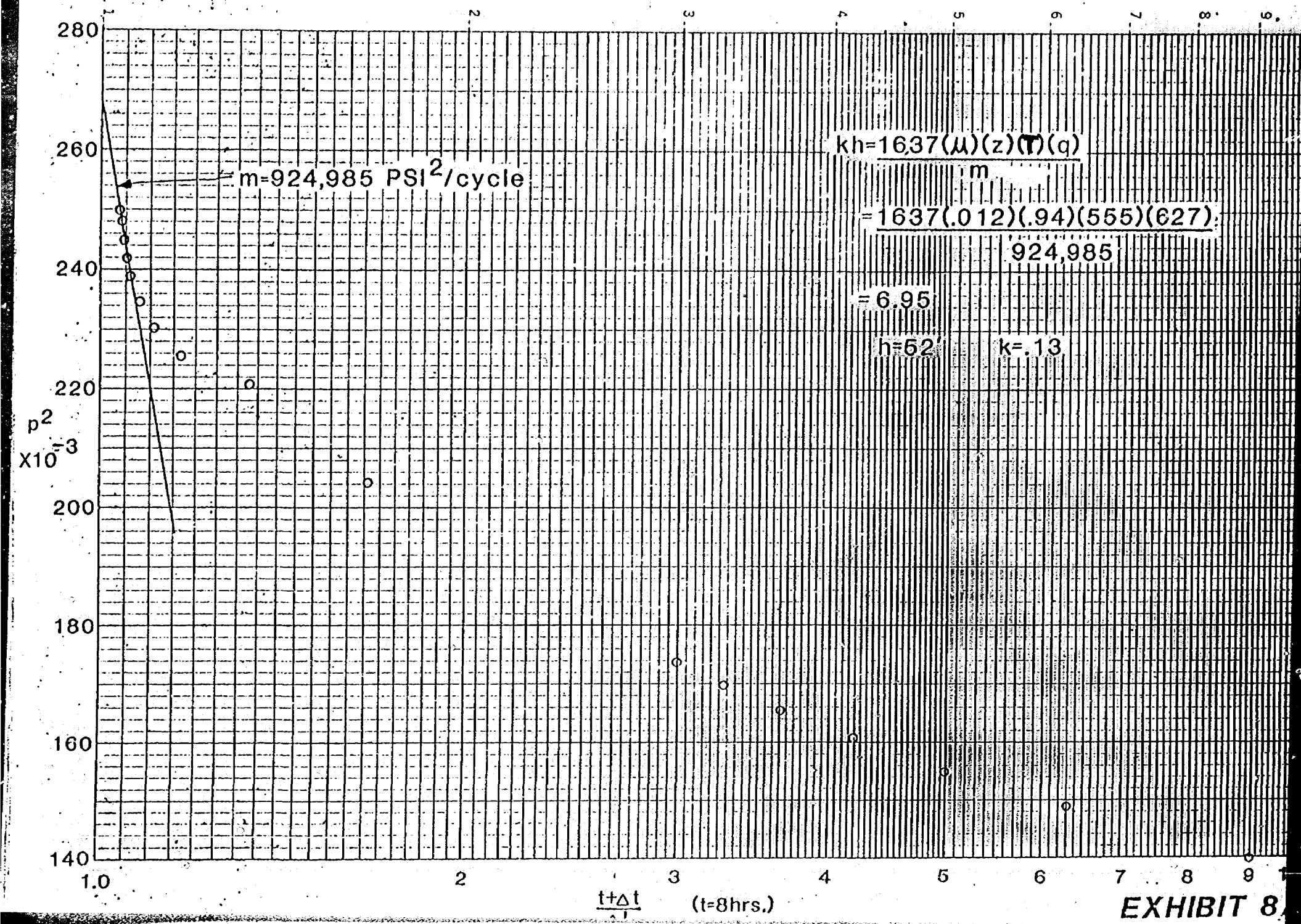
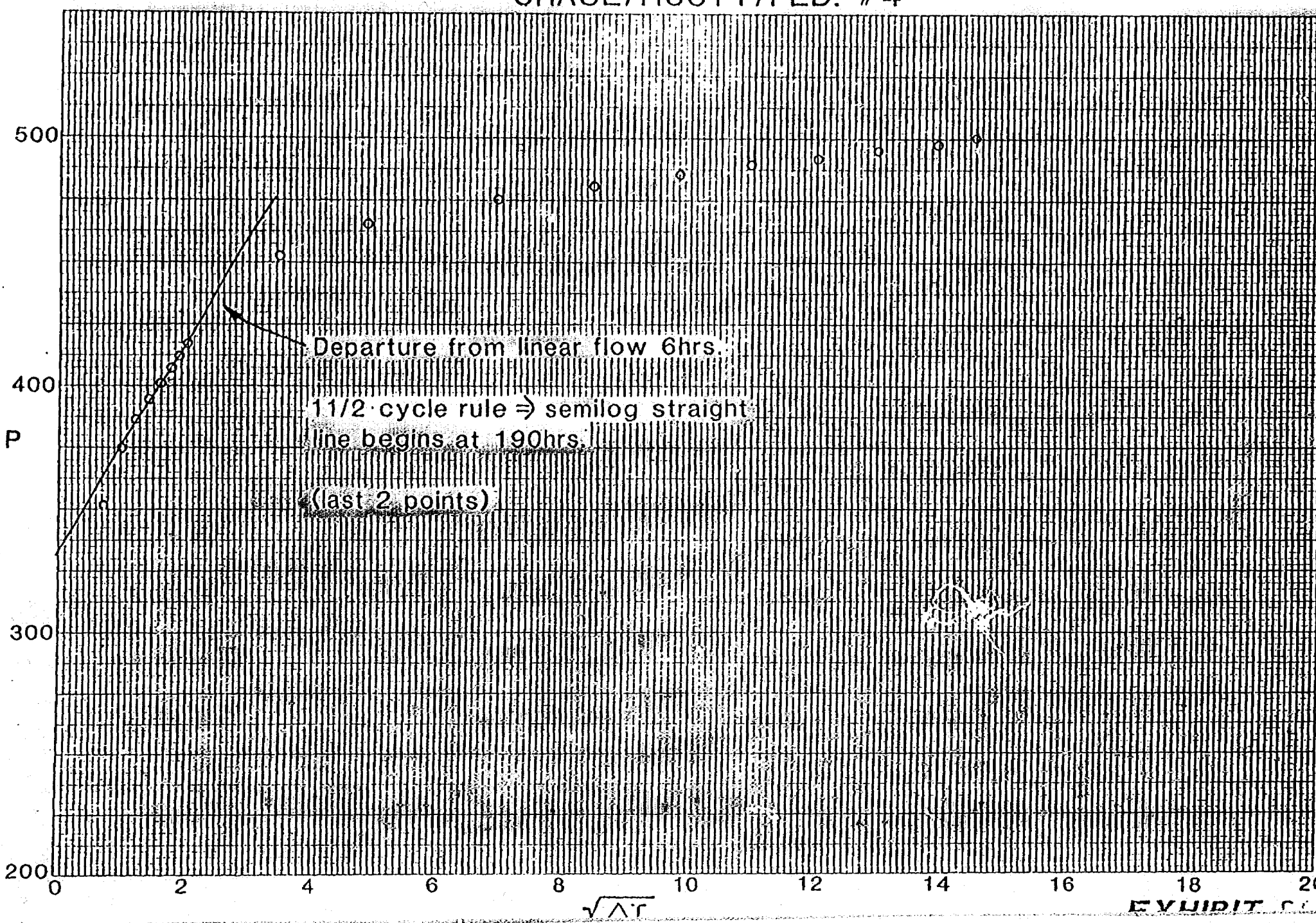


EXHIBIT 8

K&E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

CHASE/RUSTY/FED. #4



EXHIBIT

RUSTY FEDERAL NO. 4

SANDOVAL COUNTY, NEW MEXICO

800'S, 800'W, Sec. 13, T-22-N, R-7-W

DATE	TIME		CSG. PRESS. PSIG	TBG PRESS. PSIG	RATE MCF/D	VOL. TIME MCF	CUM. VOL. MCF	REMARKS
11-05-75	09:15		492	492				SI PRESSURE, WELL ON, 2" CRIT
	09:30		468	464	360	3.75	3.75	FLOW PROVER, 3/16" PLATE
	09:45		457	454	352	3.66	7.41	
	10:00		450	447	347	3.61	11.02	
	10:15		444	441	342	3.56	14.58	CHANGED TO A 1/4" PLATE
	10:30		425	418	579	6.03	20.61	
	10:45		416	409	567	5.91	26.52	
	11:00		408	400	555	5.78	32.30	
	11:15		402	394	547	5.70	38.00	CHANGED TO A 3/8" PLATE
	11:30		339	308	943	9.82	47.82	
	11:45		318	286	878	9.15	56.97	WELL STARTED MAKING A FINE SP OF WATER
	12:00		304	284	871	9.08	66.05	
	12:15		291	262	806	8.39	74.44	CHANGED TO A 1/2" PLATE
	12:30		244	185	1042	10.86	85.30	
	12:45		220	167	947	9.87	95.17	
	13:00		206	156	888	9.25	104.42	
	13:15		206	132	761	7.92	112.34	WELL STARTED MAKING MEDIUM SP OF LIQUIDS
	14:15		237	121	703	29.27	141.61	
	15:15		238	115	671	27.95	169.56	
	16:15		238	110	644	26.85	196.41	
	17:15		235	106	627	26.12	222.53	WELL SI FOR BU
.5	17:45	16.5	335	350 334				
1.0	18:15	8.95	358	371 357				
1.5	18:45	6.17	370	387 370				
2.0	19:15	4.88	378	395 378				
2.5	19:45	4.1	385	402 385				
3	20:15	3.58	391	409 391				
3.5	20:45	3.21	396	414 396				
4	21:15	2.94	401	419 401				
	11-06-75 12	05:15	1.65	436	456	436		
	24	17:15	1.32	454	475	454		

EL PASO NATURAL GAS COMPANY

Memorandum

To: Mr. Richard F. Lemon, Reservoir

From: Production

Date: November 18, 1975

Place: Farmington, NM 87401

Re: Special Test on Chace Oil Company Well

A build-up test was continued for an additional seven (7) days with a pressure recorder attached to the casing and tubing on the Rusty Federal No. 4. The results are listed below.

	Date		Time	Pressure Casing PSIG		Tubing PSIG
48	11-07-75	1.161	1715	*459	480	*459
72	11-08-75	1.108	1715	464	485	464
96	11-09-75	1.081	1715	469	490	469
120	11-10-75	1.065	1715	473	495	473
144	11-11-75	1.054	1715	476	498	476
168	11-12-75	1.046	1715	479	501	479
192	11-13-75	1.040	1715	482	504	482
209.25	11-14-75	1.037	1030	*484	506	*484

*Denotes Dead Weight Pressures

The recorder was removed and the test discontinued.

H. E. McAnally
Senior Well Test Engineer

dsc

cc: Messrs. R. F. Lemon
G. Lippman
R. McCary-Chace
R. Ullrich
Test Data Section--Reservoir
File

SW/SW
Sec 13
T22-R7

1700

CHASE
RUSTY
FED. #4

1738+5178
Chacra A

21' pay

1800

1820+5096
Chacra B

Caliper Curve

Gamma Ray

1872

43' → 10%
9' → 14%

11'

BULK DENSITY

17'

4'

52'

31' → 10%
7' → 14%

COMPENSATION

POROSITY

using the technique described in Ref. 4. (In Ref. 4, Table 5 is used for hydrometer measurements at other than 60 °F; Table 7 allows correction of volume at a given temperature to volume at 60 °F.) Fig. D.2 applies to bubble-point liquids, again using the specific gravity corrected to 60 °F. The bubble-point pressure at 60 °F should be determined in the laboratory.* Fig. D.3 applies to condensate-well fluids and natural gases; knowledge of the gas gravity is required to use Fig. D.3.

T_{pc} and p_{pc} are normally used to estimate the pseudoreduced temperature and pressure:

$$T_{pr} = \frac{T}{T_{pc}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (D.3)$$

and

$$p_{pr} = \frac{p}{p_{pc}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (D.4)$$

where

T = temperature of interest, °R
p = pressure of interest, psia.

Note in Eqs. D.1 through D.4 that temperature must be absolute temperature and pressure must be absolute pressure.

Since many correlations in this appendix use specific gravity or API gravity, it is worthwhile to restate the relationship between those two quantities:

$$°\text{API} = \frac{141.5}{\gamma} - 131.5. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (D.5)$$

In Eq. D.5, the specific gravity, γ, must be corrected to 60 °F and atmospheric pressure.

Figs. D.4 through D.6 are Standing's[5] correlations for properties of mixtures of hydrocarbon gases and liquids. Examples of their use are shown in the figures. Standing's correlations are based mainly on the properties of California crude oils. Cronquist[6] gives correlations that may be useful for Gulf Coast oils.

Fig. D.7 is the well known chart of real gas deviation factor for natural gases. Pseudoreduced properties may be estimated from Eqs. D.1 through D.4.

*If only the value at reservoir temperature is known, Fig. D.5 may be used to estimate the 60 °F value by going vertically upward from the bubble-point pressure to reservoir temperature, horizontally left to 60 °F, and vertically downward to the estimated bubble-point pressure.

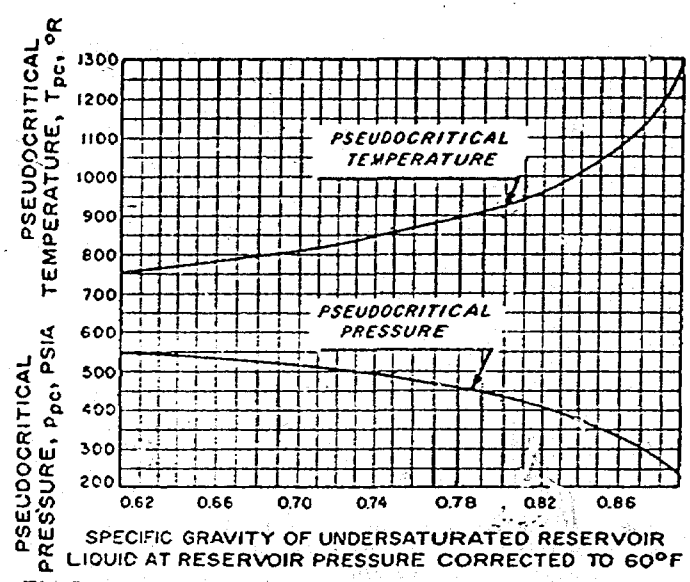


Fig. D.1 Approximate correlation of liquid pseudocritical pressure and temperature with specific gravity. After Trube.[2]

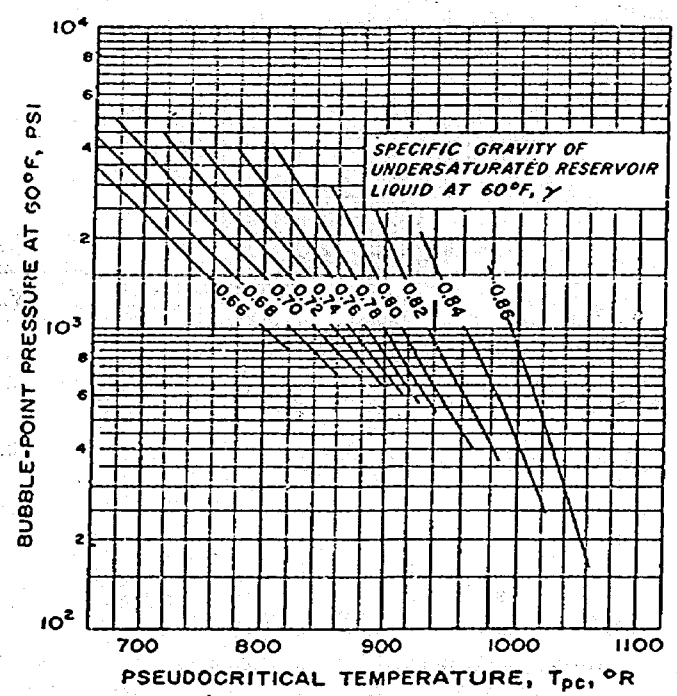


Fig. D.2 Correlation of liquid pseudocritical temperature with specific gravity and bubble point. After Trube.[2]

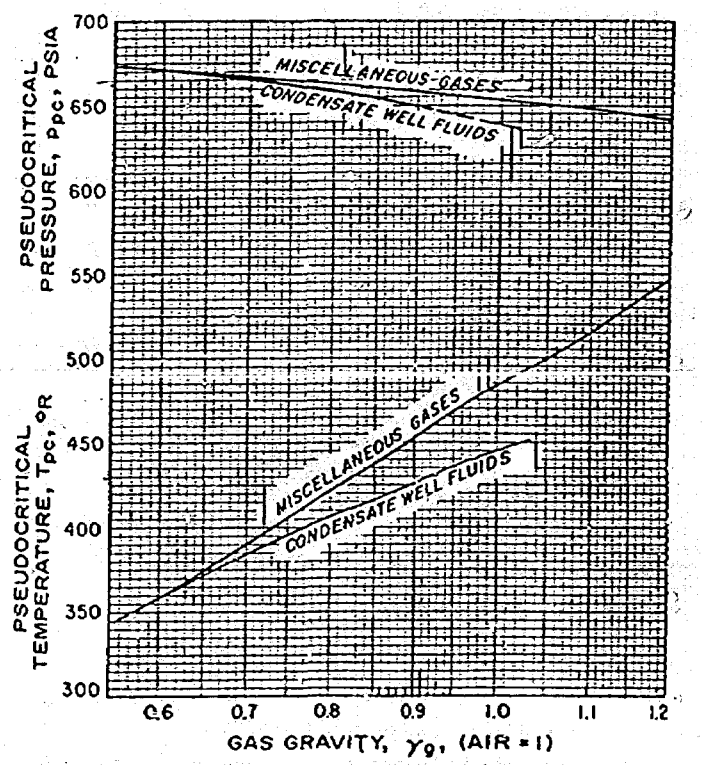


Fig. D.3 Correlation of pseudocritical properties of condensate well fluids and miscellaneous natural gas with fluid gravity. After Brown *et al.*[3]

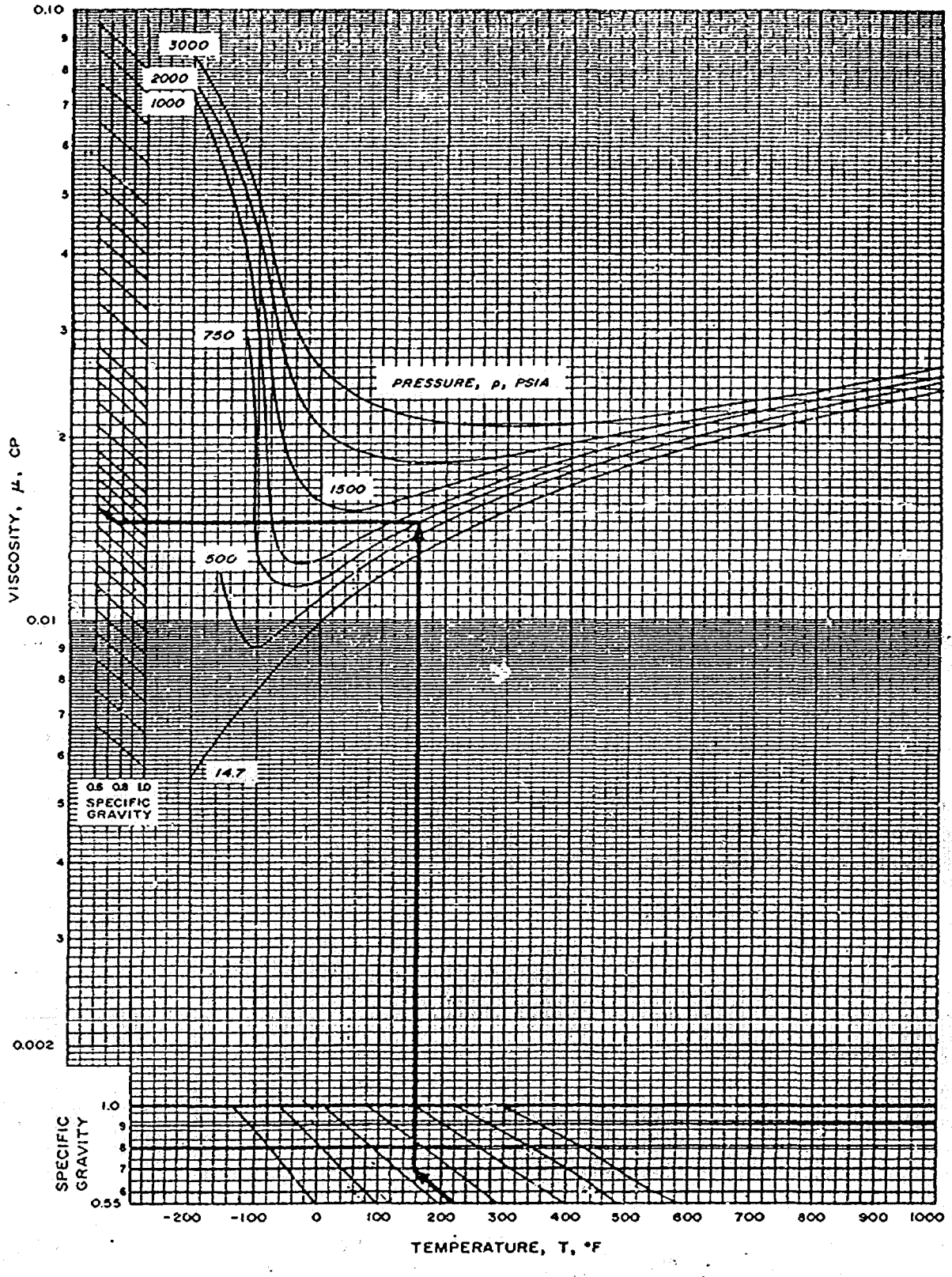


Fig. D.27 Viscosity of hydrocarbon gases.[1]

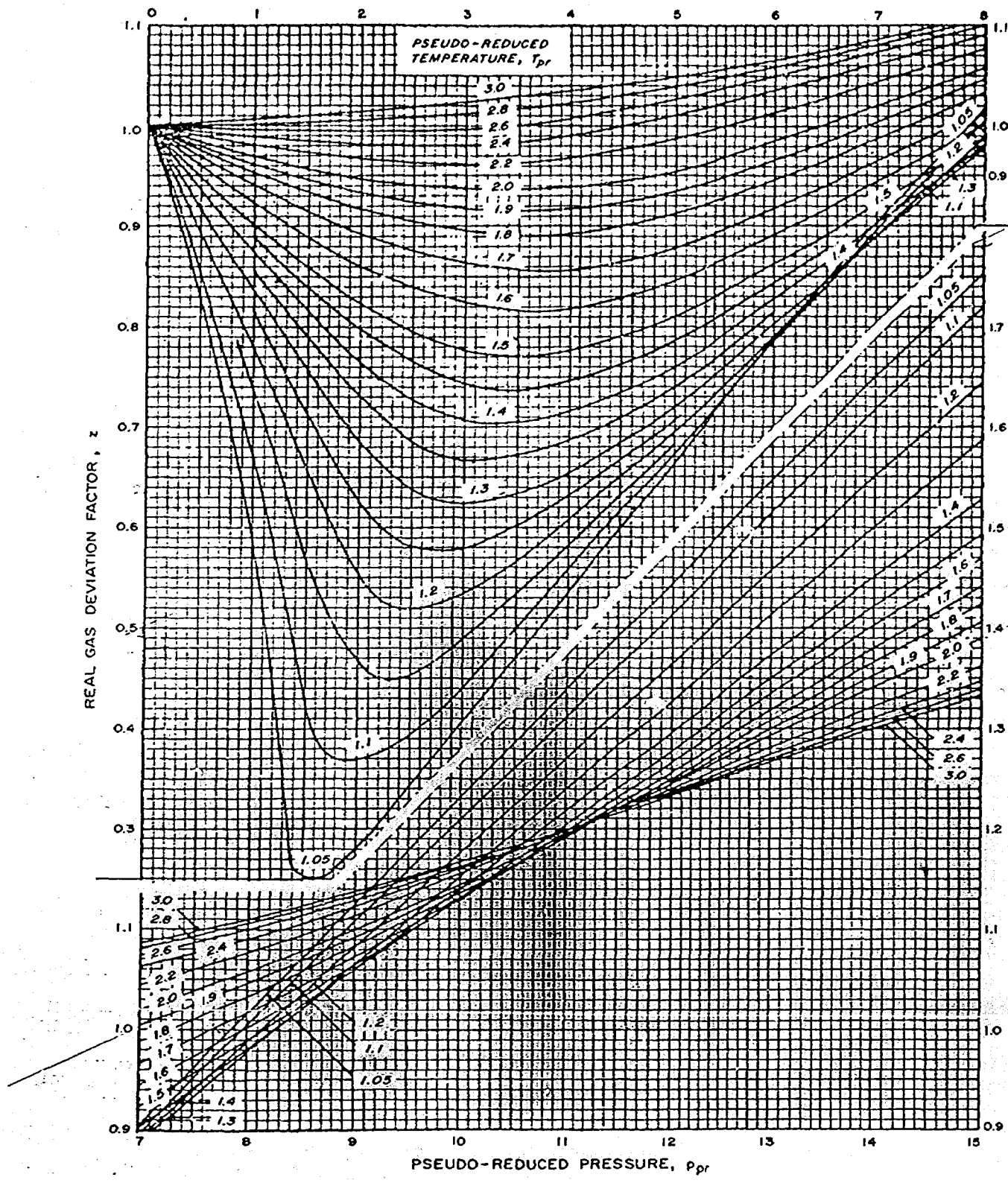


Fig. D.7 Real gas deviation factor for natural gases as a function of pseudoreduced pressure and temperature. After Standing and Katz.[7]

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Dome Navajo 20-22-7 #1

Attached is a copy of the field data for an extended pressure buildup test for this well. Flow rates and bottom hole pressure and times were obtained from this form.

Flowing time, for the purposes of calculating superposition time in the Horner plot was calculated as follows:

cumulative production during the test divided by final flow rate times 24 = t (in hrs.) = 8.72 hrs.

A gas analysis was not available for this well so the average value for gas gravity from eight gas analysis on other Chacra wells was used. Those gas analysis are attached. This average gas gravity of .63 was used in conjuction with Fig. D.3 page 233 of Advances in Well Test Analysis by Robert C. Earlougher Jr. to get pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psia respectively. The average pressure was determined to be 362 psi by averaging the flowing pressure and final shut in pressure.

$$\frac{320 + 404}{2} = 362 \text{ psi}$$

Reservoir temperature was assumed to be the same as that recorded in the pressure buildup test in the Dome Federal 19-22-6 #1. During that test a temperature of 166 degrees F was recorded.

$$T = 166 + 460 = 626 \text{ degrees R}$$

Using this temperature and average pressure pseudo reduced temperature and pseudo reduced pressure were calculated and used with Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr.

$$Ppr = \frac{362}{670} = .54$$

$$Tpr = \frac{626}{367} = 1.7$$

$$z = .97$$

Next gas viscosity was estimated at the average pressure by using Fig. D. 27 page 234 of Advances in Well test Analysis to get

$$\mu = .0121\,cp.$$

Other variables used in the calculation of k, the insitu permeability to gas, are as follows:

q = gas rate in MCF/Day = 101 the last recorded rate before shutting in the well

Δt = shut in time, in hrs., from the field data

h = thickness of pay contributing to production = 100 feet. This number was determined by adding up the permeable zones with porosity greater than 8% as determined from a porosity log.

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: NAVAJO 20-22-7 NO. 1 Page 5 of 8

Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1500' Psig
1-23	Arrived on location							
"	shut-in	08:45				391	392	
"	Tandem insts. @ 1500'	09:40				391	392	412
"	"	10:00				391	392	412
"	Open well, 2"X1/8" CFP	10:00	0	00				
"	"	10:30	0	30				389
"	"	11:00	1	00	119	349	351	377
"	"	11:30	1	30				369
"	"	12:00	2	00	118	342	346	362
"	"	12:30	2	30				357
"	"	13:00	3	00	114	334	334	352
"	"	13:30	3	30				348
"	"	14:00	4	00	111	324	327	343-
"	"	14:30	4	30				340
"	"	15:00	5	00	108	318	318	337
"	"	15:30	5	30				333
"	"	16:00	6	00	106	312	315	331
"	"	16:30	6	30				327
"	"	17:00	7	00	104	305	308	325
"	"	17:30	7	30				322
"	"	18:00	8	00	101	297	299	320
"	Shut in for build up	18:00	0	00				
"	"	18:15	0	15				331
"	"	18:30	0	30				339
"	"	18:45	0	45				345
"	"	19:00	1	00				349
"	"	19:15	1	15				352
"	"	19:30	1	30				354
"	"	20:00	2	00				358
"	"	20:30	2	30				362
"	"	21:00	3	00				364
"	"	22:00	4	00				368
"	"	23:00	5	00				371
1-24	"	00:00	6	00				373
"	"	03:00	9	00				378
"	"	06:00	12	00				382
"	"	12:00	18	00				386
"	"	18:00	24	00				389
1-25	"	06:00	36	00				392
"	"	18:00	48	00				394
1-26	"	18:00	72	00				397

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: NAVAJO 20-22-7 NO. 1 Page 6 of 8

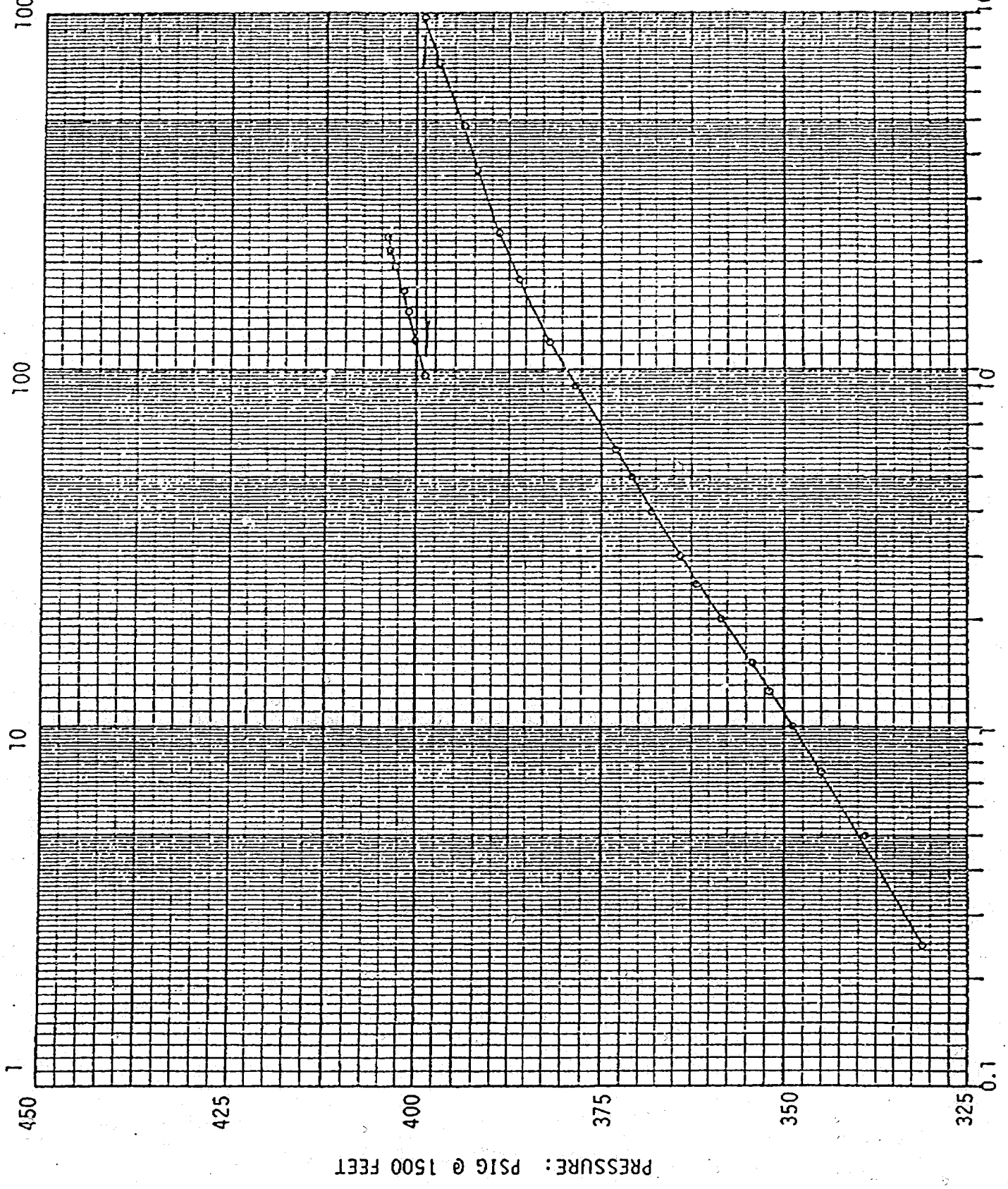
Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Wellhead Pressure Csg	BHP @ 1500' Psig
1-27	Continued shut-in	18:00	96 00				399
1-28	"	18:00	120 00				400
1-29	"	18:00	144 00				401
1-30	"	18:00	168 00				402
1-31	"	18:00	192 00				403
2-1	"	18:00	216 00				403.5
2-2	"	13:30	235 30				404
"	Gradient Traverse	14:00	236 00		387		404

EFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION
Well NAVAJO 20-22-7 NO. 1
Field RUSTY CHACRA
Formation CHACRA
County SANDOVAL
State NEW MEXICO



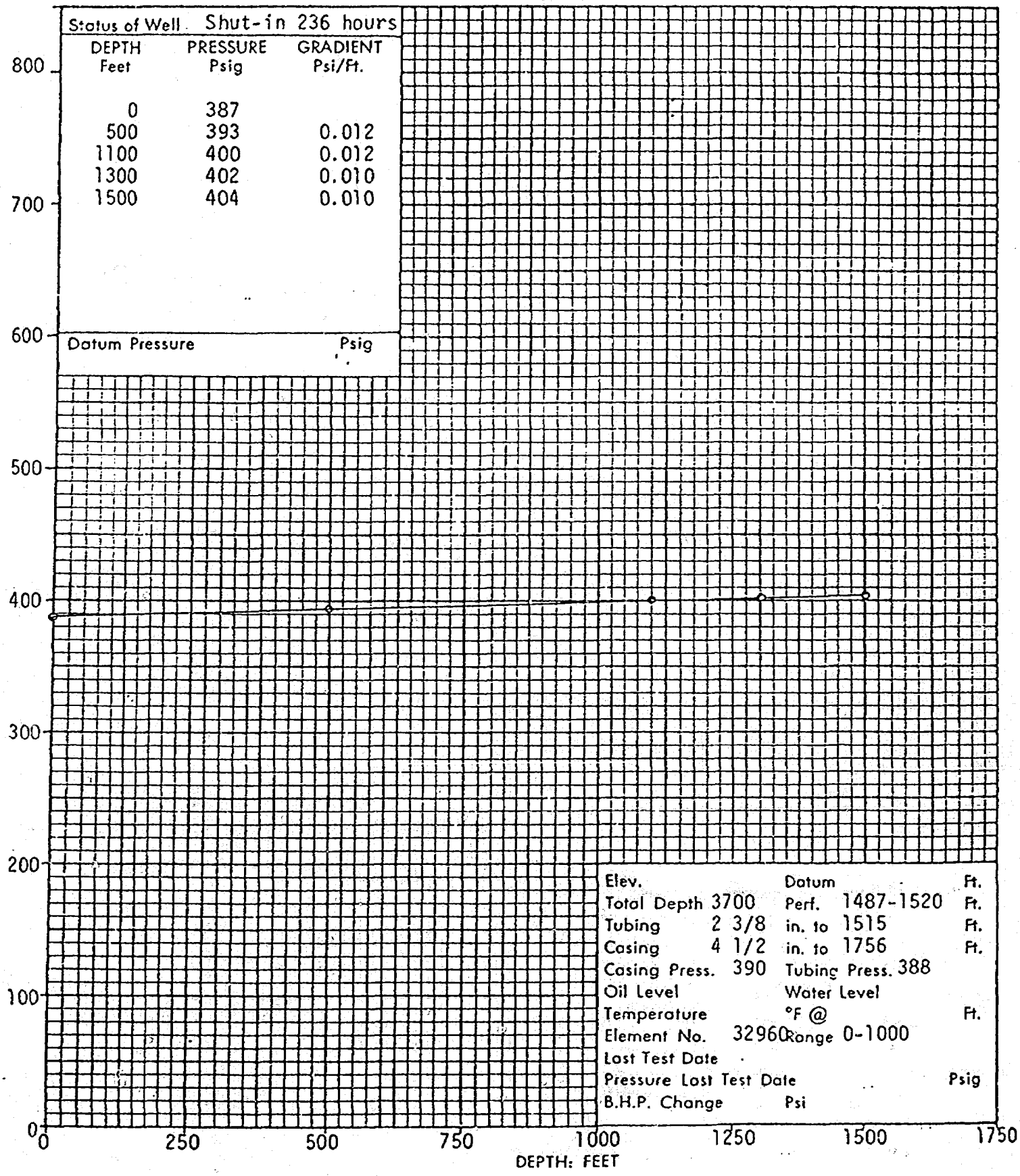
EFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Lease NAVAJO 20-22-7 Well No. 1
Field RUSTY CHACRA County SANDOVAL State NEW MEXICO
Formation CHACRA Test Date FEBRUARY 2, 1981

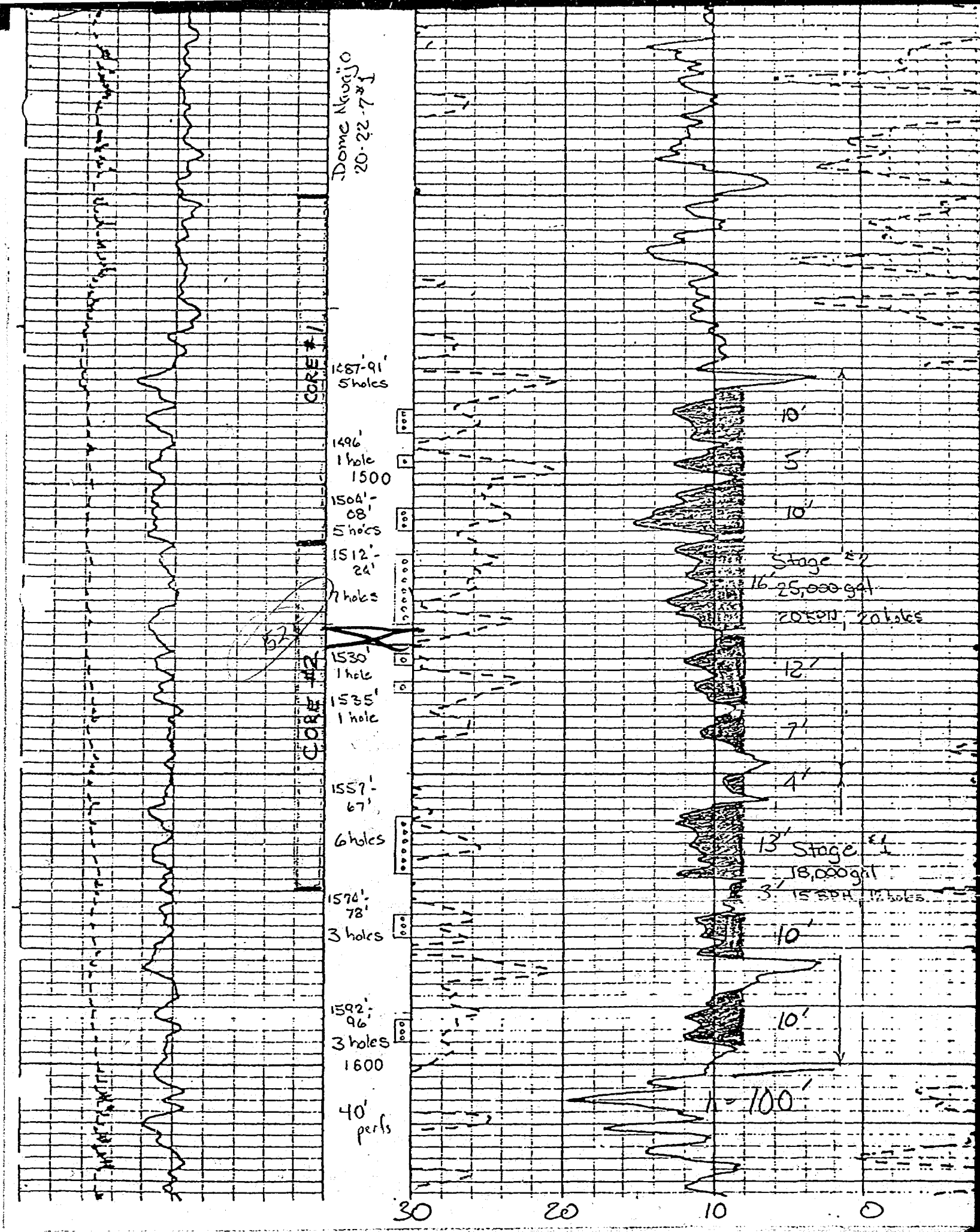
Status of Well: Shut-in 236 hours

DEPTH Feet	PRESSURE Psig	GRADIENT Psi/Ft.
0	387	
500	393	0.012
1100	400	0.012
1300	402	0.010
1500	404	0.010

Datum Pressure Psig



Elev.		Datum	Ft.
Total Depth	3700	Perf.	1487-1520 Ft.
Tubing	2 3/8	in. to	1515 Ft.
Casing	4 1/2	in. to	1756 Ft.
Casing Press.	390	Tubing Press.	388
Oil Level		Water Level	
Temperature		°F @	Ft.
Element No.	32960	Range	0-1000
Lost Test Date			
Pressure Lost Test Date			Psig
B.H.P. Change		Psi	


Dome Navajo
20-22-7*1
CORE #1
CORE #2
1487'-91'
5 holes
1496'
1 hole
1500
1504'-08'
5 holes
1512'-24'
7 holes
1530'
1 hole
1535'
1 hole
1557'-67'
6 holes
1574'-78'
3 holes
1592'-96'
3 holes
1600
40' perfs
10'
5'
10'
Stage #1
16' 25,000 gal
20-40 SD, 20 holes
12'
7'
4'
13'
Stage #2
18,000 gal
3' 15-30 SD, 12 holes
10'
10'
1" = 100'
30
20
10
0

K&E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

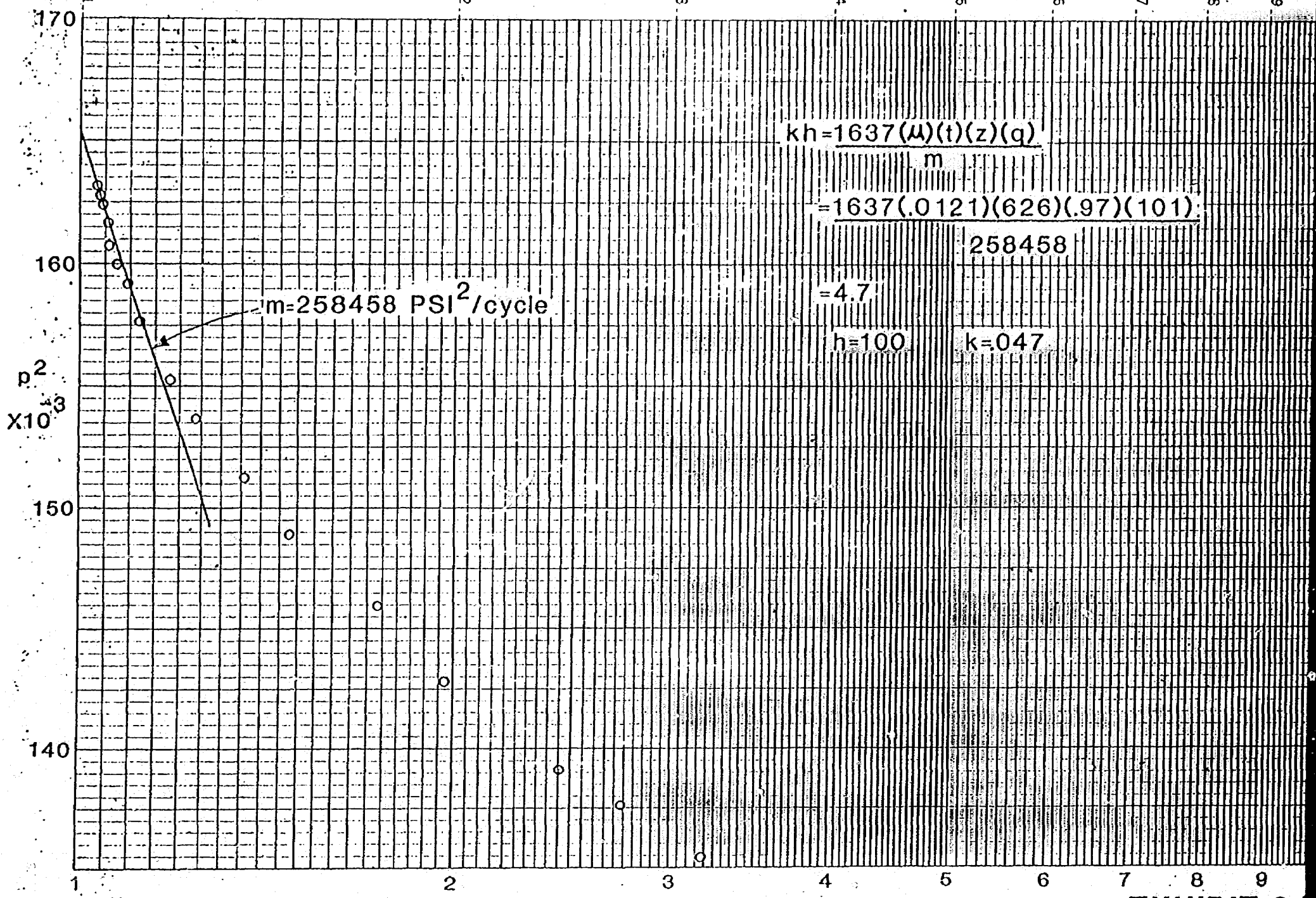


EXHIBIT 9A

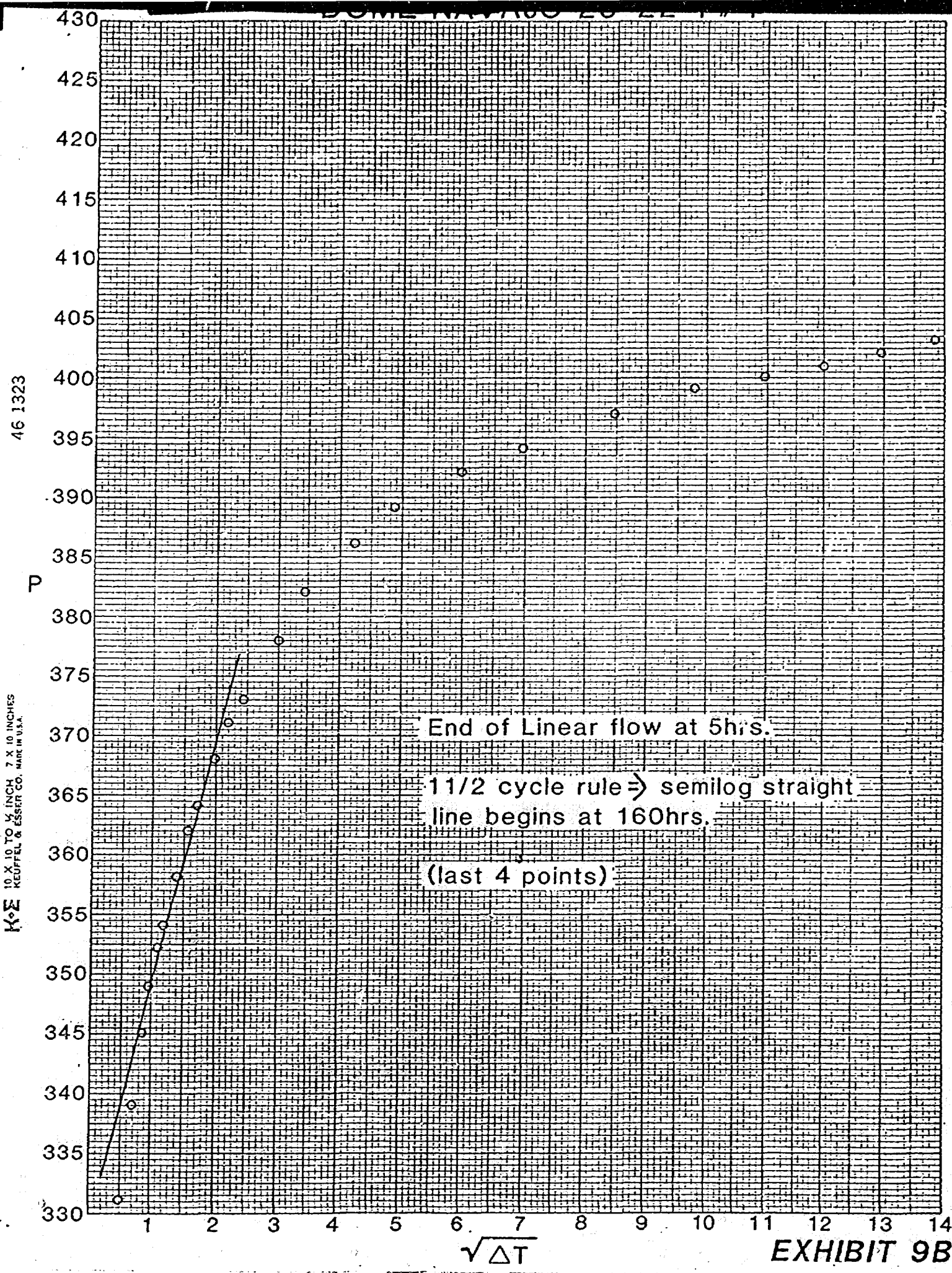

46 1323
K+E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.
P
430
425
420
415
410
405
400
395
390
385
380
375
370
365
360
355
350
345
340
335
330
1
2
3
4
5
6
7
8
9
10
11
12
13
14
√ΔT
End of Linear flow at 5hrs.
1 1/2 cycle rule ⇒ semilog straight line begins at 160hrs.
(last 4 points)

EXHIBIT 9B

RECEIVED
JUN 1979

Petroleum Reservoir Engineering
DALLAS, TEXAS

JUN 25 1979
DOME DENVER

File 9106 GA-735

Company DOME PETROLEUM CORPORATION Formation UPPER CHACRA

Well DOME FEDERAL 30-22-6 NO. 1 County

Field State

Chromatographic Gas Analysis

COMPONENT	MOL PER CENT	G. P. M.	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Carbon Dioxide	.05				
Nitrogen	2.00				
Methane	88.07				
Ethane	6.11	1.534			
Propane	2.46	.673			
iso-Butane	.39	.127			
n-Butane	.48	.150			
iso-Pentane	.17	.062			
n-Pentane	.10	.036			
Hexanes	.08	.032			
Heptanes plus	.09	.041			
	100.00	2.655			

Calculated gas gravity (air=1.000) = .638

Calculated gross heating value = 1104 BTU per cubic foot of dry gas at 14.65 psia.

Collected at 100 psig and 110° F.

SAMPLE DETAILS

Type Gas

Client Sample No. Cylinder No.

Date Sampled Temperature °F

Sampling Pressure psig Sampled By

These analyses, opinions or interpretations are based on observations and material supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations as to the productivity, proper operation, or profitableness of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

17, Fixed Chlor. Not Run 7/17

1

SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. WE23734

Sample From Chaco Oil Co. Date Secured 4-6-76

Sample Marked Navajo Federal 1-X Secured By Don Norton

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	1.57		
Methane	88.92		
Ethane	5.32		
Propane	2.43	.6670	
I-Butane	.39	.1272	
N-Butane	.47	.1477	
I-Pentane	.16	.0584	
N-Pentane	.09	.0325	
Hexane	.10	.0435	
TOTALS	100.00	1.076	

Run By Hazen Checked By James

Remarks

R L Ahrens
H.L. Holder
R. Ullrich
R.E.Johnson
R.B. Herr
M.E. Blakely
R. F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 355 @ 57° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1105

Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercaptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .633

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 23 T. 22 N. R. 7 W.

County
Sandoval

State
N.M.

Formation
La Ventana

Bomb Pressure
100 #

EL PASO NATURAL GAS COMPANY
SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF23732

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Rusty Navajo #2 Secured By Jess Goodwin

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	1.43		
Methane	88.94		
Ethane	5.83		
Propane	2.47	.6739	
I-Butane	.49	.1394	
N-Butane	.43	.1509	
I-Pentane	.17	.0620	
N-Pentane	.11	.0397	
Hexane	.07	.0304	
TOTALS	100.00	1.092	

Run By Hazen Checked By James

Remarks
R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.E. Herr
M.E. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Habe
File.

Source 3187 @ 55° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1108

Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercaptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .633

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 23 T. 22 N. 7 R. W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

EL PASO NATURAL GAS COMPANY
SAN JUAN LABORATORY

ONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 7-11-75 Analysis No. VF 27475

Sample From Chace Oil Company Date Secured 7-9-75

Sample Marked #1 Gulf Federal Secured By C. C. Kennedy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
arbon Dioxide	0.07		
ydrogen Sulfide	Not Run		
trogen	4.58		
ethane	88.28		
thane	4.50		
ropane	1.66	0.456	
-Butane	0.39	0.127	
-Butane	0.28	0.088	
-Pentane	0.13	0.047	
-Pentane	0.06	0.022	
exane	0.05	0.022	
TOTALS	100.00	0.762	

n By Ross Checked By James

cc: R L Ahrens
H. L. Holder
R. Ullrich
R. E. Johnson
R. B. Herr
M. E. Blakely, Jr.
R. F. Lemon
J. E. Ashworth
Don Adams
File

C. C. Kennedy
4949 San Pedro, N.E.
Albuquerque, New Mexico 87109

HEATING VALUE
B.T.U. PER CU. FT.
Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition
Calorimeter 1045

SULPHUR CONTENT
GRAINS PER 100 CU. FT.
14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide
Mercaptans

SPECIFIC GRAVITY
14.696 lbs./sq. in., 60° F.
Calculated from % Composition 0.626
Calculated from % Liquid

VAPOR PRESSURE
PSIA at 100° F.
Calculated from Mole %

Column/s Used: AE & MS
Calculation By: NGPA
Carbon Dioxide: NGPA
Hydrogen Sulfide: Cd Cl2

LOCATION AND WELL DATA
Sec. T. N. R. W.
County
State
Formation
Bomb Pressure

SAN JUAN LABORATORY

ACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF23733

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Gulf Federal #3 Secured By Rodger Hardy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	4.02		
Methane	38.32		
Ethane	4.28		
Propane	1.83	.5023	
i-Butane	.43	.1402	
N-Butane	.32	.1006	
i-Pentane	.13	.0474	
N-Pentane	.07	.0252	
Hexane	.05	.0217	
TOTALS	100.00	.838	

n By Hazen Checked By James

emarks

R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.B. Kerr
M.E. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 315 @ 56° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1054

Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercaptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .626

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 13 T. 22 N. R. 7 W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

EL PASO NATURAL GAS COMPANY

SAN JUAN LABORATORY

CTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 10-16-75 Analysis No. VF 27943

Sample From Chace Oil Company Date Secured 10-13-75 @ 1615 hours

Sample Marked Rusty Federal #3 Secured By McAnally

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
arbon Dioxide	0.08		
ydrogen Sulfide			
itrogen	1.56		
ethane	88.48		
thane	6.22		
ropane	2.21	0.607	
-Butane	0.36	0.117	
Butane	0.42	0.132	
-Pentane	0.16	0.058	
N-Pentane	0.10	0.036	
exane	0.41	0.178	
TOTALS	100.00	1.128	

n By Ross Checked By James

omarks

R L Ahrens
H. L. Holder
R. Ullrich
R. E. Johnson
H. McAnally - 3
File
R. B. Herr
M. E. Blakely, Jr.
R. F. Lemon
Don Adams
File

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1116

Colorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide

Mercaptans

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition 0.640

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used	AE & MS
Calculation By	NGPA
Carbon Dioxide	NGPA
Hydrogen Sulfide	Cd Cl₂

LOCATION AND WELL DATA

Sec. 14 T. 22 N. R. 7 W.
County Sandoval
State New Mexico
Formation La Ventana - Rusty Pond
Bomb Pressure 978 @ 60°F

in general P.D.C. & Surg.
enclose from mail room
(2 3C) vc.

8 DRY MODE METER RUSTY-FED#3-NEW-WELL 1976

Miller
Fuller

COMPONENT	MOL%	GPM	SP GR	BTU
N2	1.22	0.000	0.012	0.
CH4	89.53	0.000	0.496	906.
C2	5.76	0.000	0.060	102.
CO2	0.11	0.000	0.002	0.
C3	2.26	0.623	0.034	57.
IC4	0.35	0.116	0.007	12.
NC4	0.41	0.130	0.008	13.
IC5	0.14	0.051	0.003	6.
NC5	0.07	0.026	0.002	3.
C6+	0.15	0.065	0.005	8.
	100.00	1.009	0.630	1109.

BASE MOL% 99.68

Northwest Pipeline Corporation
MAR 22 1976
Production Department

SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF23733

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Gulf Federal #3 Secured By Rodger Hardy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	4.02		
Methane	38.32		
Ethane	4.28		
Propane	1.33	.5023	
I-Butane	.43	.1602	
N-Butane	.32	.1006	
I-Pentane	.13	.0474	
N-Pentane	.07	.0252	
Hexane	.05	.0217	
TOTALS	100.00	.338	

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1054

Colorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercoptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .626

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

n By Hazen Checked By James

marks

R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.B. Kerr
M.E. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 315 @ 56° F

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 13 T. 22 N. R. 7 W.

County
Sandoval

State
N.M.

Formation
La Ventana

Bomb Pressure
100 #

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Dome Federal 19-22-6 #1

Attached is a copy of the field data for an extended pressure buildup test for this well. Flow rates, bottom hole pressure, bottom hole temperature, and times were taken from this form.

Flowing time for the purpose of calculating superposition time in the Horner plot was calculated as follows:

cumulative production during the test divided by final flow rate times 24 = t (in hrs.) = 10.26 hrs.

A gas analysis was not available for this well so the average value for gas gravity from eight gas samples from other Chacra wells was used. Those gas analysis are attached. This average gas gravity of .63 was used in conjunction with Fig. D. 3 page 233 of Advances in Well Test Analysis by Robert C. Earlougher Jr. to get pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psia respectively. The average pressure was determined to be 371 psi by averaging the flowing pressure and the final shut in pressure.

$$\frac{306 + 437}{2} = 371 \text{ psi}$$

Reservoir temperature was taken from the field data and converted to degrees R

166 degrees F + 460 = 626 degrees R

Using this temperature and average pressure the pseudo reduced temperature and pseudo reduced pressure were calculated and

used with Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr.

$$Ppr = \frac{371}{670} = .55$$

$$Tpr = \frac{626}{367} = 1.7$$

$$z = .97$$

Next gas viscosity was estimated at the average pressure by using Fig. D.27 page 234 of Advances in Well Test Analysis to get μ = .0121 cp.

Other variables used in the calculation of k, the insitu permeability to gas, are as follows:

q = gas rate in MCF/Day = 275 the last recorded rate before shutting the well in.

Δt = shut in time, in hrs., from the field data

h = thickness of pay contributing to production = 105 feet. This number was determined by adding up the permeable zones with porosity greater than 8% as determined by a porosity log.

K•Σ SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME/FED. 19-22-6#1

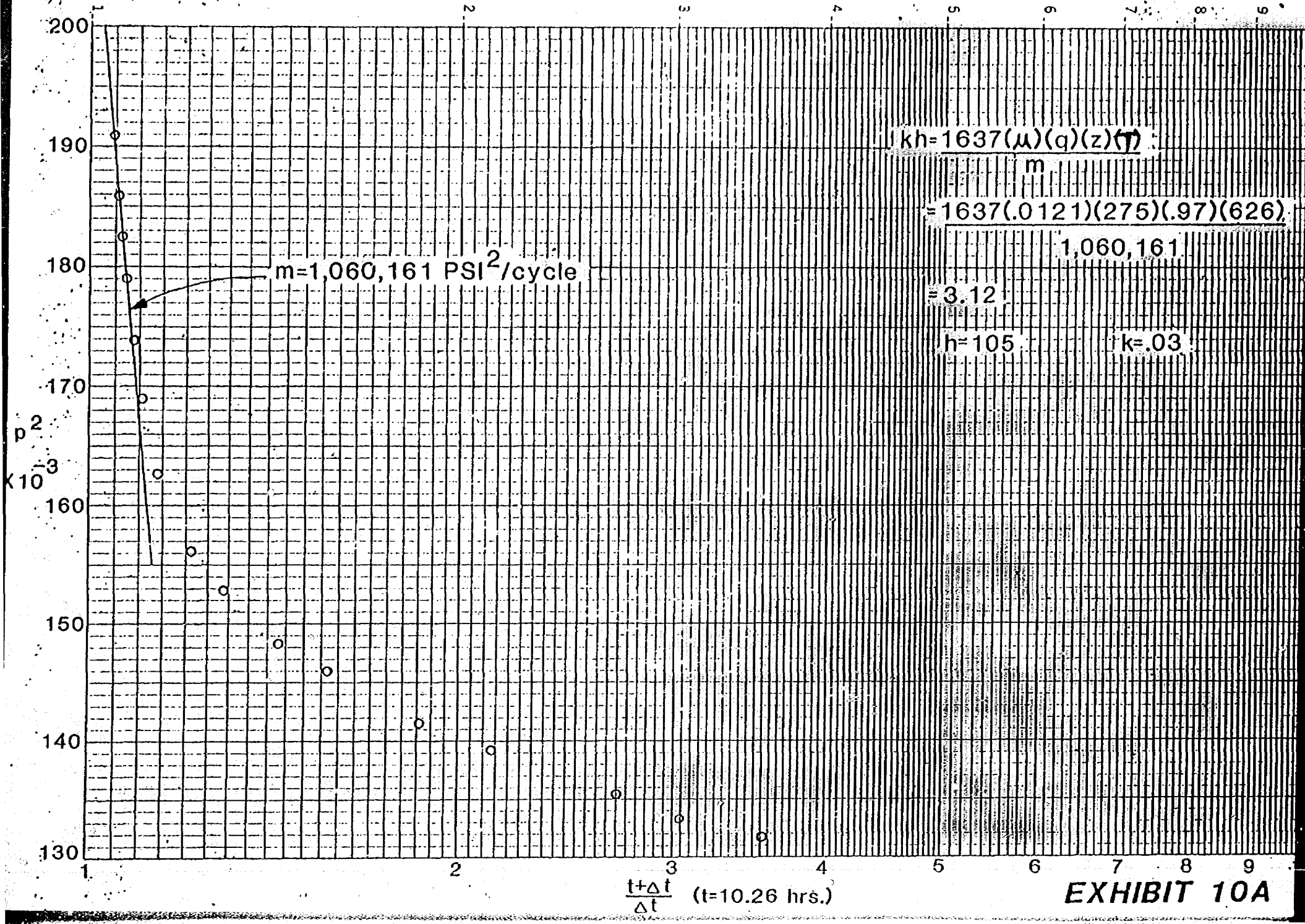


EXHIBIT 10A

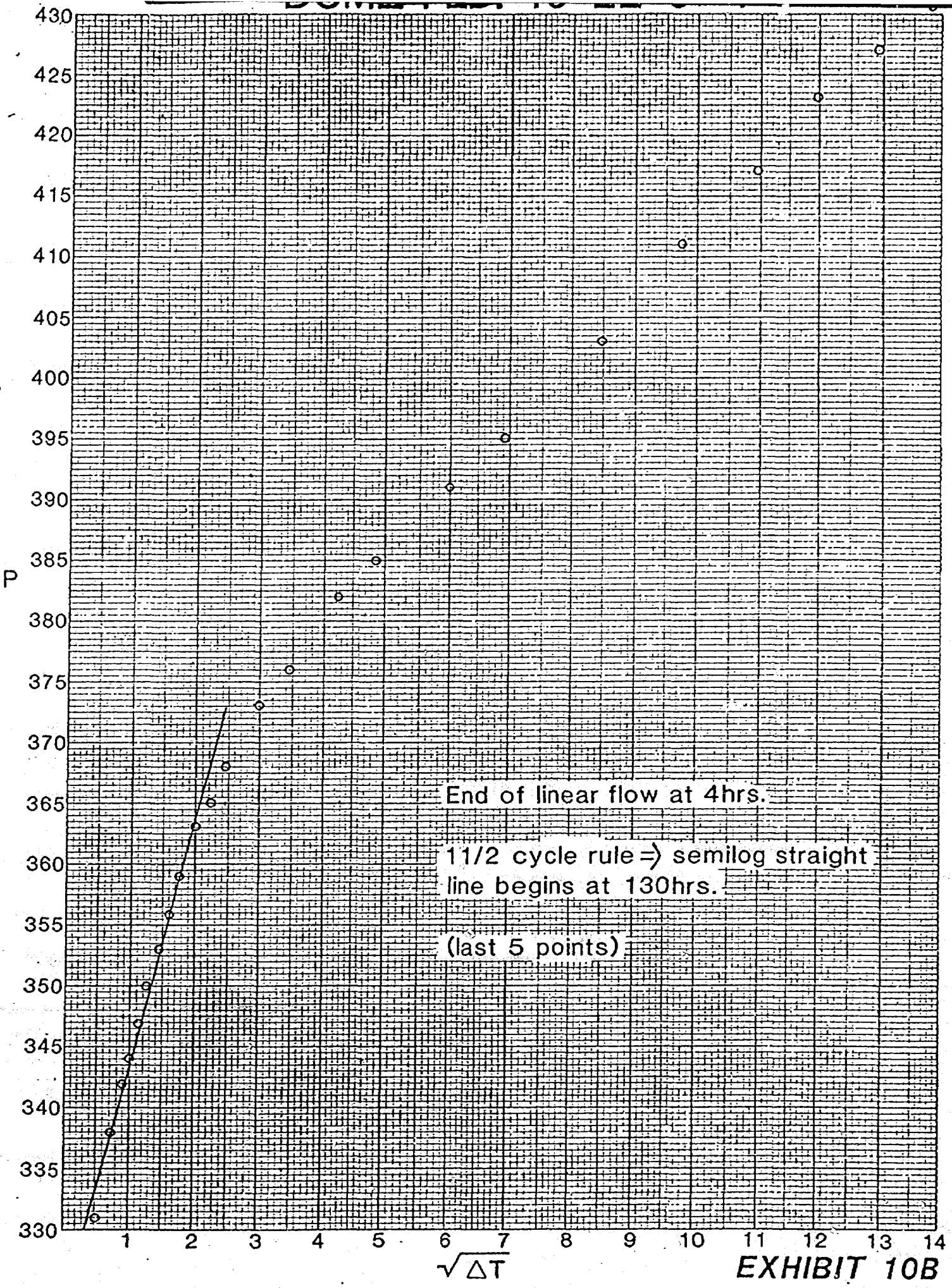

46 1323
K&E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.
P
430
425
420
415
410
405
400
395
390
385
380
375
370
365
360
355
350
345
340
335
330
1
2
3
4
5
6
7
8
9
10
11
12
13
14
√ΔT
End of linear flow at 4hrs.
1 1/2 cycle rule ⇒ semilog straight line begins at 130hrs.
(last 5 points)

EXHIBIT 10B

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: FEDERAL NO. 19-22-6 No. 1 Page 1 of 8

Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg Csg	BHP @ 1900' Psig
1-23	Arrived on location, shut-in	10:00				
"	Tandem instruments @ 1900'	11:08				403
"	"	11:30				403
"	Open on 1/4" orifice plate,					
"	producing thru casing	11:30	0 00			
"	"	12:00	0 30			356
"	"	12:30	1 00	416	Vac. 296	347
"	"	13:00	1 30			342
"	"	13:30	2 00	392	Vac. 278	336
"	"	14:00	2 30			332
"	"	14:30	3 00	375	Vac. 266	328
"	"	15:00	3 30			326
"	"	15:30	4 00	360	Vac. 255	323
"	"	16:00	4 30			321
"	"	16:30	5 00	348	246	319
"	"	17:00	5 30			316
"	"	17:30	6 00	334	236	314
"	"	18:00	6 30			311
"	"	18:30	7 00	321	226	308
"	"	19:00	7 30			307
"	"	19:30	8 00	275	192	306
"	Shut-in for build up	19:30	0 00			
"	"	19:45	0 15			331
"	"	20:00	0 30			338
"	"	20:15	0 45			342
"	"	20:30	1 00			344
"	"	20:45	1 15			347
"	"	21:00	1 30			350
"	"	21:30	2 00			353
"	"	22:00	2 30			356
"	"	22:30	3 00			359
"	"	23:30	4 00			363
1-24	"	00:30	5 00			365
"	"	01:30	6 00			368
"	"	04:30	9 00			373
"	"	07:30	12 00			376
"	"	13:30	18 00			382
"	"	19:30	24 00			385

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: FEDERAL NO. 19-22-6 No. 1 Page 2 of 8

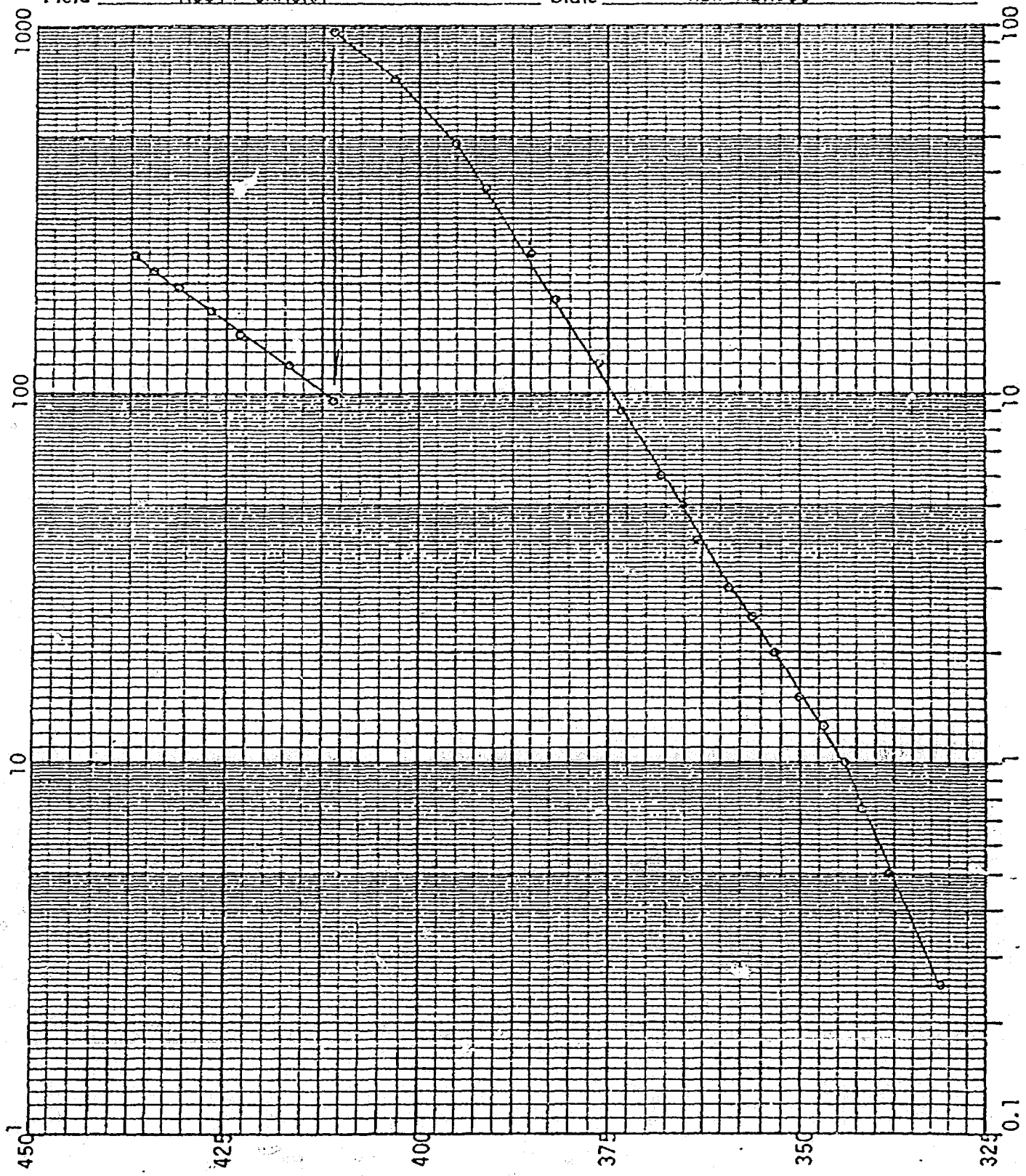
Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1900' Psig
1-25	Continued shut-in	07:30	36	00				391
"	"	19:30	48	00				395
1-26	"	19:30	72	00				403
1-27	"	19:30	96	00				411
1-28	"	19:30	120	00				417
1-29	"	19:30	144	00				423
1-30	"	19:30	168	00				427
1-31	"	19:30	192	00				431
2-1	"	19:30	216	00				434
2-2	Pull instrument	15:00	235	30		Nil	378	437
"	Gradient Traverse	15:30	236	00				437

TEFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Formation CHACRA
Well FEDERAL 19-22-6 NO. 1 County SANDOVAL
Field RUSTY CHACRA State NEW MEXICO



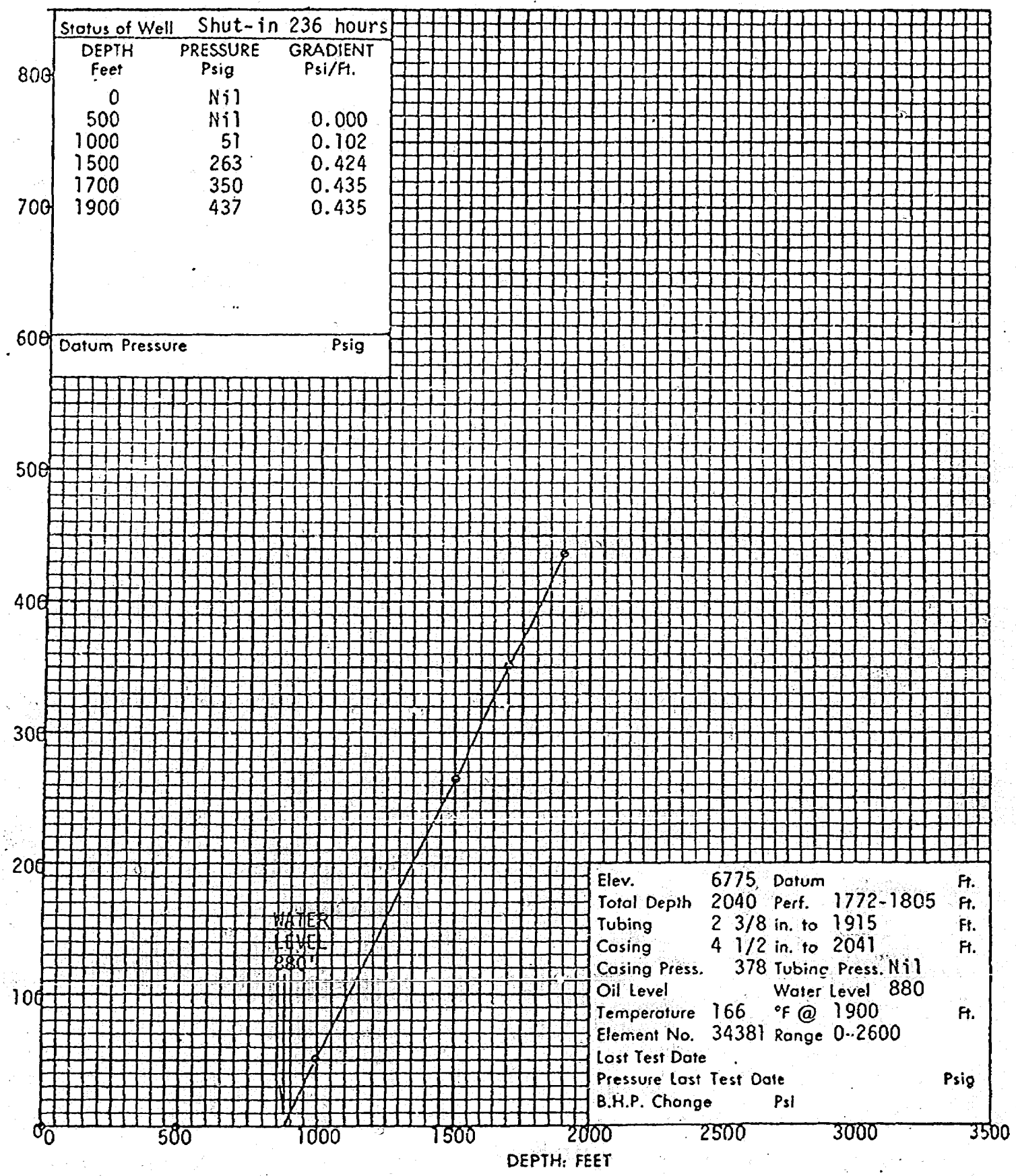
EFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Lease FEDERAL 19-22-6 Well No. 1
Field RUSTY CHACRA County SANDOVAL State NEW MEXICO
Formation CHACRA Test Date FEBRUARY 2, 1981

Status of Well Shut-in 236 hours

DEPTH Feet	PRESSURE Psig	GRADIENT Psi/Ft.
0	Nil	
500	Nil	0.000
1000	51	0.102
1500	263	0.424
1700	350	0.435
1900	437	0.435

Datum Pressure Psig



Elev.	6775	Datum	Ft.
Total Depth	2040	Perf. 1772-1805	Ft.
Tubing	2 3/8	in. to 1915	Ft.
Casing	4 1/2	in. to 2041	Ft.
Casing Press.	378	Tubing Press. Nil	
Oil Level		Water Level 880	
Temperature	166	°F @ 1900	Ft.
Element No.	34381	Range 0--2600	
Lost Test Date			
Pressure Last Test Date			Psig
B.H.P. Change		Psi	

Dome
Fed.
19-22-6
#1

Perf. 1698-1700
2 holes

Perf 1708
1 hole

Perf.
1714-22
5 holes

Perf.
1724-
36 7 holes

Perf
1738-44
4 holes

Perf.
1772-79
8 holes

Perf.
1794-96
3 holes

Perf.
1804-05
2 holes

41 perfs

2'
6'
44'
30'
6'
6'
10'

FOAM FRAC STAGE 2
FOAM FRAC STAGE 1

RECEIVED
JUN 22 1981
OIL CONSERVATION DIVISION
SANTA FE

EXHIBITS FOR PROPOSED

TIGHT GAS FORMATION AREA

CHACRA FORMATION

RUSTY CHACRA AREA

SANDOVAL COUNTY, NEW MEXICO

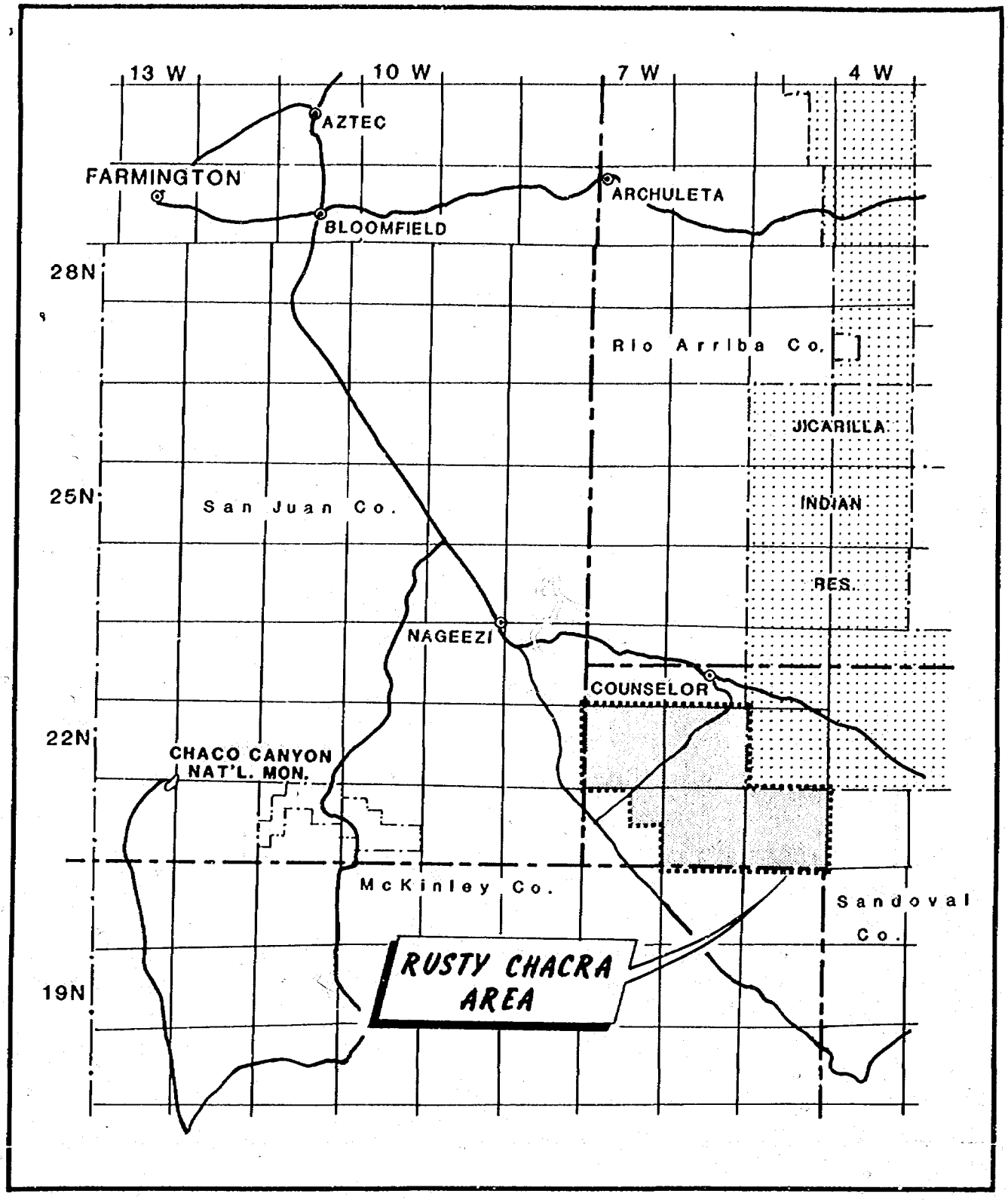
May, 1981

Dome Petroleum Corp.
2900 Dome Tower
1625 Broadway
Denver, Colorado 80202

SUMMARY OF EXHIBITS

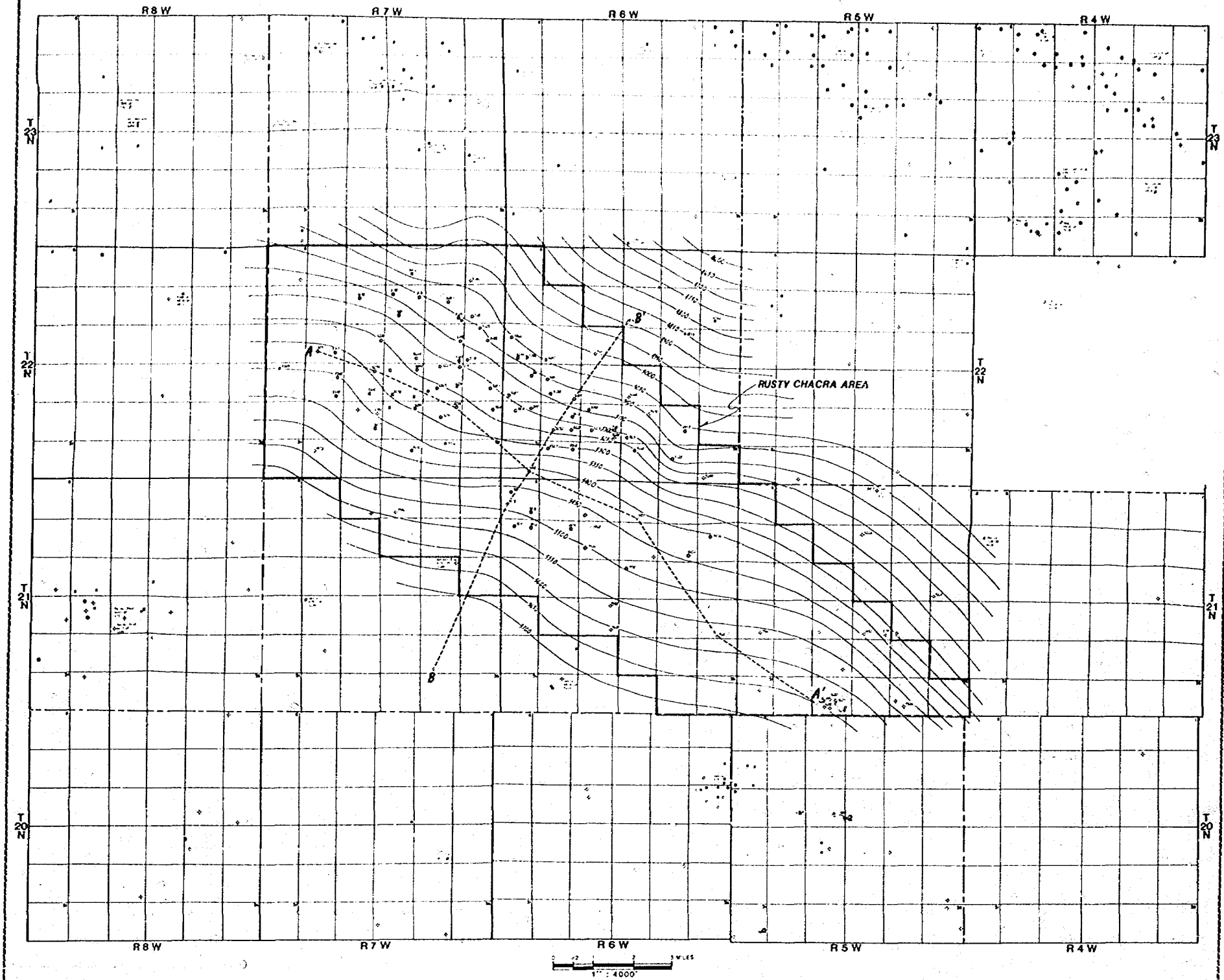
RUSTY CHACRA AREA

Exhibit No.	Title or Subject
1	Index map showing relative location of application area
2	Structure Map
3	Summary of Geology
4	Cross Section
5	Type Log
6	Summary of Reservoir data
7	Summary of Pertinent Data by well
8	Pressure Build-up analysis Chase Rusty Federal #4 Horner plot and P vs $\sqrt{\Delta t}$ plot
9	Pressure Build-up analysis Dome Navajo 20-22-7 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
10	Pressure Build-up analysis Dome Federal 19-22-6 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
11	Summary of wells with measured unstimulated rates
12	Typical casing design



INDEX MAP OF NORTH WESTERN NEW MEXICO
SHOWING RELATIVE LOCATION OF
RUSTY CHACRA AREA

Exhibit 1



DOME PETROLEUM CORP.

RUSTY CHACRA AREA

SANDOVAL CO., NEW MEXICO

Structure Contours on Top "Chacra" Zone

Proposed Tight Gas Formation Area

Exhibit #2

DATE 5-80 | GEOLOGY BY M.J.FUCHS | FILE NO 823

Rusty Chacra Area Tight Gas Hearing

Exhibit #3

Summary of Geology

The Rusty Chacra Area is located six miles south of the town of Counselor in Sandoval Co., New Mexico. Geologically, the area is located on the Chaco Slope of the southern San Juan Basin. Gas production is from a buildup of transitional shaly sands and siltstones which are interpreted to be of a prodelta low-energy origin. This productive zone which is called the "Chacra" is the time-stratigraphic equivalent of the upper Unnamed Tongue of the Cliffhouse beach sandstone. Structural dip to the north-east of about 100 feet per mile is of little consequence as this is a stratigraphic trap. The sandstones are gray to light gray, fine grained, silty, shaly, and slightly to moderately calcitic.

The fine grained and clay filled nature of the sands results in low porosity and permeability and commercial production when obtained is only achieved through extensive fracturing and reservoir treatment.

SUMMARY OF EXHIBITS

RUSTY CHACRA AREA

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11	Summary of wells with measured unstimulated rates
12	Typical casing design

ENGINEERING SUMMARY
CHACRA FORMATION
RUSTY CHACRA AREA

Exhibits 6 through 12 will help illustrate that the Chacra sandstone meets the requirements to qualify for tight gas formation incentive pricing. The exhibits will show: (1) the average in-situ permeability is less than 0.10 md; (2) the average pre-stimulation stabilized flow rate is less than 18 CFR 271.705 guidelines; (3) oil production is less than 5 BOPD; and (4) any fresh water zones are protected from contamination.

EXHIBIT NO. 6 - Summary of Reservoir Data

This table shows typical reservoir data for the Chacra sandstone within the application area. This information shows that the criteria for permeability, unstimulated flow rate, and crude oil production are all met. The average depth to the top of the Chacra formation of 1658' is derived from the data presented in exhibit 7. The calculation of the average permeability of 0.07 md is detailed in exhibits 8, 9, and 10 while the average unstimulated rate of gas to small to measure is derived from exhibit 11.

EXHIBIT 7 - Summary of Pertinent Data by Well

These tables show all of the Chacra sandstone wells within the application area. Averages of the depth to the top of the Chacra as well as the average three hour potential test after fracture stimulation were shown in exhibit 6. The tables also give well locations, completion interval, spud date and current well status. As shown, most of the wells in this area are shut-in gas wells which are waiting on pipeline connections.

EXHIBIT 8, 9, and 10 - Pressure Build-up Analysis

These exhibits show how in-situ permeability to gas was calculated for each of three Chacra wells which had extended pressure build-ups. For each of the three wells a Horner plot of pressure squared vs. $(t + \Delta t)/\Delta t$ is shown as well as a plot of pressure vs. $\sqrt{\Delta t}$. The straight line portion of the Horner plot is used to calculate permeability. Early data is affected by wellbore storage and linear flow in fractures induced by hydraulic fracture stimulation treatment. The second plot of pressure vs. $\sqrt{\Delta t}$ helps to show which part of the Horner plot should be used in the calculation of permeability and which part is still affected by linear flow and storage. The results of these three extended pressure surveys are as follows:

WELL	IN-SITU PERMEABILITY
Chase Rusty Federal #4	0.13 md
Dome Navajo 20-22-7 #1	0.05 md
Dome Federal 19-22-6 #1	0.04 md
Average	0.07 md

EXHIBIT 11 - Summary of Wells with Measured Unstimulated Rates

This table shows the Chacra completions in which unstimulated rates were reported after swabbing the well down prior to fracture treatment. The standard procedure in this area has been to stimulate the well immediately after perforating by hydraulic fracturing methods. Due to this procedure unsimulated rates were

generally not reported except for the wells shown in this table. This table shows that in all cases unstimulated rates were below the guidelines given in 18 CFR 271.705 which specifies for 1658' (the average depth to the top of the Chacra) a maximum unstimulated rate of 59 MCFD. The average for the wells shown in this exhibit is a rate too small to measure and represents the expected unstimulated rate for this formation. It should also be noted that none of these wells have produced any crude oil before or after stimulation.

EXHIBIT 12 - Typical Casing Design

This exhibit shows how any potential fresh water zones would be protected by surface casing and production casing which are both cemented to surface.

KFT:jp

SUMMARY OF RESERVOIR DATA

RUSTY CHACRA AREA

Exhibit 6

Reservoir Temperature	160 degrees F
Average Reservoir Pressure	460 psia
Average Depth to Top of Chacra	1658'
Average Porosity	11%
Average Permeability	0.07 md
Average Unstimulated Flow Rate	TSTM
Average 3 hr. Potential Test Rate	594 MCFD
Crude Oil Production	None

EXHIBIT 7
Page 1

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Cole	Alamos Canyon #1	SW	4	21N	6W	1/11/81*	1370	1396-1436	275	SIGW
Cole	Alamos Canyon #6	SE	6	21N	6W	8/18/80*	1304	1304-1343	1025	SIGW
Cole	Alamos Canyon #9	NW	6	21N	6W	1/6/81*	1400	1426-1469	793	SIGW
Cole	Alamos Canyon #3	NE	7	21N	6W	3/5/80*	1260	1282-1312	435	SIGW
Cole	Alamos Canyon #7	NW	7	21N	6W	8/21/80*	1250	1252-1304	880	SIGW
Cole	Alamos Canyon #2	NE	8	21N	6W	2/27/80*	1330	1353-1393	160	SIGW
Cole	Alamos Canyon #5	SW	9	21N	6W	8/31/80*	1320	1326-1362	450	SIGW
Cole	Alamos Canyon #10	NW	15	21N	6W	1/9/81*	1360	1383-1422	475	SIGW
NW Expl.	Natani #1	SE	11	21N	6W	6/28/79	1563	1580-1662	559	SIGW
NW Expl.	Natani #2	NW	12	21N	6W	10/6/79*	1650	1682-1752	688	SIGW
Cole	Alamos Canyon #1	NW	15	21N	6W	3/1/80*	1350	1355-1403	380	SIGW

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.	SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Kirby Exploration	Chorney State #1	SW 16 22N 6W	6/12/76	2270	2305-2346		PA
Benson	Federal #1	SW 17 22N 6W	9/15/78	1886	1903-1954	20	SIGW
Benson	Navajo #1	SW 18 22N 6W	4/30/78	1816	1820-1884	47	SIGW
Dome	Federal #2	SE 18 22N 6W	9/27/80*	1830	1865-1948	329	SIGW
Dome	Federal #3	NW 18 22N 6W	9/14/80*	1858	1874-1922	418	SIGW
Dome	Federal #1	SW 19 22N 6W	1/21/79	1681	1698-1805	359	SIGW
Benson	Federal #1	NE 19 22N 6W	7/8/78	1789	1816-1854	75	SIGW
Benson	Federal #1	SW 20 22N 6W	8/9/78	1780	1798-1848	576	SIGW
Dome	Federal #2	SE 20 22N 6W	8/30/80*	1947	1973-2013	1050	SIGW
Dome	Federal #3	NW 20 22N 6W	10/5/80*	1823	1853-1883	688	SIGW
Eng. Prod. Serv.	Tall Pine #1	SE 26 22N 6W	3/13/76	2030	2066-2158	54	SIGW
Kirby Exploration	Bradshaw Fed. #1	NE 27 22N 6W	6/16/76	2010	2023-2034		PA
Dome	Navajo #1	SW 27 22N 6W	12/11/80*	1737	1770-1790	684	SIGW
Benson	Federal #1	NW 28 22N 6W	7/24/78	1816	1834-2043	668	SIGW
Dome	Navajo #2	SE 28 22N 6W	9/6/80*	1762	1790-1860	918	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Dome	Navajo #4	SW	28	22N	6W	12/4/80*	1698	1734-1756	1429	SIGW
Dome	Federal #3	NE	29	22N	6W	11/24/80*	1804	1830-1860	1265	SIGW
Benson	Federal #1	SE	29	22N	6W	6/23/78	1702	1727-1800	977	SIGW
Dome	Federal #2	SW	29	22N	6W	8/26/80*	1790	1790-1880	960	SIGW
Benson	Dome Rusty #1	NE	30	22N	6W	5/25/78	1734	1758-1854	1509	SIGW
Dome	Federal #1	NW	30	22N	6W	1/31/79	1676	1675-1810	415	SIGW
Benson	Federal #1	SE	31	22N	6W	9/26/78	1536	1552-1600	262	SIGW
Benson	#1 State	NW	32	22N	6W	10/11/78	1637			SUSP
Dome	State #2	NE	32	22N	6W	12/1/80*	1620	1620-1706	1819	SIGW
Dome	Navajo #1	NW	34	22N	6W	12/7/80*	1773	1810-1894	1123	SIGW
Dome	Navajo #1	NW	35	22N	6W	12/15/80*	1912	1946-2034	136	SIGW
Benson	State #1	SW	36W	22N	6W	10/7/78	1766	1795-1831	68	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Navajo #1	NW	9	22N	7W	8/3/78	1780			TA
Beard	#1 Chacra	NW	10	22N	7W	12/3/77	1780	1795-1902		SIGW
Dome	Federal #1	NE	10	22N	7W	9/10/80*	1852	1868-1910	733	SIGW
Benson	Navajo #1	SW	10	22N	7W	7/13/78	1690	1706-1804	866	SIGW
Chase	Gulf Fed. #2	NE	11	22N	7W	8/28/75	1934	1950-1988	700	PROD
Chace	Rusty Fed. #1	SE	11	22N	7W	7/31/74	1900	1901-1962	450	PROD
Chase	2 Gulf Navajo	SW	12	22N	7W	5/22/80*	1852	1967-1991	227	SIGW
Chase	Gulf Fed. #1	NW	13	22N	7W	2/28/75	1930	1969-2041	581	PROD
Chase	Gulf Fed. #3	NE	13	22N	7W	2/16/76	1930	1943-1980	348	PROD
Chase	Rusty Fed. #4	SW	13	22N	7W	10/8/75	1740	1758-1801	1423	PROD
Chase	Rusty Fed. #2	NE	14	22N	7W	2/21/75	1830	1880-1884	457	PROD
Chase	Rusty Fed. #3	SE	14	22N	7W	9/4/75	1750	1762-1804	1472	PROD
Dome	Federal #1	SE	15	22N	7W	1/16/79	1672	1708-1784	817	SIGW
Benson	Navajo #1	SE	17	22N	7W	7/17/78	1518	1719-1782		WOCU
Dome	Navajo #2	SW	17	22N	7W	9/19/80*	1471	1484-1572	133	SIGW
Dome	Navajo #1	NE	20	22N	7W	1/9/79	1470	1487-1520	158	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Dome Rusty #1	SE	20	22N	7W	6/23/78	1426	1440-1600	482	SIGW
Benson	Navajo #1	NE	21	22N	7W	5/30/78	1516	1543-1640	470	SIGW
Beard	#2 Chacra	SE	21	22N	7W	12/12/77	1445	1456-1562	NR	SIGW
Chase	Rusty Navajo #5	NE	22	22N	7W	11/14/76	1660	1695-1917	960	PROD
Chase	Rusty Navajo #7	SW	22	22N	7W	4/16/77	1440	1564-1812	769	PROD
Chase	Rusty Navajo #2	NW	23	22N	7W	1/28/76	1665	1692-1776	802	PROD
Chase	Rusty Navajo 1-X	NE	23	22N	7W	1/31/76	1642	1667-1763	900	PROD
Chase	Rusty Navajo #3	SW	23	22N	7W	7/19/76	1524	1540-1743	298	PROD
Benson	Dome Rusty #1	SE	24	22N	7W	6/9/78	1636	1650-1699	569	SIGW
Benson	Federal #1	NE	25	22N	7W	10/24/78	1588			WOCU
Benson	Federal #1	NE	26	22N	7W	8/6/78	1510	1526-1730	544	SIGW
Chase	Rusty Navajo #4	NW	26	22N	7W	7/22/76	1510	1515-1731	404	PROD
Chase	Rusty Navajo #6	NE	27	22N	7W	5/3/77	1440	1465-1572	272	PROD
Merrion/Bayless	#2 Alemita	NW	28	22N	7W	2/27/78	1400	1507-1514	NR	SUSP
Dome	Navajo #2	SE	28	22N	7W	9/23/80*	1328	1342-1376	24	SIGW
Dome	Federal #1	NE	34	22N	7W	9/29/80*	1390	1405-1470	26	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

K•E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

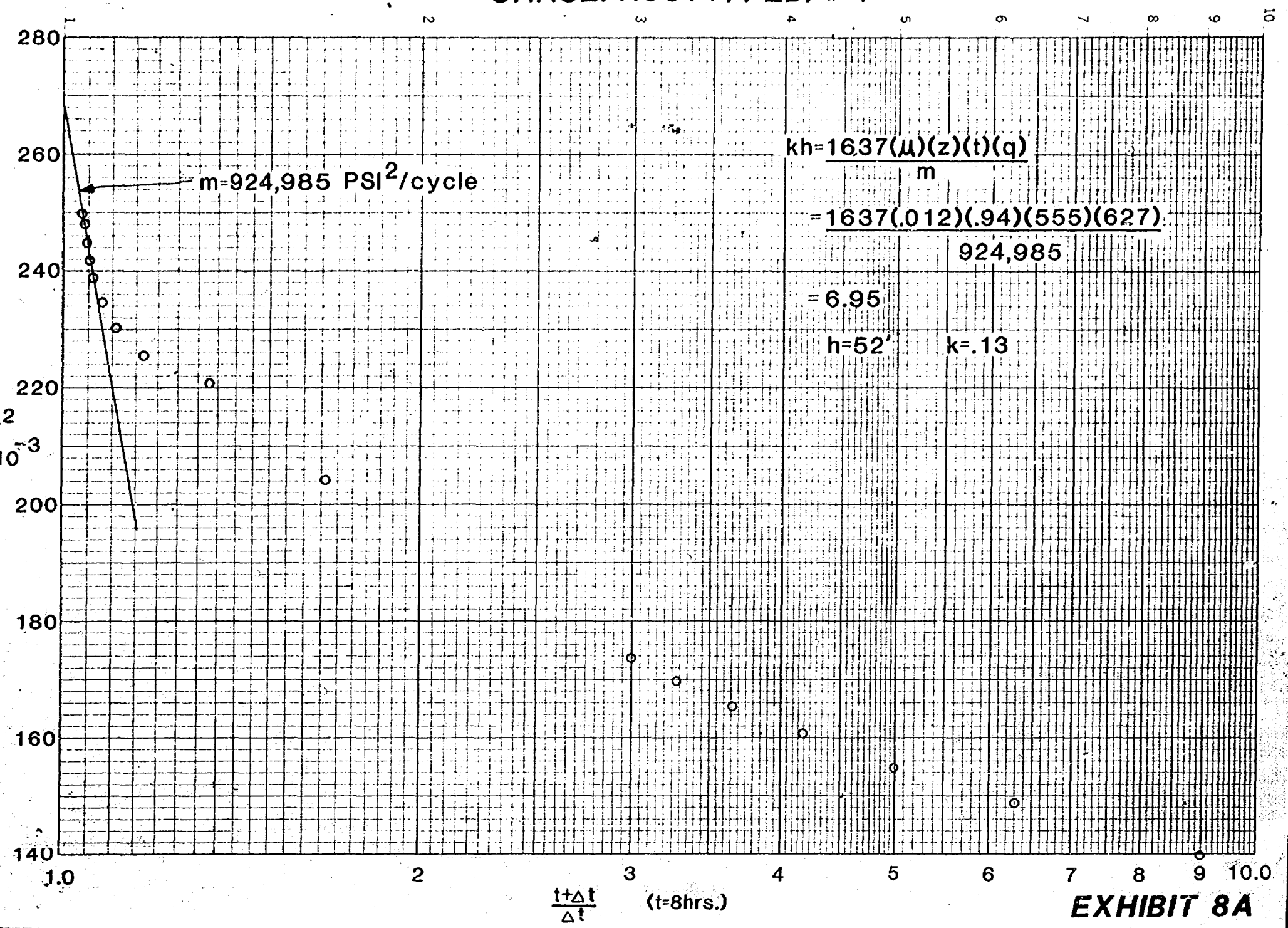


EXHIBIT 8A

K•E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN USA

CHASE/RUSTY/FED. #4

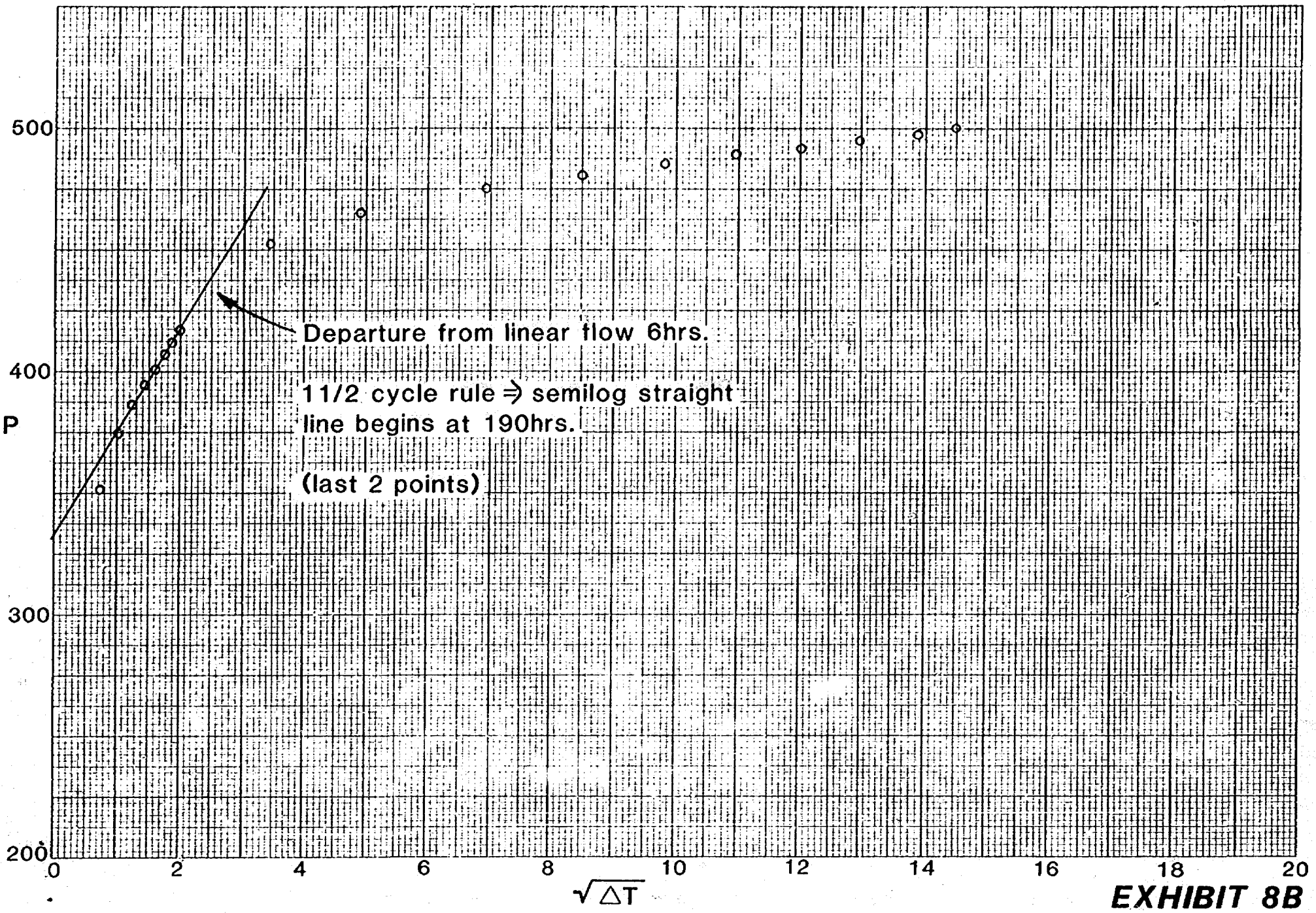


EXHIBIT 8B

K&E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

$$kh = \frac{1637(\mu)(t)(z)(q)}{m}$$

$$= \frac{1637(.0121)(626)(.97)(101)}{258458}$$

$$= 4.7$$

h=100 k=.047

m=258458 PSI^2/cycle

p^2 X10^{-3}

170
160
150
140

1 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ (t=8.72hrs.)

EXHIBIT 9A

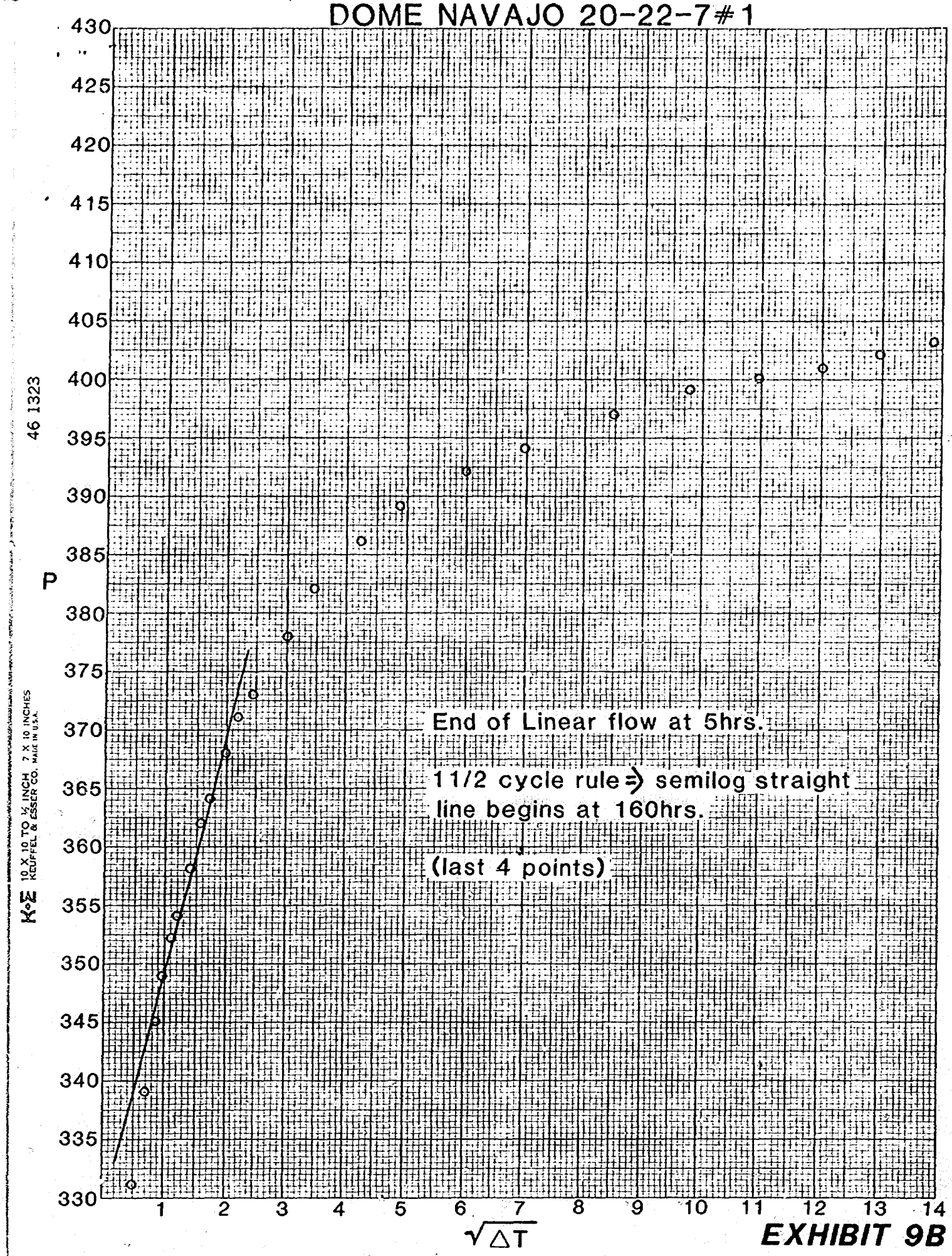

DOME NAVAJO 20-22-7#1
46 1323
P
430
425
420
415
410
405
400
395
390
385
380
375
370
365
360
355
350
345
340
335
330
End of Linear flow at 5hrs.
1 1/2 cycle rule ⇒ semilog straight line begins at 160hrs.
(last 4 points)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
√ΔT
10 X 10 TO ½ INCH. 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.
K•E

EXHIBIT 9B

K•E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO MADE IN U.S.A.

46 4652

DOME/FED. 19-22-6#1

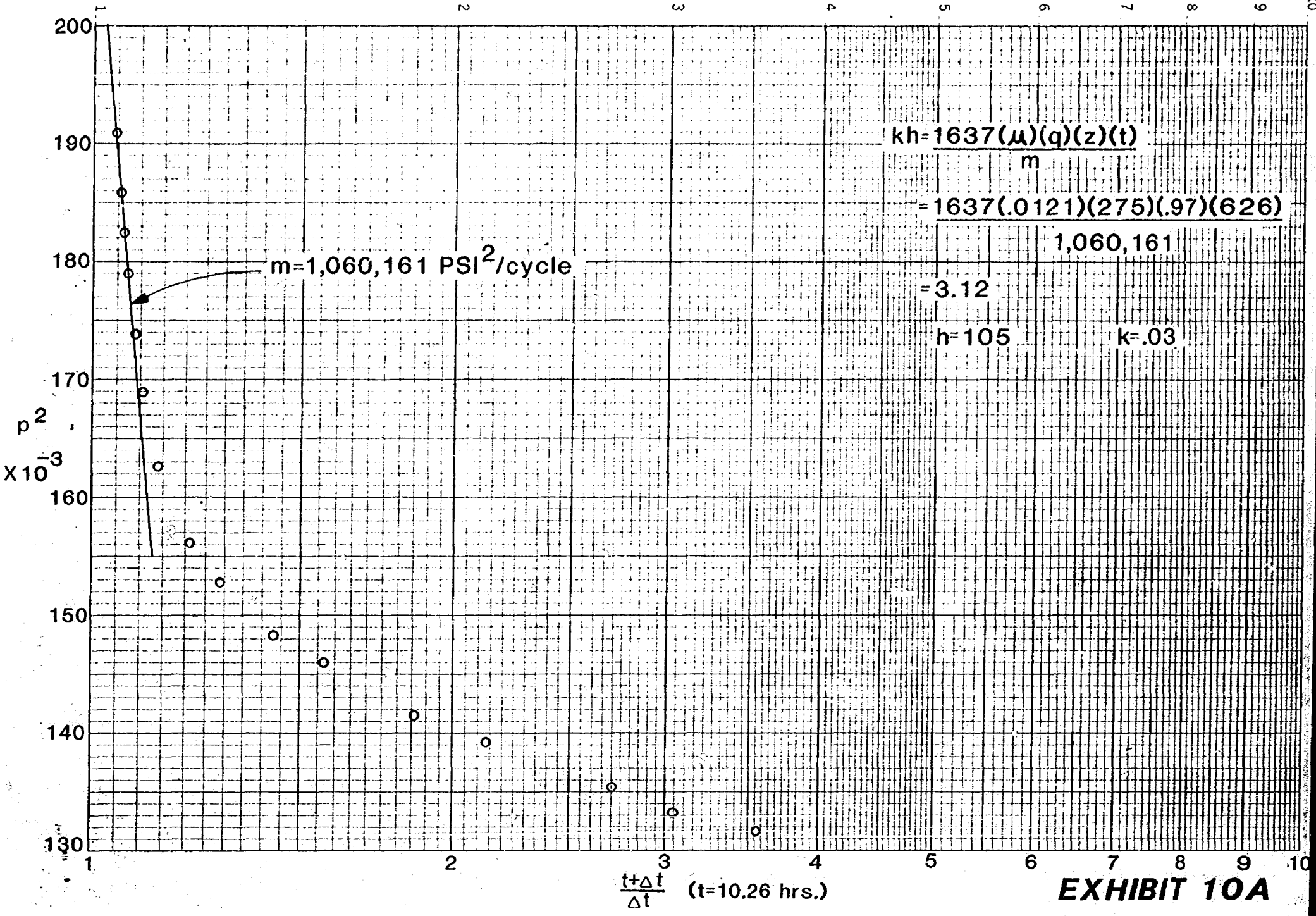


EXHIBIT 10A

DOME FED. 19-22-6#1

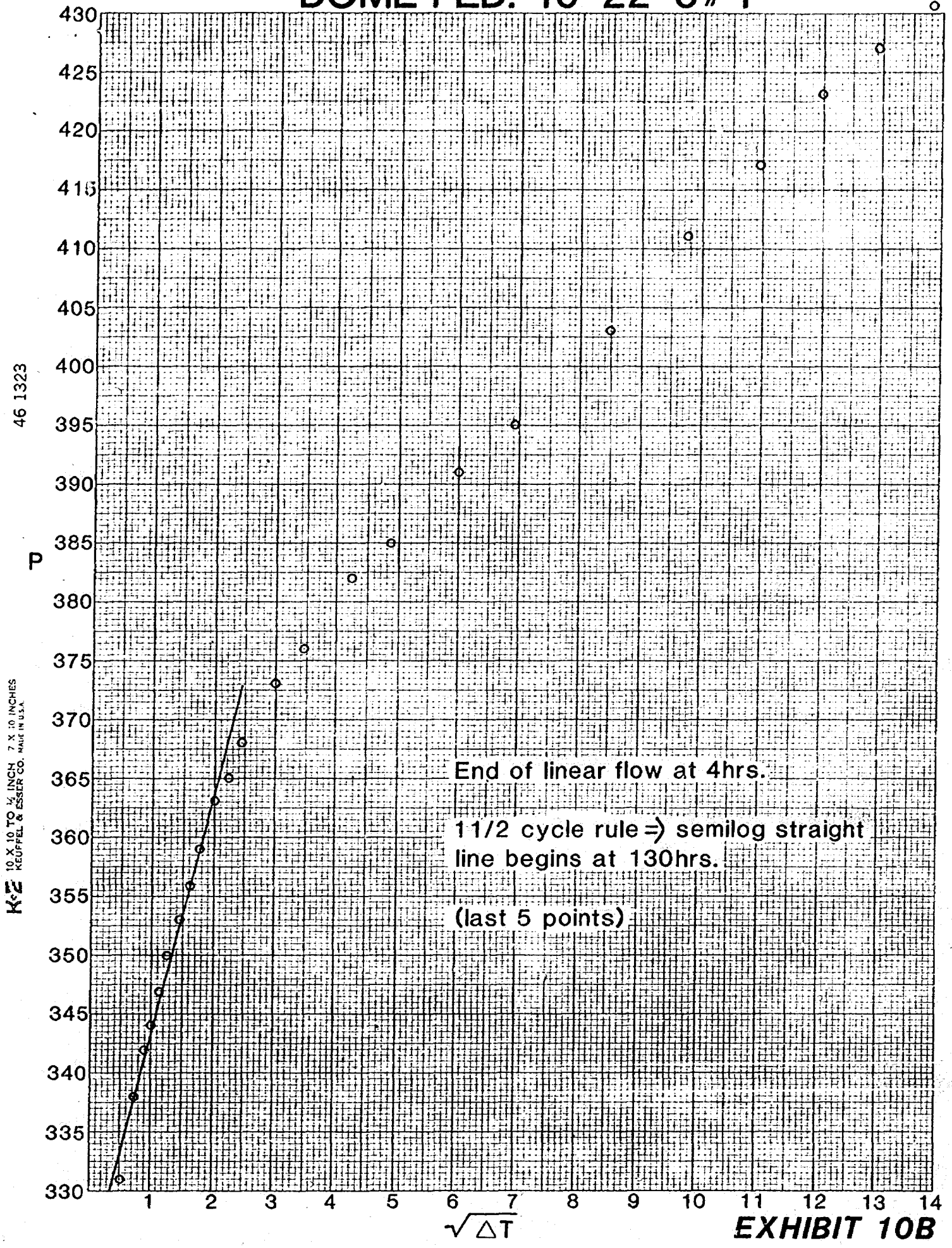


EXHIBIT 10B

RUSTY CHACRA AREA

WELLS WITH MEASURED UNSTIMULATED RATES

EXHIBIT 11

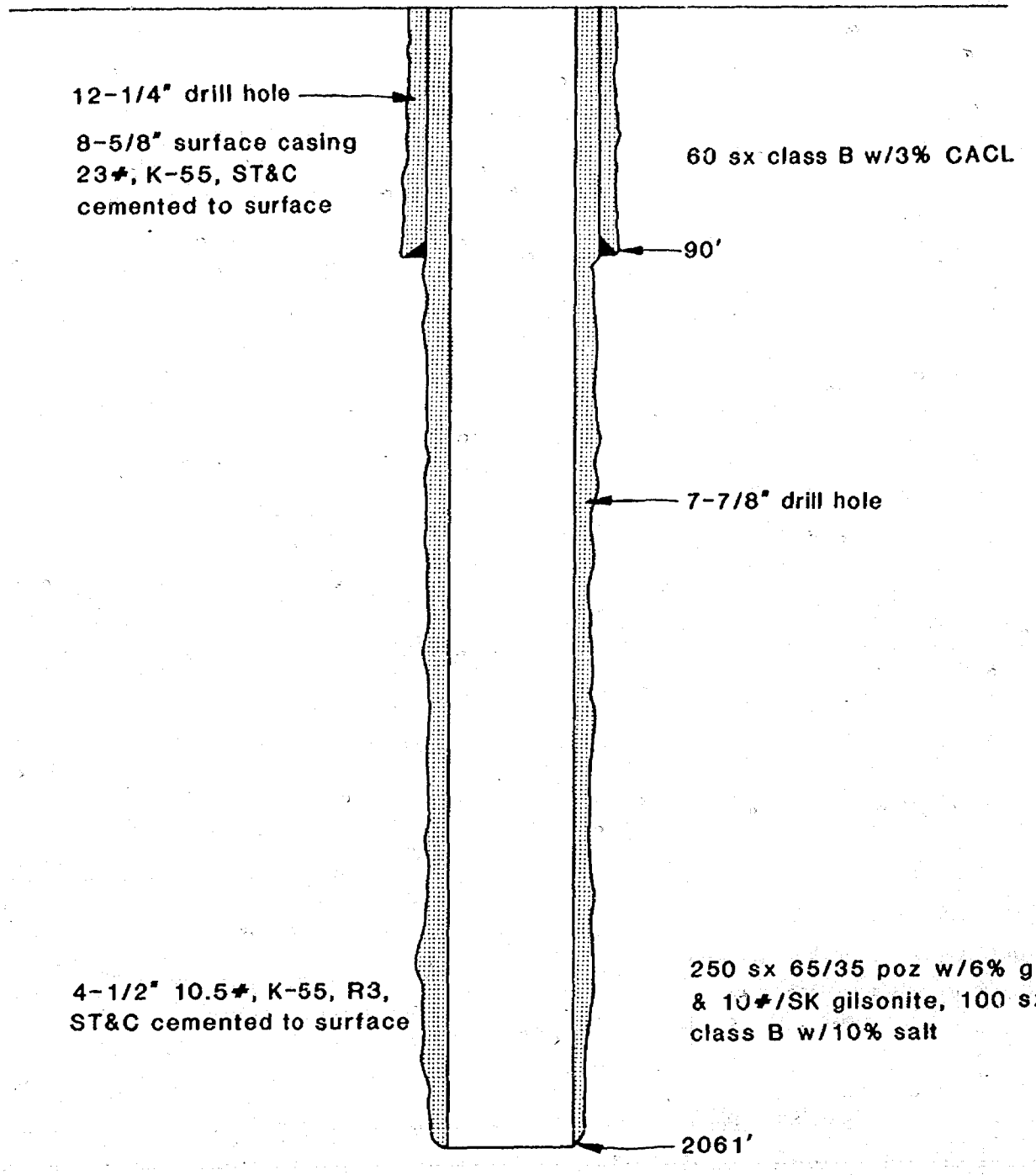
Operator	Well	Location Qtr.,	Sec.,	TWP.,	RNG.	Unstimulated Rate MCFD	3 Hr. Potential After frac MCFD
Dome	Navajo #2	SE	28	22N	7W	0	24
Eng. Prod. Serv.	Tall Pine #1	SE	26	22N	6W	TSTM	54
Dome	Navajo #2	SE	28	22N	6W	0	918
Dome	Navajo #4	SW	28	22N	6W	0	1429
Dome	Federal #3	NE	29	22N	6W	0	1265
Dome	Federal #2	SW	29	22N	6W	TSTM	960
Dome	State #2	NE	32	22N	6W	52	1819
Dome	Navajo #1	NW	34	22N	6W	0	1123
Dome	Navajo #1	NW	35	22N	6W	0	136

TYPICAL CASING DESIGN

RUSTY CHACRA AREA

(Dome/Fed. #1 30-22-6)

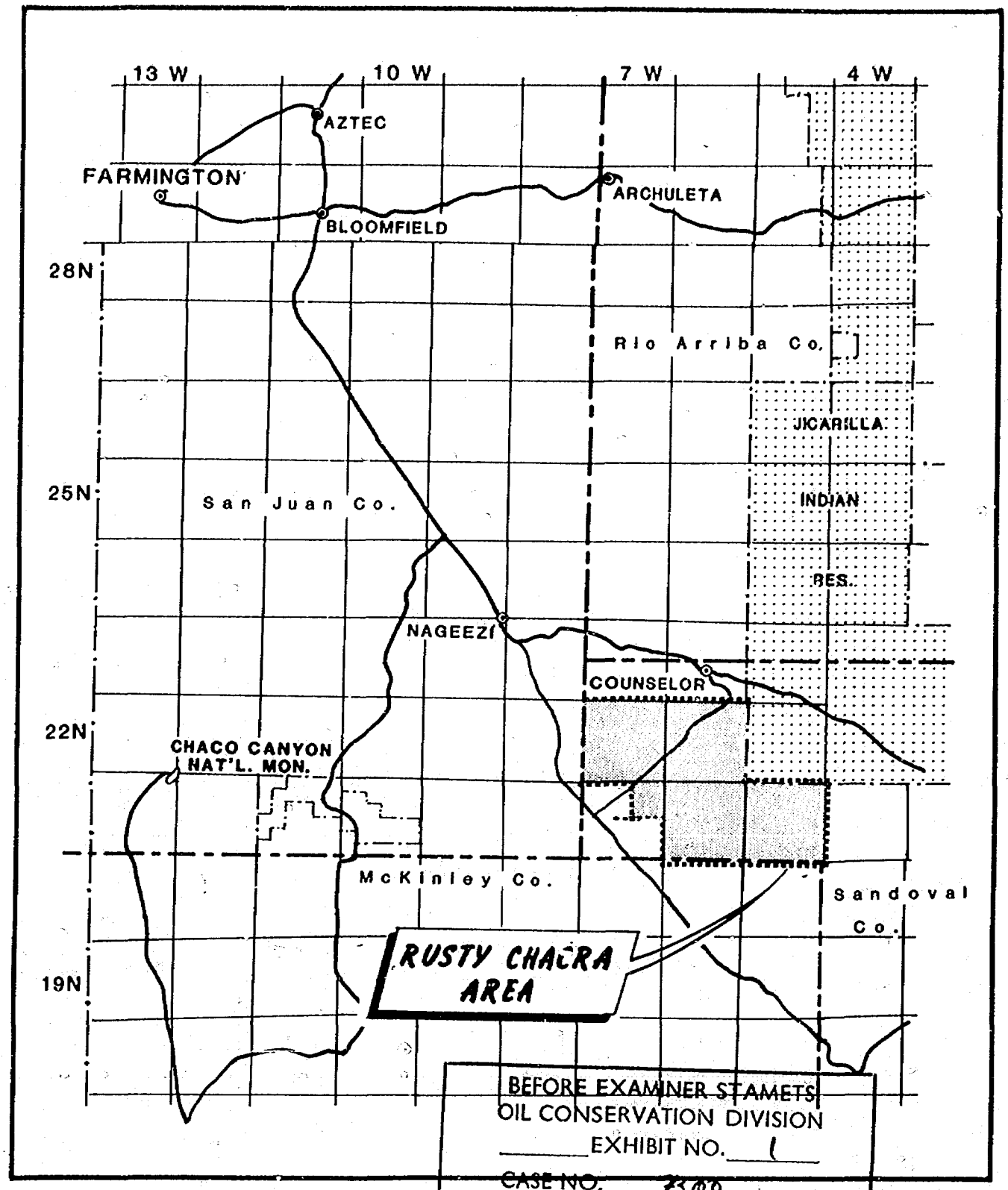
EXHIBIT #12



SUMMARY OF EXHIBITS

RUSTY CHACRA AREA

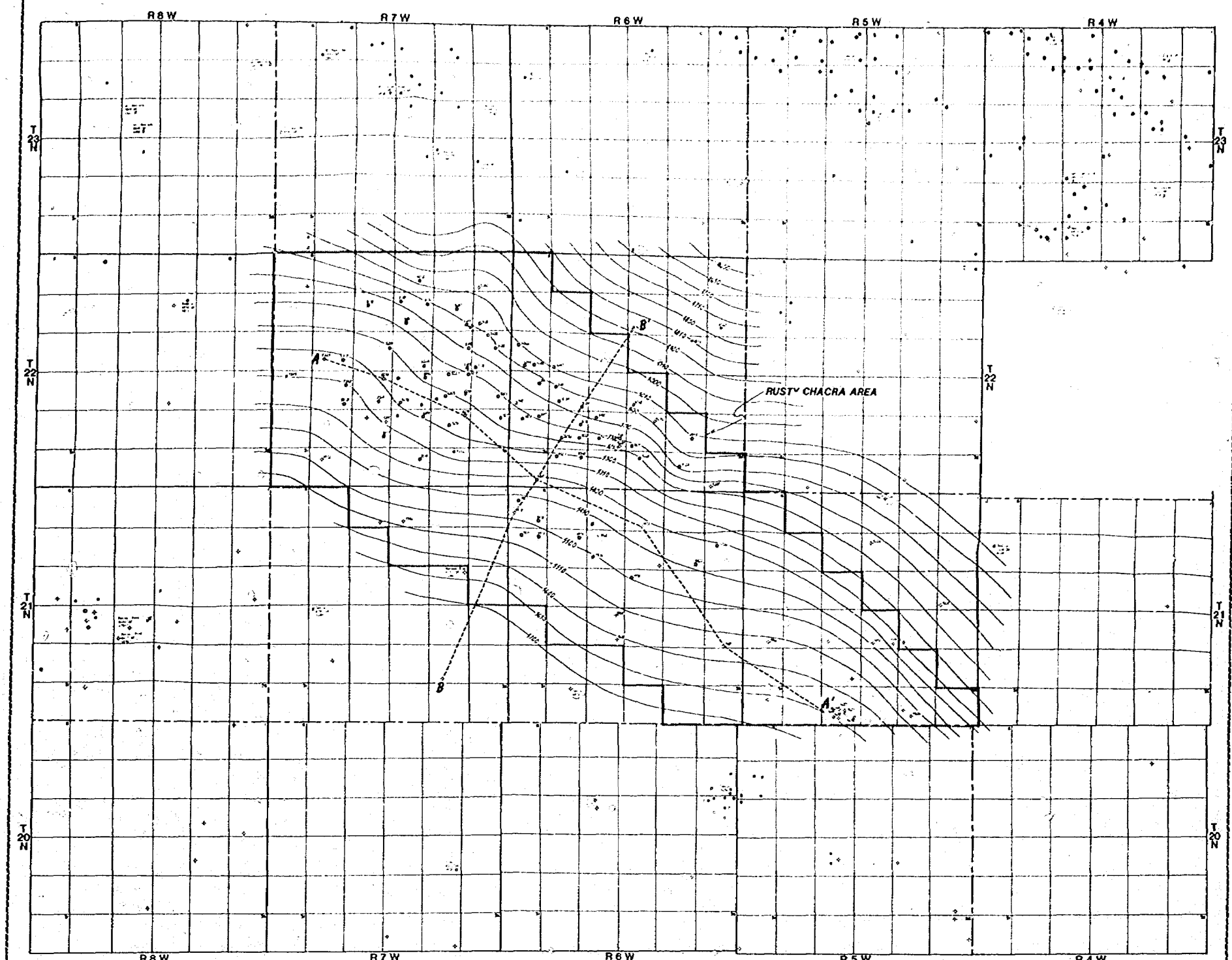
Exhibit No.	Title or Subject
1	Index map showing relative location of application area
2	Structure Map
3	Summary of Geology
4	Cross Section
5	Type Log
6	Summary of Reservoir data
7	Summary of Pertinent Data by well
8	Pressure Build-up analysis Chase Rusty Federal #4 Horner plot and P vs $\sqrt{\Delta t}$ plot
9	Pressure Build-up analysis Dome Navajo 20-22-7 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
10	Pressure Build-up analysis Dome Federal 19-22-6 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
11	Summary of wells with measured unstimulated rates
12	Typical casing design



BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 1
CASE NO. 7300
Submitted by Dome
Hearing Date 7/22/81

INDEX MAP OF NORTH WESTERN NEW MEXICO
SHOWING RELATIVE LOCATION OF
RUSTY CHACRA AREA

Exhibit 1



BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 2
CASE NO. 7800
Submitted by Dome
Hearing Date 7/2/81

DOME PETROLEUM CORP.
RUSTY CHACRA AREA
SANDOVAL CO., NEW MEXICO
Structure Contours on Top "Chacra" Zone
Proposed Tight Gas Formation Area
Exhibit #2
DATE 6/81 | GEOLOGY BY MAPLICHS | FILE NO. 813

Rusty Chacra Area Tight Gas Hearing

Exhibit #3

Summary of Geology

The Rusty Chacra Area is located six miles south of the town of Counselor in Sandoval Co., New Mexico. Geologically, the area is located on the Chaco Slope of the southern San Juan Basin. Gas production is from a buildup of transitional shaly sands and siltstones which are interpreted to be of a prodelta low-energy origin. This productive zone which is called the "Chacra" is the time-stratigraphic equivalent of the upper Unnamed Tongue of the Cliffhouse beach sandstone. Structural dip to the north-east of about 100 feet per mile is of little consequence as this is a stratigraphic trap. The sandstones are gray to light gray, fine grained, silty, shaly, and slightly to moderately calcitic.

The fine grained and clay filled nature of the sands results in low porosity and permeability and commercial production when obtained is only achieved through extensive fracturing and reservoir treatment.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 3
CASE NO. 7300
Submitted by Dome
Hearing Date 7/2/81

ENGINEERING SUMMARY
CHACRA FORMATION
RUSTY CHACRA AREA

Exhibits 6 through 12 will help illustrate that the Chacra sandstone meets the requirements to qualify for tight gas formation incentive pricing. The exhibits will show: (1) the average in-situ permeability is less than 0.10 md; (2) the average pre-stimulation stabilized flow rate is less than 18 CFR 271.705 guidelines; (3) oil production is less than 5 BOPD; and (4) any fresh water zones are protected from contamination.

EXHIBIT NO. 6 - Summary of Reservoir Data

This table shows typical reservoir data for the Chacra sandstone within the application area. This information shows that the criteria for permeability, unstimulated flow rate, and crude oil production are all met. The average depth to the top of the Chacra formation of 1658' is derived from the data presented in exhibit 7. The calculation of the average permeability of 0.07 md is detailed in exhibits 8, 9, and 10 while the average unstimulated rate of gas to small to measure is derived from exhibit 11.

EXHIBIT 7 - Summary of Pertinent Data by Well

These tables show all of the Chacra sandstone wells within the application area. Averages of the depth to the top of the Chacra as well as the average three hour potential test after fracture stimulation were shown in exhibit 6. The tables also give well locations, completion interval, spud date and current well status. As shown, most of the wells in this area are shut-in gas wells which are waiting on pipeline connections.

EXHIBIT 8, 9, and 10 - Pressure Build-up Analysis

These exhibits show how in-situ permeability to gas was calculated for each of three Chacra wells which had extended pressure build-ups. For each of the three wells a Horner plot of pressure squared vs. $(t + \Delta t)/\Delta t$ is shown as well as a plot of pressure vs. $\sqrt{\Delta t}$. The straight line portion of the Horner plot is used to calculate permeability. Early data is affected by wellbore storage and linear flow in fractures induced by hydraulic fracture stimulation treatment. The second plot of pressure vs. $\sqrt{\Delta t}$ helps to show which part of the Horner plot should be used in the calculation of permeability and which part is still affected by linear flow and storage. The results of these three extended pressure surveys are as follows:

WELL	IN-SITU PERMEABILITY
Chase Rusty Federal #4	0.13 md
Dome Navajo 20-22-7 #1	0.05 md
Dome Federal 19-22-6 #1	0.04 md
Average	0.07 md

EXHIBIT 11 - Summary of Wells with Measured Unstimulated Rates

This table shows the Chacra completions in which unstimulated rates were reported after swabbing the well down prior to fracture treatment. The standard procedure in this area has been to stimulate the well immediately after perforating by hydraulic fracturing methods. Due to this procedure unsimulated rates were

generally not reported except for the wells shown in this table. This table shows that in all cases unstimulated rates were below the guidelines given in 18 CFR 271.705 which specifies for 1658' (the average depth to the top of the Chacra) a maximum unstimulated rate of 59 MCFD. The average for the wells shown in this exhibit is a rate too small to measure and represents the expected unstimulated rate for this formation. It should also be noted that none of these wells have produced any crude oil before or after stimulation.

EXHIBIT 12 - Typical Casing Design

This exhibit shows how any potential fresh water zones would be protected by surface casing and production casing which are both cemented to surface.

KFT:jp

SUMMARY OF RESERVOIR DATA

RUSTY CHACRA AREA

Exhibit 6

Reservoir Temperature	160 degrees F
Average Reservoir Pressure	460 psia
Average Depth to Top of Chacra	1658'
Average Porosity	11%
Average Permeability	0.07 md
Average Unstimulated Flow Rate	TSTM
Average 3 hr. Potential Test Rate	594 MCFD
Crude Oil Production	None

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 6
CASE NO. 7300
Submitted by Dome
Hearing Date 7/2/81

K•E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

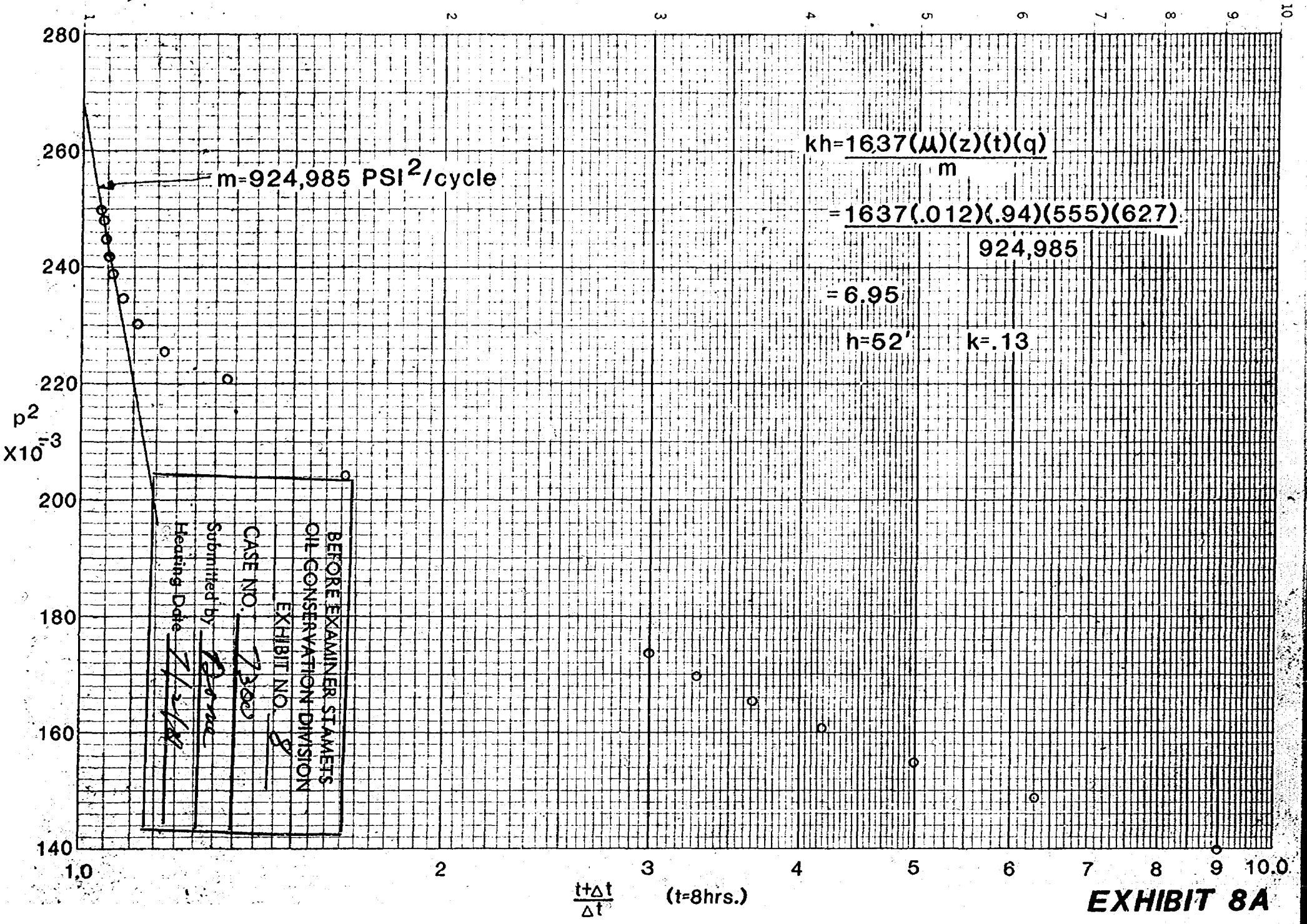


EXHIBIT 8A

K&E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

CHASE/RUSTY/FED. #4

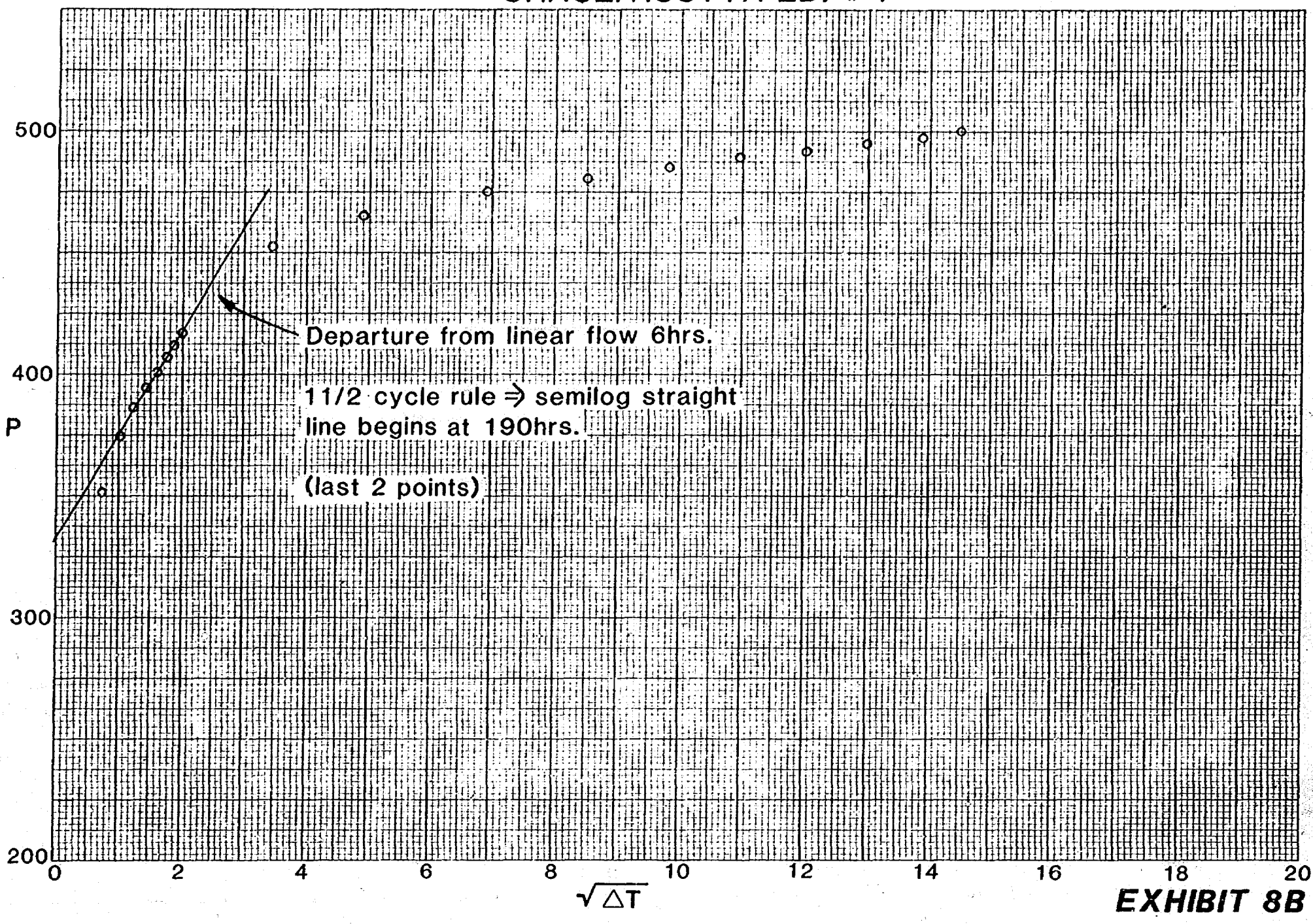


EXHIBIT 8B

K•Σ SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

$$kh = \frac{1637(\mu)(t)(z)(q)}{m}$$

$$= \frac{1637(.0121)(626)(.97)(101)}{258458}$$

$$= 4.7$$

h=100 k=.047

m=258458 PSI^2/cycle

p^2 X10^{-3}

170
160
150
140

1 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ (t=8.72hrs.)

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 9
CASE NO. 7300
Submitted by Dome
Hearing Date 7/22/81

EXHIBIT 9A

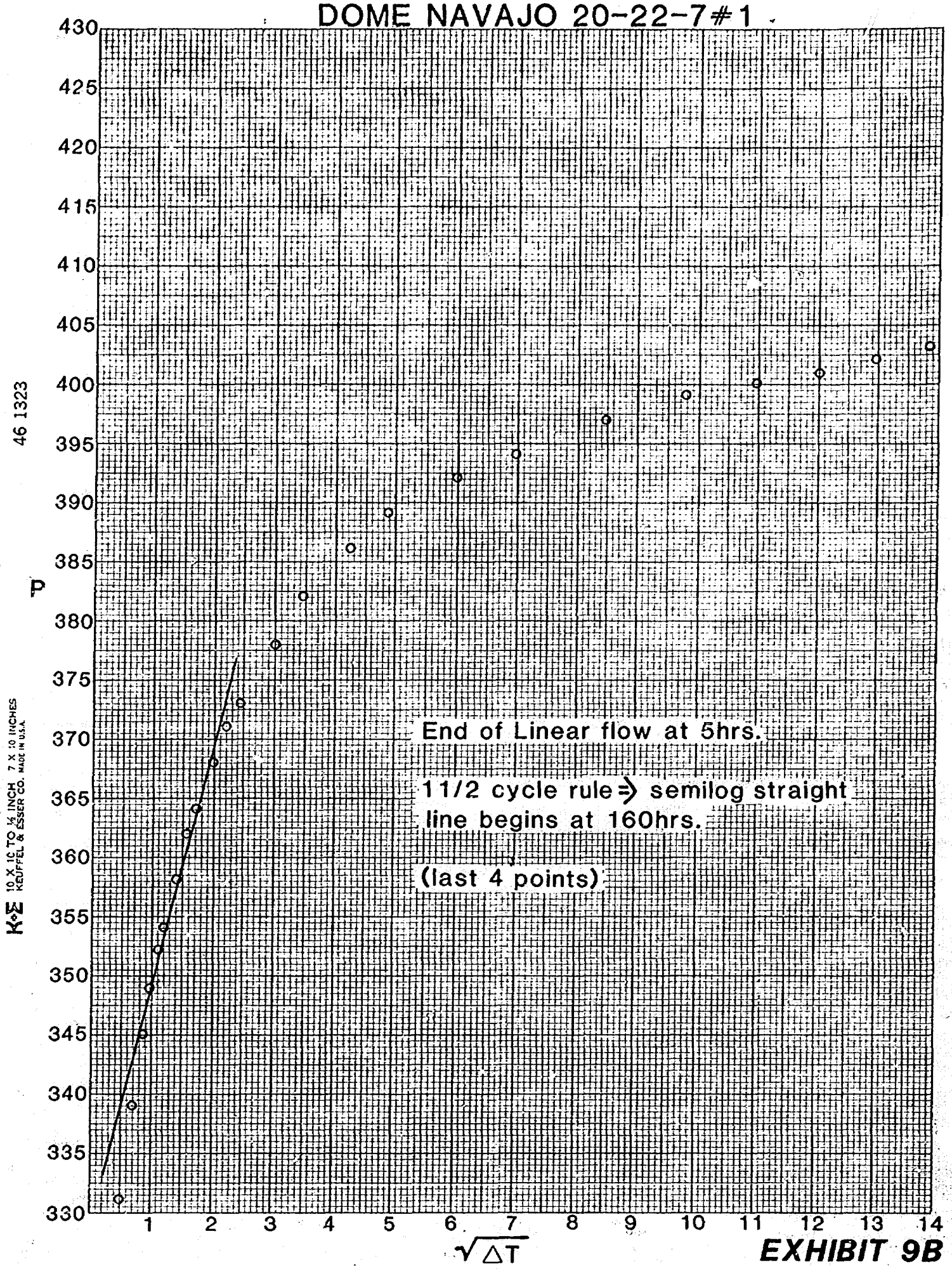

DOME NAVAJO 20-22-7#1
46 1323
P
End of Linear flow at 5hrs.
11/2 cycle rule ⇒ semilog straight line begins at 160hrs.
(last 4 points)
430
425
420
415
410
405
400
395
390
385
380
375
370
365
360
355
350
345
340
335
330
1 2 3 4 5 6 7 8 9 10 11 12 13 14
√ΔT
K+E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

EXHIBIT 9B

K&E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME/FED. 19-22-6#1

$kh = \frac{1637(\mu)(q)(z)(t)}{m}$

$= \frac{1637(.0121)(275)(.97)(626)}{1,060,161}$

$= 3.12$

$h = 105$ $k = .03$

$m = 1,060,161\ PSI^2/cycle$

$p^2 \times 10^{-3}$

200
190
180
170
160
150
140
130

1 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ (t=10.26 hrs.)

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 10
CASE NO. 7300
Submitted by Dome
Hearing Date 7/21/81

EXHIBIT 10A

DOME FED. 19-22-6#1

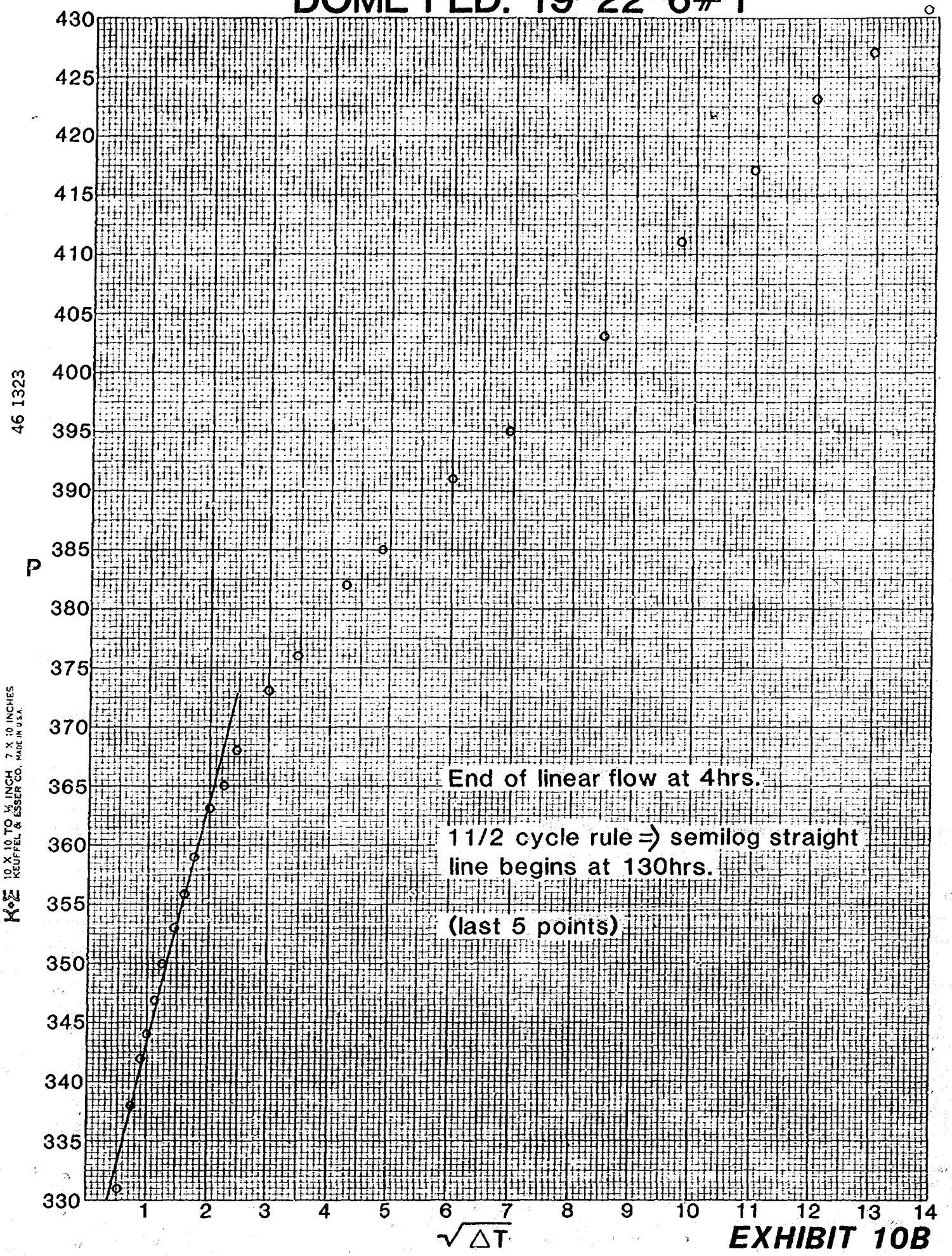


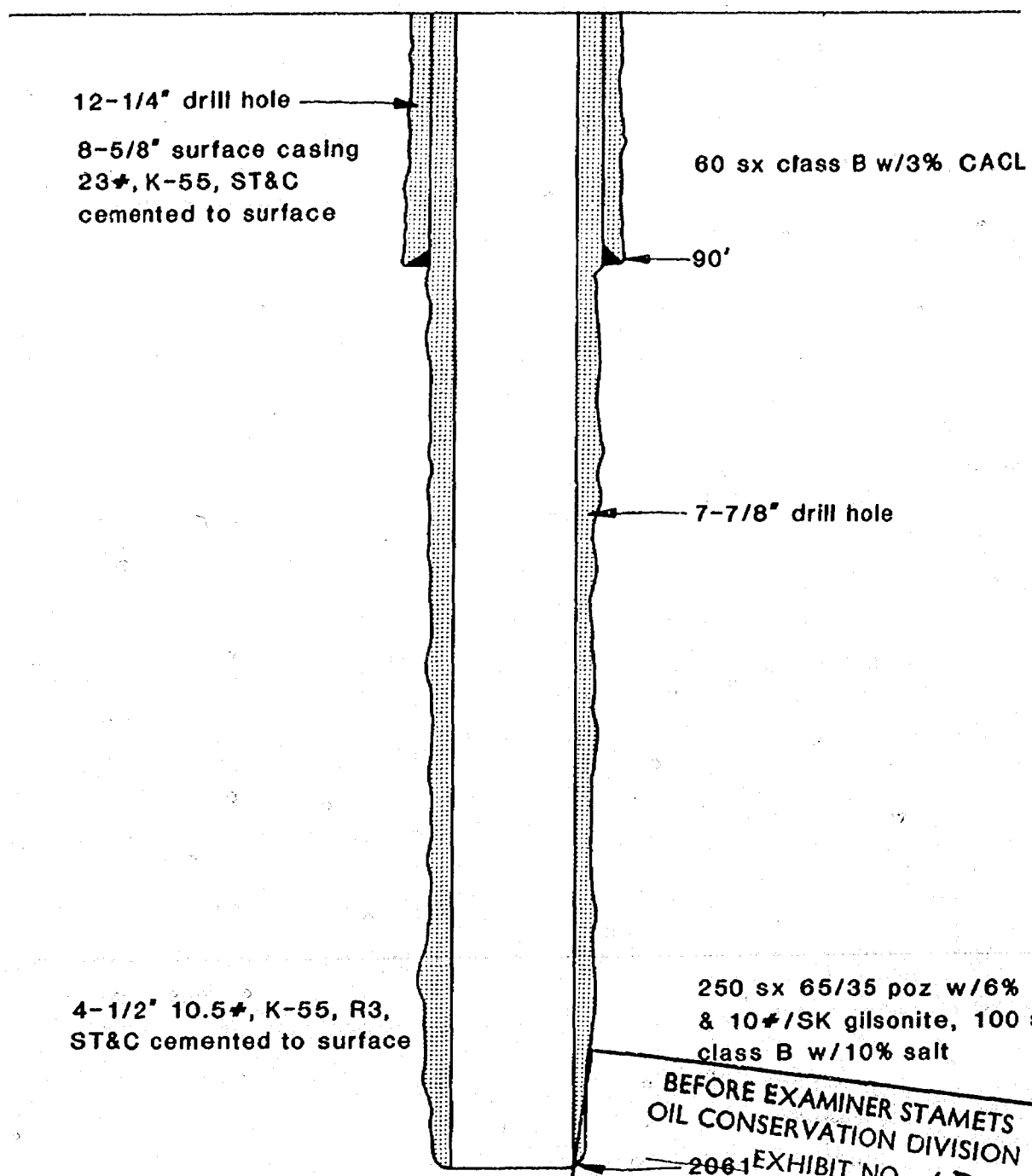
EXHIBIT 10B

TYPICAL CASING DESIGN

RUSTY CHACRA AREA

(Dome/Fed. #1 30-22-6)

EXHIBIT #12



BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 12
CASE NO. 7300
Submitted by Dome
Hearing Date 7/2/81

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Cole	Alamos Canyon #11	SW	4	21N	6W	1/11/81*	1370	1396-1436	275	SIGW
Cole	Alamos Canyon #6	SE	6	21N	6W	8/18/80*	1304	1304-1343	1025	SIGW
Cole	Alamos Canyon #9	NW	6	21N	6W	1/6/81*	1400	1426-1469	793	SIGW
Cole	Alamos Canyon #3	NE	7	21N	6W	3/5/80*	1260	1282-1312	435	SIGW
Cole	Alamos Canyon #7	NW	7	21N	6W	8/21/80*	1250	1252-1304	880	SIGW
Cole	Alamos Canyon #2	NE	8	21N	6W	2/27/80*	1330	1353-1393	160	SIGW
Cole	Alamos Canyon #5	SW	9	21N	6W	8/31/80*	1320	1326-1362	450	SIGW
Cole	Alamos Canyon #10	NW	9	21N	6W	1/9/81*	1360	1383-1422	475	SIGW
NW Expl.	Natani #1	SE	11	21N	6W	6/28/79	1563	1580-1662	559	SIGW
NW Expl.	Natani #2	NW	12	21N	6W	10/6/79*	1650	1682-1752	688	SIGW
Cole	Alamos Canyon #1	NW	15	21N	6W	3/1/80*	1350	1355-1403	380	SIGW

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 7
CASE NO. 7300
Submitted by Dome
Hearing Date 7/2/81

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Kirby Exploration	Chorney State #1	SW	16	22N	6W	6/12/76	2270	2305-2346		PA
Benson	Federal #1	SW	17	22N	6W	9/15/78	1886	1903-1954	20	SIGW
Benson	Navajo #1	SW	18	22N	6W	4/30/78	1816	1820-1884	47	SIGW
Dome	Navajo #2	SE	18	22N	6W	10/5/80*	1830	1865-1948	329	SIGW
Dome	Federal #3	NW	18	22N	6W	9/14/80*	1858	1874-1922	418	SIGW
Dome	Federal #1	SW	19	22N	6W	1/21/79	1681	1698-1805	359	SIGW
Benson	Federal #1	NE	19	22N	6W	7/8/78	1789	1816-1854	75	SIGW
Benson	Federal #1	SW	20	22N	6W	8/9/78	1780	1798-1848	576	SIGW
Dome	Federal #2	SE	20	22N	6W	8/30/80*	1947	1973-2013	1050	SIGW
Dome	Federal #3	NW	20	22N	6W	10/5/80*	1823	1853-1883	688	SIGW
Eng. Prod. Serv.	Tall Pine #1	SE	26	22N	6W	3/13/76	2030	2066-2158	54	SIGW
Kirby Exploration	Bradshaw Fed. #1	NE	27	22N	6W	6/16/76	2010	2023-2034		PA
Dome	Navajo #1	SW	27	22N	6W	12/11/80*	1737	1770-1790	684	SIGW
Benson	Federal #1	NW	28	22N	6W	7/24/78	1816	1834-2043	668	SIGW
Dome	Navajo #2	SE	28	22N	6W	9/6/80*	1762	1790-1860	918	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Dome	Navajo #4	SW	28	22N	6W	12/4/80*	1698	1734-1756	1429	SIGW
Dome	Federal #3	NE	29	22N	6W	11/24/80*	1804	1830-1860	1265	SIGW
Benson	Federal #1	SE	29	22N	6W	6/23/78	1702	1727-1800	977	SIGW
Dome	Federal #2	SW	29	22N	6W	8/26/80*	1790	1790-1880	960	SIGW
Benson	Dome Rusty #1	NE	30	22N	6W	5/25/78	1734	1758-1854	1509	SIGW
Dome	Federal #1	NW	30	22N	6W	1/31/79	1676	1675-1810	415	SIGW
Benson	Federal #1	SE	31	22N	6W	9/26/78	1536	1552-1600	262	SIGW
Benson	#1 State	NW	32	22N	6W	10/11/78	1637			SUSP
Dome	State #2	NE	32	22N	6W	12/1/80*	1620	1620-1706	1819	SIGW
Dome	Navajo #1	NW	34	22N	6W	12/7/80*	1773	1810-1894	1123	SIGW
Dome	Navajo #1	NW	35	22N	6W	12/15/80*	1912	1946-2034	136	SIGW
Benson	State #1	SW	36W	22N	6W	10/7/78	1766	1795-1831	68	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Navajo #1	NW	9	22N	7W	8/3/78	1780			TA
Beard	#1 Chacra	NW	10	22N	7W	12/3/77	1780	1795-1902		SIGW
Dome	Federal #1	NE	10	22N	7W	9/10/80*	1852	1868-1910	733	SIGW
Benson	Navajo #1	SW	10	22N	7W	7/13/78	1690	1706-1804	866	SIGW
Chase	Gulf Fed. #2	NE	11	22N	7W	8/28/75	1934	1950-1988	700	PROD
Chase	Rusty Fed. #1	SE	11	22N	7W	7/31/74	1900	1901-1962	450	PROD
Chase	2 Gulf Navajo	SW	12	22N	7W	5/22/80*	1852	1967-1991	227	SIGW
Chase	Gulf Fed. #1	NW	13	22N	7W	2/28/75	1930	1969-2041	581	PROD
Chase	Gulf Fed. #3	NE	13	22N	7W	2/16/76	1930	1943-1980	348	PROD
Chase	Rusty Fed. #4	SW	13	22N	7W	10/8/75	1740	1758-1801	1423	PROD
Chase	Rusty Fed. #2	NE	14	22N	7W	2/21/75	1830	1880-1884	457	PROD
Chase	Rusty Fed. #3	SE	14	22N	7W	9/4/75	1750	1762-1804	1472	PROD
Dome	Federal #1	SE	15	22N	7W	1/16/79	1672	1708-1784	817	SIGW
Benson	Navajo #1	SE	17	22N	7W	7/17/78	1518	1719-1782		WOCU
Dome	Navajo #2	SW	17	22N	7W	9/19/80*	1471	1484-1572	133	SIGW
Dome	Navajo #1	NE	20	22N	7W	1/9/79	1470	1487-1520	158	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Dome Rusty #1	SE	20	22N	7W	6/23/78	1426	1440-1600	482	SIGW
Benson	Navajo #1	NE	21	22N	7W	5/30/78	1516	1543-1640	470	SIGW
Beard	#2 Chacra	SE	21	22N	7W	12/12/77	1445	1456-1562	NR	SIGW
Chase	Rusty Navajo #5	NE	22	22N	7W	11/14/76	1660	1695-1917	960	PROD
Chase	Rusty Navajo #7	SW	22	22N	7W	4/16/77	1440	1564-1812	769	PROD
Chase	Rusty Navajo #2	NW	23	22N	7W	1/28/76	1665	1692-1776	802	PROD
Chase	Rusty Navajo 1-X	NE	23	22N	7W	1/31/76	1642	1667-1763	900	PROD
Chase	Rusty Navajo #3	SW	23	22N	7W	7/19/76	1524	1540-1743	298	PROD
Benson	Dome Rusty #1	SE	24	22N	7W	6/9/78	1636	1650-1699	569	SIGW
Benson	Federal #1	NE	25	22N	7W	10/24/78	1588			WOCU
Benson	Federal #1	NE	26	22N	7W	8/6/78	1510	1526-1730	544	SIGW
Chase	Rusty Navajo #4	NW	26	22N	7W	7/22/76	1510	1515-1731	404	PROD
Chase	Rusty Navajo #6	NE	27	22N	7W	5/3/77	1440	1465-1572	272	PROD
Merrion/Bayless	#2 Alemita	NW	28	22N	7W	2/27/78	1400	1507-1514	NR	SUSP
Dome	Navajo #2	SE	28	22N	7W	9/23/80*	1328	1342-1376	24	SIGW
Dome	Federal #1	NE	34	22N	7W	9/29/80*	1390	1405-1470	26	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA AREA

WELLS WITH MEASURED UNSTIMULATED RATES

EXHIBIT 11

Operator	Well	Location Qtr., Sec., TWP., RNG.				Unstimulated Rate MCFD	3 Hr. Potential After frac MCFD
Dome	Navajo #2	SE	28	22N	7W	0	24
Eng. Prod. Serv.	Tall Pine #1	SE	26	22N	6W	TSTM	54
Dome	Navajo #2	SE	28	22N	6W	0	918
Dome	Navajo #4	SW	28	22N	6W	0	1429
Dome	Federal #3	NE	29	22N	6W	0	1265
Dome	Federal #2	SW	29	22N	6W	TSTM	960
Dome	State #2	NE	32	22N	6W	52	1819
Dome	Navajo #1	NW	34	22N	6W	0	1123
Dome	Navajo #1	NW	35	22N	6W	0	136

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 11
CASE NO. 7300
Submitted by Dome
Hearing Date 7/22/81

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico. CASE 7300

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:
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Ernest L. Padilla, Esq.
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I N D E X

STATEMENT BY MR. BATEMAN 4

MICHAEL FUCHS

Direct Examination By Mr. Bateman 5

Cross Examination by Mr. Stamets 12

KEVIN TRACY

Direct Examination by Mr. Bateman 13

Questions by Mr. Chavez of Mr. Fuchs and Mr. Tracy 21

Cross Examination by Mr. Stamets 22

Statement by Mr. Cole 31

Questions by Mr. Chavez 32

Recross Examination by Mr. Stamets 34

E X H I B I T S

Applicant Exhibit One, Map	6
Applicant Exhibit Two, Structure Map	6
Applicant Exhibit Three, Summary	7
Applicant Exhibit Four, Cross Sections	9
Applicant Exhibit Five, Log	11
Applicant Exhibit Six, Summary	14
Applicant Exhibit Seven, List of wells	15
Applicant Exhibit Eight, Pressure Data	15
Applicant Exhibit Nine, Pressure Data	15
Applicant Exhibit Ten, Pressure Data	15
Applicant Exhibit Eleven, Tabulation	17
Applicant Exhibit Twelve, Sketch	19

MR. STAMETS: We'll call next Case 7300.

MR. PEARCE: Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

MR. BATEMAN: Mr. Examiner, I'm Ken Bateman, with White, Koch, Kelly, and McCarthy, appearing on behalf of Dome Petroleum Corporation, the applicant.

I have two witnesses.

MR. STAMETS: Any other appearances in this case?

(Witnesses sworn.)

MR. BATEMAN: Mr. Examiner, before we begin, I have given you a copy of the documented evidence we intend to introduce. Some of the exhibits, specifically Exhibit Two, I believe, and Four A and B, are reduced and I have larger copies here, which I will refer to.

MR. STAMETS: Do you happen to have one extra set of exhibits --

MR. BATEMAN: Yes, sure.

MR. STAMETS: -- for Mr. Chavez there? Thank you.

MR. CHAVEZ: Thank you.

MR. BATEMAN: Also Exhibit Five, which is a type log.

MICHAEL FUCHS

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you state your full name, please, and place of employment for the record?

A. Michael Fuchs. I'm employed as an exploration geologist at Dome Petroleum Corp.

Q. Have you previously testified before the Commission?

A. No.

Q. Would you give a resume, then, of your educational background and your work experience in the petroleum industry?

A. I have a Bachelor's from the University of Denver in geography, minor in geology and anthropology. Subsequently spent three years with Colorado School of Mines; fulfilled the requirements for a Bachelor of Science in geological engineering; applied for the Masters program in

geological engineering and completed one year of course work.

Q. And have you been employed as a geologist then in the petroleum industry?

A. Yes. I spent six months after that at Trend Exploration as an exploration geologist and two -- I've spent my last two years with Dome Petroleum as an exploration geologist.

Q. In your employment with Dome Petroleum have you become familiar with the application which is being heard today, as well as the area in question?

A. Yes, I have.

Q. Have you actively worked in that area?

A. Yes, I have.

MR. BATEMAN: Mr. Examiner, are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q Would you refer, please, to what's been marked as Exhibit One and Two and state what Dome seeks by its application today?

A. Well, Exhibit One is an index map showing the relative location of the Rusty Chacra area. It's approximately six miles south of the town of Counselor in Sandoval County, New Mexico. It includes all or portions of Townships 22 North, 6 West and 7 West, and 21 North, 5 West,

6 West, and 7 West.

I'd like to enter into the record that there's a mistake on this index map and that the exact boundary of the proposed tight gas area is shown on Exhibit Two, if you would turn to it.

Exhibit Two is a structure contour map on top of the Chacra producing zone. It's done on a contour interval of 50 feet. It shows monoclinal dip down into the basin to the northeast.

It also shows all wells in the area and cross sections lines A-A' and B-B'.

Q. The wells shown on the exhibit tested the Chacra in each case?

A. Yes. Yes, they do.

Q. Okay.

A. Okay. If you would turn to Exhibit Three, this is a summary of the geology. Gas production in the area is from build-up of transitional shaly sands and siltstones, which are interpreted to be of a pro-delta low energy origin.

Sandstones are gray to light gray, fine grained, silty, shaley, and slightly to moderately calcitic.

The fine graned and clay filled nature

of the sands results in low porosity and permeability and commercial production, when obtained, is only achieved through extensive fracturing and treatment of the formation.

Structural dip is to the northeast at about 100 feet per mile and is of little consequence since this is a stratigraphic trap. The productive zone, which is most commonly been called the Chacra or the La Ventana, is a time stratigraphic equivalent of the upper unnamed tongue of the Cliffhouse transitional sandstone. This nomenclature is derived from correlating to sections done by James E. Facet, a paper that he gave on Cliffhouse sandstone in 1977, New Mexico Geologic Society Guidebook No. 3.

In New Mexico Order No. 5459 the Chacra producing interval is defined as the interval in the Lewis shale extending from the Huerfanito bentonite bed to about 750 feet below the bed.

In our designated proposed area the top of the Chacra producing zone is about 110 feet below the Huerfanito bentonite. The producing zone is approximately 300 feet thick and about 200 feet below this -- this zone are some lower sands which have not been tested in any of the wells and for which we are not applying for tight gas status.

So just to clarify, this request for gas tight sand designation is for the uppermost sands below the

Huerfanito bentonite.

At this point I would also like to explain that the basis for the boundaries of the proposed tight gas sand area are based on both stratigraphic data and production data.

If you will turn back to Exhibit Two for reference, the southwest boundary is a stratigraphic boundary, in which the sands and silts, sands and silts show up. This can be seen on Section B-B' the gamma ray and porosity curves on B-B' show this quite well when you look at them in detail.

To the northeast there is a distinct gas/water contact which runs along the approximate area boundary. This contact was established by examination of the resistivity curves of the wells in the area and is borne out by production testing the area. The wells completed in or close to the edge were wet and/or produced a lot of water and little gas.

To the northwest and southeast the wells tighten up completely and there is again a stratigraphic boundary where the sands and siltstones shale out.

If you'll turn to Exhibits Four-A and Four-B, they are the cross sections, these sections show gamma ray and porosity curves. They also show perforations

and treatments and resulting IP's in the wells that produced or were completed in the Chacra.

An in depth study of all wells in the area showed minimum productive parameters of 10 ohms and 10 percent resistivity. Anything less than that did not appear to give up gas.

Looking at Section B-B', which is Exhibit Four-B, the first well on the section, the Filon Navajo Allotted 26 No. 1, you can -- looking across to the next well on the section, you can see that the Filon well tightens up. Since this is such a shaley zone to start with, this tightening up is only seen after detailed looking and counting of the sands, and looking at the gamma ray and porosity curves.

On this section you will also notice the Sun Oil El Paso Federal No. 1 has plenty of porosity but the resistivity was below 10 ohms throughout and completion testing in other wells indicates that this would have been wet.

Section A-A', which runs down the length of the area, actually does not go out of the area but in -- once again, in studying all the logs in the area the wells outside of the area do not meet the 10 ohms, 10 percent resistivity cutoff that were established. This is a -- you would count the net sand that it's a general sort of a thing,

you would get a few small streaks, stringers, greater than that, but if you compare -- if you look at Section A-A', which basically runs through the meat of the thing, you can see the zones, particularly the ones that we perforated, had porosities greater than 10 percent. This was not true of wells outside of the area.

Going to Exhibit Number Five, which is the type log, this simply shows the shaliness of the zone and low porosities, and that's about all that that's to show.

Q. Mr. Fuchs, is there any significant difference in the sand as reflected in these logs across the area in question?

A. There's not much difference at all, no, until you get out of the area and then in a detailed count of net sand, based on porosity and resistivity cutoffs, the thing does appear to tighten up.

Q. In your opinion are the logs of the wells as represented here representative of all the productive Chacra wells in the area in question?

A. Yes, they are.

Q. In your opinion, then, is this area recommended, then, for tight formation designation?

A. Yes, it is.

Q. Were Exhibits One through Five prepared

by you or under your direction?

A. Yes, they were.

MR. BATEMAN: Mr. Examiner, I offer at this time Exhibits One through Five.

MR. STAMETS: These exhibits will be admitted.

MR. BATEMAN: I have no further direct, at this point.

MR. STAMETS: Are there questions of this witness?

CROSS EXAMINATION

BY MR. STAMETS:

Q. Okay, the only question I can think of right now concerns Exhibit Five.

You have the top of the Chacra zone marked there. Is the base of the zone represented on this exhibit?

A. Yes, it is. Well, the base of what we're calling the possible productive zone is, and I would say it's at around 2260. If you look, it's shaled up completely and the Chacra zone, as I stated in here, as defined by New Mexico, is an interval 750 feet below the Huerfanito bentonite. The interval we're interested in, the interval

that is productive here, starts at approximately 100 feet below the Huerfanito bentonite marker, then, and goes for approximately 250 feet.

Q. Okay.

MR. STAMETS: Well, I'll have to reserve any additional questions until we hear the next witness.

MR. BATEMAN: Fine. All right. Call my next witness, please.

KEVIN TRACY

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you state your full name and place of employment for the record, please?

A. Kevin Tracy. I'm Senior Reservoir Engineer for Dome Petroleum.

Q. Have you previously testified before the Commission?

A. No, I haven't.

Q. Would you state, then, for the record your educational experience?

A. I received a Bachelor's and a Master's in engineering from Rice University. I had five years experience with Shell Oil Company as a reservoir engineer and for the past year have been employed by Dome Petroleum as a Senior Reservoir Engineer.

Q. In your employment with Dome Petroleum Corporation have you become familiar with the -- today's application or with the area in question?

A. Yes, I have.

Q. Do you have direct responsibility for it?

A. Yes, I have.

MR. BATEMAN: Mr. Examiner, are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q. Mr. Tracy, would you refer to what you've marked, or what I've marked as Exhibit Six and review the data which is indicated there?

A. Exhibit Six is a summary of the reservoir data for the application area for the Chacra formation, and of particular importance here is the average permeability of .07 millidarcies; unstimulated flow rate, too small to measure; and average flow rate after fracture stimulation of 594 Mcf. Also the crude oil production is none in the area.

Q. All right, would you proceed, then, with

Exhibits Seven through Ten and state how the averages were obtained?

A. Okay. Exhibit Seven is a list of wells within the application area that have tested the Chacra formation. This exhibit shows the well name, operator, location, spud date, the depth to the top of the Chacra, any completion interval, and average production rate after fracture stimulation and a 3-hour potential test.

It also shows the well status for each of the wells.

We've asterisked the wells that would qualify for the 107 incentive pricing by spud date next to the spud date column.

Okay, on the previous exhibit the depth to the top of the Chacra came from an average of the data shown in Exhibit Seven; also, the after stimulation rate was the average of these numbers shown here.

Q. For the record, would you tell the Examiner whether there's a market for the gas now available from this area?

A. At the present time there's approximately fourteen wells producing. The remainder of all these wells are shut in, waiting on a gathering system. We have a gas contract for our wells in the area but no hookups yet.

Q. What kind of stimulation procedures have been followed generally in this area?

A. The standard completion practice is to perforate the well, immediately acidize, and follow with a fracture stimulation treatment.

Q. Has that been done then in all cases?

A. Every one of these wells has been fracture stimulated with jobs of varying sizes and varying types.

Q. All right, then, would you proceed then with Exhibits Eight, Nine, and Ten?

A. Exhibits Eight, Nine, and Ten illustrate pressure build-up data obtained for three wells within our application area.

I might start at Exhibit Eight. 8-A shows the Horner plot for the Chase Rusty Federal No. 4, and from Exhibit 8-A and 8-B we're able to determine what part of the data represents the Horner straight line and are able to calculate in situ gas permeability for this well at .13 millidarcies.

Exhibit Nine A and Nine B show the same type of information obtained for the Dome Navajo 20-22-7 No. 1, in which an in situ permeability to gas of .047 millidarcies was obtained.

Similarly, Exhibit Ten A and Ten B show

the Horner plot and calculation of permeability of .03 millidarcies for the Dome Federal 19-22-6 No. 1.

Q. Mr. Tracy, do you believe that these wells are -- as shown on Exhibits Eight, Nine, and Ten, are representative of the wells in the area included in the application?

A. Yes, I do. These three wells are located in the center of the application area and, if anything, they represent the better part of the reservoir.

Q. Is a Horner plot a standard in the industry?

A. Yes, it is.

Q. All right. Would you proceed, then, with Exhibit Number Eleven?

A. If I can back up just once, the permeability numbers shown on these Horner plots is where the .07 millidarcy average for the area was obtained by averaging those three wells.

Exhibit Eleven shows the nine wells within our application area that we're sure had fair tests of an unstimulated flow rate. By a fair test I mean that the well was swabbed down after perforating or after acidizing. The standard practice on all the other wells was to fracture stimulate them immediately after perforating. By swabbing

them down it removed any fluid column that might be holding back any gas production.

As you can see here, the - the rates of these nine wells average too small to measure and only one case was there a measurable flow rate prior to fracture stim ulation.

For comparison we show the 3-hour potential test after the farcture treatments for the same wells.

Q How does the flow rate for the one well that did produce compare to the limit in the regulations?

A. It's below the guideline for this depth. The guideline at this depth is 59 Mcf per day against atmospheric pressure and certainly an average of these is a rate too small to measure.

Q So your conclusion is, I take it then, the average unstimulated flow rate is too small to measure?

A. Yes.

Q And that you found no crude oil production?

A. That's correct. There's no crude oil production at all in this area.

Q Are you familiar with the fresh water aquifers in the area?

A. Not directly. I've been told that the

Ojo Alamo and Pictured Cliffs might be -- might be fresh water aquifers in addition to the Fruitland.

(Thereupon conversation was had off the record.)

Q. Mr. Tracy, your conclusion is that Ojo Alamo is the fresh water aquifer in the area.

Would you proceed with Exhibit Number Twelve and tell the Examiner how the fresh water aquifers will be protected?

A. Exhibit Twelve illustrates a typical casing design for the Chacra wells in this area and of particular significance is the surface casing and production casing are both cemented to surface with generally cement return during the cementing operations and that would certainly protect any fresh water aquifers from -- from communication of other zones.

Q. Mr. Tracy, would you briefly state your opinion regarding the economics of the production of gas in this area?

A. The Chacra formation is so tight and not -- not a very prolific producer by any means, and for development to continue the 107 incentive pricing would really be required.

Q. In your opinion --

A. In my opinion.

Q. In your opinion, then, would the grant of this application prevent waste and protect correlative rights?

A. It would.

Q. Have you been in contact with other operators in the area?

A. Yes, I have. Received letters of support from several operators that I have talked to.

Q. All right, would you state for the record what you've received?

A. I have in hand a letter from Chase Development Company supporting our application; Benson Mineral Group; Jack A. Cole; Trend Exploration, Limited; Northwest Exploration Company; and have also talked to Elf Aquatain (sic); and Buckhorn, which also have working interest within our application area.

Q. Have they indicated any opposition to your application?

A. No, they indicated they were in full support of our application.

Q. Were Exhibits One -- or excuse me, Six through Twelve prepared by you or under your direction?

A. Yes, they were.

MR. BATEMAN: Mr. Examiner, I offer Exhibits Six through Twelve, and have no further direct, at this time.

MR. STAMETS: These exhibits will be admitted.

Are there some questions of this witness?

MR. CHAVEZ: Yes.

MR. STAMETS: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ OF MR. TRACY AND MR. FUCHS:

Q In Township 21 North, 5 West, are the dry holes indicated on your Exhibit Two Chacra attempts?

MR. FUCHS: No, they were Gallup tests.

MR. TRACY: Exhibit Two was prepared by Mr. Fuchs.

MR. CHAVEZ: I'm sorry, I went too far, then.

MR. STAMETS: Well, I think as long as our reporter doesn't have any trouble with that, whoever the appropriate witness is should answer this question.

And I'd like a little clarification on that, then, while we're at that point.

MR. CHAVEZ: All right.

MR. STAMETS: If you don't mind.

CROSS EXAMINATION

BY MR. STAMETS:

Q. In 22 North 7 West, there are symbols which indicate oil wells. Are those oil wells or something else?

A. (By Mr. Tracy) Those are oil and gas producers as well as oil wells in some cases. We have drilled four wells in there in the last year, partners with Tesoro. They're Tesoro wells. They're all Gallup wells. The sand is very poorly developed sand at best, and in two of them we had low GOR wells. We got about 60 barrels a day, 40 Mcf, out of two of them. They were pretty much identical.

Out of the second two, they were high GOR wells, and I think we -- they IP'd for about 20 barrels of oil a day, averaging, and about 400 Mcf.

So those are Gallup tests, Gallup producers.

Q. Does the large copy of this indicate which wells are Chacra wells and which wells are something else?

A. No, they don't.

Q. Good, that will give you something to do subsequent to the hearing, then, is to submit copies of this exhibit which clearly show which wells are Chacra wells

and which wells have tested the Chacra formation and then identify those wells producing from some other horizon.

A. Okay. I could state for sure right now for the record, though, that the black dots are Gallup producers.

Q. Okay, fine.

A. They've already been filled in, and all the open circles are -- or the open gas signs are Chacra producers.

MR. STAMETS: Frank do you have some more questions?

MR. CHAVEZ: Yes.

QUESTIONS BY MR. CHAVEZ CONTINUED:

Q. In your testimony you stated that you were not interested in including any area that might be productive, say, below this 310 feet interval that you've designated on Exhibit Five as the zone of interest for this application today.

A. That is correct.

Q. Okay. Then you want -- for the purposes of the order, then, you want the order to state that -- oh, boy, how do you word it -- that the Chacra zone for the purposes of the order would be from say the top of the Chacra

down 310, 20 feet, something like that?

A. Yes, that's fine. The reason I made that clarification in the first place is because this Chacra zone climbs throughout the section and not over our area, the area which we're designating in particular does it climb that much; maybe a total of about 30 feet, but in general, there are several silty or shaley sand zones in the designated Chacra area. I'm saying designated, designated by New Mexico by that number, I don't recall it offhand, but it was 750 feet below the bentonite. Okay, we're talking about the sandy zone that's about 100 feet below the bentonite and goes to 300 feet.

As far as I know, the next sandy zone, which is about 200 feet below that, has never been tested, and so I couldn't really say whether or not it has productive potential. I don't believe that it does.

But as far as we are concerned, the order may read just 310 feet, or whatever, being the first sands below the bentonite.

Q. Will Dome continue to drill to depths below that, the perforated interval, say -- what I'm looking at here on your Exhibit Four-A, the first well on the left, Dome Petroleum Navajo 17-22-7 No. 2, it shows the base of your perforated interval is still 150 feet above the TD of

the well.

A. Yes. We will continue to drill down there, I believe.

There was some thinking, if you'll look at the porosity curves on these logs, you'll see that below where we perforated in those wells, as matter of fact, on the Benson Federal 26-22-7 they did complete in that lowermost sand zone. If you'll notice, there are three sort of sandy zones, and in the lowermost sand zone they did complete.

Well, we have done some testing in some wells, two wells, completion testing where we selectively perforated and treated, and the C, or the lower, this lower portion here, the third sandy zone, as we call it, did not appear to give up very much gas.

Now we've only done this in two wells so we're not, you know, 100 percent sure that this is the case all the time, but we're -- I think we'll continue to drill down 300 feet through the Chacra, in the top of the Chacra.

Q. That is why you want to include that lower interval in the application today.

A. Yes, there's still probably testing yet to be done.

Q. On the wells which were plotted on the

Horner plot showing the calculations of permeability were any initial potential tests run on those wells?

A. Yes, there were. On the Horner plot itself we show a gas rate on here for instance, the Dome Federal 19--22--6 No. 1, the Q in the equation is the test rate prior to the shut-in for that well, and in this case it was 275 Mcf a day.

Q. And this is after treatment, then?

A. Yeah, it has to be after treatment because prior to treatment we could not get the wells to produce anything to get a drawdown in the reservoir pressure, to come up with this type of analysis and because it was after the treatment it also took very long shut-in times. These were run eight to ten days.

Q. Did the plots indicate any skin damage which might have shown a reduced volume without the fracture treatment?

A. I didn't show that information on here. They were negative skin, so it showed stimulation from the fracture treatment.

MR. CHAVEZ: I have no further questions

MR. STAMETS: The testimony here has been that the wells produced no crude oil. Do they produce any condensate?

A. No, they do not.

MR. STAMETS: So absolutely dry gas.

A. Yes, sir.

MR. STAMETS: Now, the -- we've been told here that all the gas wells shown on Exhibit Two are Chacra gas wells and looking at that it would appear as though each one of these wells is developing a single 160-acre pro ration unit, is that correct?

A. That is correct.

MR. STAMETS: And the -- there is no Division order relative to this area that calls for or permits an infill drilling program, is that correct?

A. To the best of my knowledge, that is correct.

MR STAMETS: Okay. From your study of the records were any of the wells cored through the Chacra section?

A. Yes, there were several cores within the area here.

MR. STAMETS: Did you review that data to see what information was given relative to permeability?

A. Yes I did review it. There are four cores that I'm aware of and I did review them for permeability data.

The permeability data that was measured on the cores was after they were cleaned and dried and were measured at surface conditions to air as a medium flowing through the core, and for that reason I did not include that information because it was not really representative of the reservoir rock at in situ conditions in the reservoir. I felt that the Horner plot better tells us what the permeability of the gas is at reservoir conditions rather than the core data.

MR. STAMETS: Did the core data show conditions very close to what you estimated here or much higher?

A. The average on the core data was about .3 of a millidarcy, compared to our .07 that we're testifying to here. In fact, two of the wells that we have these extended pressure build-up plots were wells that were cored. And we have direct comparison of core permeability to a Horner plot permeability from those two wells.

MR. STAMETS: I believe submission of that data would be most helpful to the Examiner.

A. Let me dig it out.

Okay, the four wells that have cores that I'm familiar with are the Dome Federal 19-22-6 No. 1, which had an average core permeability to air at surface con-

ditions at .324 millidarcies.

Okay, the second one is the Benson Navajo 21 No. 1, which is in Section 21 of 22 North, 7 West, the average core permeability was .209 millidarcies.

The third well is the Dome Federal 15-22-7 No. 1, with an average core permeability of .455.

And the fourth is the Dome Navajo 20-22-7 No. 1 with a core permeability of .384 millidarcies.

The first and the fourth well that I just read off to you are two of the wells with the Horner plots.

The first one, the Dome Federal 19-22-6 No. 1 for comparison had a Horner build-up plot of .04 millidarcies compared to the core permeability of .324.

The fourt one was the Dome Navajo 20-22-7 No. 1 with a Horner build-up of .05 millidarcies and the core permeability of .384.

There are papers in the literature that recognize that core permeability, especially in the tight, low permeability rock, are not particularly representative of in situ conditions and the permeability of the gas.

One major factor off the bat would be that water saturation is not taken into consideration and these tight rocks have very high water saturations and low.

low gas saturations in the reservoir.

There are just a lot of reasons that we felt that core permeabilities were not representative of the actual in situ permeability gas, which is the way the rules are written.

MR. STAMETS: Were there any drill stem tests, to your knowledge?

A. None that I'm aware of.

MR. STAMETS: Then Exhibit Number Eleven does show wells which were perforated and swabbed dry and then were these, from your examination of wells were tested at that point to see if they had any natural flow?

A. Yes, they were. Most of these wells, such as the Dome wells here, we took an extra two days of swabbing the well down and making sure we had a good, valid test at an unstimulated rate. We took an additional time and expense to gather the information for this hearing.

MR. STAMETS: And the one well on there, the Dome State No. 2 Well, the only well that showed any unstimulated production, test what may be the highest 3-hour potential after frac of --

A. Of the whole area.

MR. STAMETS: -- in any well.

A. Yes, sir.

MR. STAMETS: So do you feel that that's evidence to indicate that essentially everywhere in this area you will have too small to measure as your nonstimulated rate?

A. That's my conclusion, that this is one of the very best wells in the whole area and it even reached the requirements of the guidelines. It's below the 59 Mcf per day rate.

MR. STAMETS: Yes, sir? Would you identify yourself for the record, please?

MR. COLE: Yes, sir. My name is Jack Cole. I've drilled nine or ten wells in this area and am also included in this exhibit, and before the days we were worried about tight sand type things, a year and a half ago when I drilled my Alamos Canyon No. 2, we -- we swabbed it down also to see if we would get a -- because it was the first well I completed down there, to see what kind of natural flow it would get. We did not test it over a signi-ficant period of time, but we had no flow rate, no, not even a fume, and we went ahead and fraced and that well made just a shade under a million on initial potential.

MR. STAMETS: Thank you, Mr. Cole, we appreciate that.

Referring to Exhibit Twelve you indicated

that this type of completion process would protect any fresh water in the area. Is this the type of completion that State and Federal regulations and processes is requiring for the area?

A. To the best of my knowledge it meets all State and Federal requirements in the area.

MR. STAMETS: Are there other questions? Mr. Chavez?

MR. CHAVEZ: I have one more question for the witness.

QUESTIONS BY MR. CHAVEZ:

Q. On this Horner plot, Exhibit Nine-A, for Gulf Navajo 20-26-7 No. 1, he shows an "H", which is the thickness of the sand, that's what's represented, isn't it?

A. Yes.

Q. Of 100 feet. Then on Exhibit Number Seven, page four, in that well we show a sand thickness or a perforation -- completion interval that's only 33 feet thick, and by using that figure we get a "K", or permeability, of .1424. Is there one reason that --

A. Well, the 100 feet shown on our Exhibit Nine-A, represents calculated feet of sand that we felt we had open to production in the well, although only 33 feet

of perforations were there, the fracture stimulation opened up the whole interval.

Q. Do you have any tracers or any temperature surveys that show that?

A. Not on this particular well. We have done radioactive tracers surveys after fracs to show what -- what interval was -- how the fracture height was growing in these wells, and in most cases it was all of these permeable sands were opened up to production by means of the fracture stimulation.

Q. Is it normal to expect a horizontal fracture in these kinds of sands?

A. No, it's a vertical fracture.

Q. I'm sorry, a vertical fracture?

A. Yes.

Q. And this 100 feet is representative of the type of fractures that are opened up in any of these Chacra wells with a 33 foot perforated interval?

A. Well, the perforated interval varies a lot from well to well. I feel it is representative that this is -- these are the porous sands that we counted off of the logs that we felt were opened up by the fracture treatment.

MR. CHAVEZ: I have no further questions.

RECROSS EXAMINATION

BY MR. STAMETS:

Q. What is the typical fracture treatment, then, or the cost of said treatment?

A. Well, a typical size -- different operators have different approaches to this. Ours have been recently foam fracture jobs with 30 to 90,000 pounds of sand, depending on how much interval we have perforated. That's -- that range is probably typical.

The cost would be anywhere from $15 to $40,000, depending on how large a frac job you had planned for the well, and it's definitely a significant, very significant, part of the well cost.

Q. What do these wells cost in this area now?

A. Between $100 and $150,000 per well, including frac, and any production equipment.

Q. What types of reserves do you feel are being developed on a per well basis?

A. Well, that's a tough question right now because we don't have very much production history on of the wells. They're all shut-in waiting on pipeline.

We're hoping to recover on the order

of -- I'm trying to remember -- 200-million cubic feet per well.

I might point out that there are some producing wells in the area and their ultimate recovery is going to be much less than that. Currently they're averaging about 10 Mcf per day per well after three years of production.

MR. STAMETS: Any other questions of the witness? Either witness? They are both excused.

Anything further in this case?

The case will be taken under advisement.

(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 CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. ____, heard by me on _____ 19____.

_____, Examiner
Oil Conservation Division

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 3A
CASE NO. 7300
Submitted by APPLICANT
Hearing Date 10-21-81

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Chace Rusty Federal #4

Attached is a copy of the field data reported for an extended pressure buildup test on this well. Gas rate, time, and casing pressures were used in the evaluation of kh for this well. The casing pressure was corrected to bottom hole pressure at the midpoint of the perforated interval. (Roughly casing pressure plus 15 psi for the column of gas in the wellbore).

Also attached is a copy of a one point test and calculation of absolute open flow potential. From this form the reservoir temperature of 92 degrees F and gas gravity of .626 was obtained. Using this information the following variables were obtained for use in the calculation of kh, the permeability thickness and then k, the insitu permeability to gas.

T = Reservoir temperature 92 degrees F + 460 = 552 degrees R

μ = Viscosity of gas at average pressure conditions. Average pressure was obtained by averaging the flowing pressure and the final shut in pressure $\frac{245 + 519}{2}$ = 380 psi

Fig. D.27 page 234 from Advances in Well Test Analysis by Robert C. Earlougher Jr. was then used to get a gas viscosity of .012 cp.

z = real gas deviation factor. Fig. D.3 page 223 of Advances in Well Test Analysis by Robert C. Earlougher Jr. was used to get pseudo critical temperature

and pressure of 367 degrees R and 670 psia respectively. Pseudo reduced pressure and temperature were then calculated as follows:

$$Ppr = \frac{380}{670} = .567$$

$$Tpr = \frac{552}{367} = 1.5$$

Then using Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr. a real gas deviation factor of .94 was obtained.

q = Producing gas rate in MCF/Day 627 MCF/D is the last rate measured before the well was shut in.

t = Production time in hours = 8 hrs, t = cumulative production during the test divided by final rate times 24 hrs/day.

Δt = Shut in time in hours.

h = Thickness of pay contributing to production = 52'. This number was determined from porosity logs run in the well using an 8% porosity cut off and subtracting any shale breaks.

MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL

Revised 4-1-65

Type Test: [X] Initial [ ] Annual [ ] Special				Test Date: 11-20-75	
Company: Chace Oil Co.			Connection: Waiting on Pipeline		
Pool: Undesignated			Formation: Chacra		Unit
Completion Date: 10-26-75	Total Depth: 1974		Plug Back TD: 1943	Elevation: 6904 GR	Farm or Lease Name: Rusty Federal
Csg. Size: 4.500 / Wt.: 10.50 / d: 4.052 / Set At: 1972			Perforations: From 1758 To 1801		Well No.: 4
Tbg. Size: 1.900 / Wt.: 2.90 / d: 1.610 / Set At: 1803			Perforations: From Open To Ended		Unit: M / Sec.: 13 / Twp.: 22N / Rge.: 7W
Type Well – Single – Bradenhead – G.G. or G.O. Multiple: Single			Packer Set At: None		County: Sandoval
Producing Thru: Tubing	Reservoir Temp. °F: 92 @ 1915		Mean Annual Temp. °F: --	Baro. Press. – P_a: 12.0	State: New Mexico
L: 1803 / H: 1803 / Gg: 0.626	% CO_2: --	% N_2: --	% H_2S: --	Prover: --	Meter Run: -- / Taps: --

FLOW DATA					TUBING DATA		CASING DATA		
NO.	Prover Line Size	X Orifice Size	Press. p.s.i.g.	Diff. h_w	Temp. °F	Press. p.s.i.g.	Temp. °F	Press. p.s.i.g.	Temp. °F	Duration of Flow
SI						480		490		10 da
1.	3/4" THC				60	106		230		3 hr
2.										
3.										
4.										
5.										

RATE OF FLOW CALCULATIONS

NO.	Coefficient (24 Hour)	$\sqrt{h_w P_m}$	Pressure P_m	Flow Temp. Factor Ft.	Gravity Factor Fg	Super Compress. Factor, Fpv	Rate of Flow Q, Mcfd
1	12.3650		118	1.0000	0.9759	1.0000	1,423
2.							
3.							
4.							
5.							

NO.	P_t	Temp. °R	T_t	Z
1.	--			
2.				
3.				
4.				
5.				

Gas Liquid Hydrocarbon Ratio _____ Mcf/bbl.
A.P.I. Gravity of Liquid Hydrocarbons _____ Deg.
Specific Gravity Separator Gas _____ XXXXXXXXXX
Specific Gravity Flowing Fluid _____ XXXXX
Critical Pressure _____ P.S.I.A. _____ P.S.I.A.
Critical Temperature _____ R _____ R

RECEIVED
NOV 26 1975
OIL CON. COM.

P_c 502 P_c^2 252,004

NO	P_t^2	P_w	P_w^2	$P_c^2 - P_w^2$
1		242	58,564	193,440
2				
3				
4				
5				

(1) $\frac{P_c^2}{P_c^2 - P_w^2} = 1.3028$ (2) $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n = 1.2521$

AOF = Q $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n = 1,782$

Absolute Open Flow 1,782 Mcfd @ 15.025 | Angle of Slope θ _____ | Slope, n _____

Remarks: _____

Approved By Commission:	Conducted By:	Calculated By:	Checked By:
		Ewell N. Walsh	

KE SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

m=924,985 PSI^2/cycle

$$kh=\frac{1637(\mu)(z)(T)(q)}{m}$$

$$=\frac{1637(.012)(.94)(555)(627)}{924,985}$$

$$=6.95$$

h=52' k=.13

p^2 X10^{-3}

280
260
240
220
200
180
160
140

1.0 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ (t=8hrs.)

EXHIBIT 8A

K&E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

CHASË/RUSTY/FED. #4

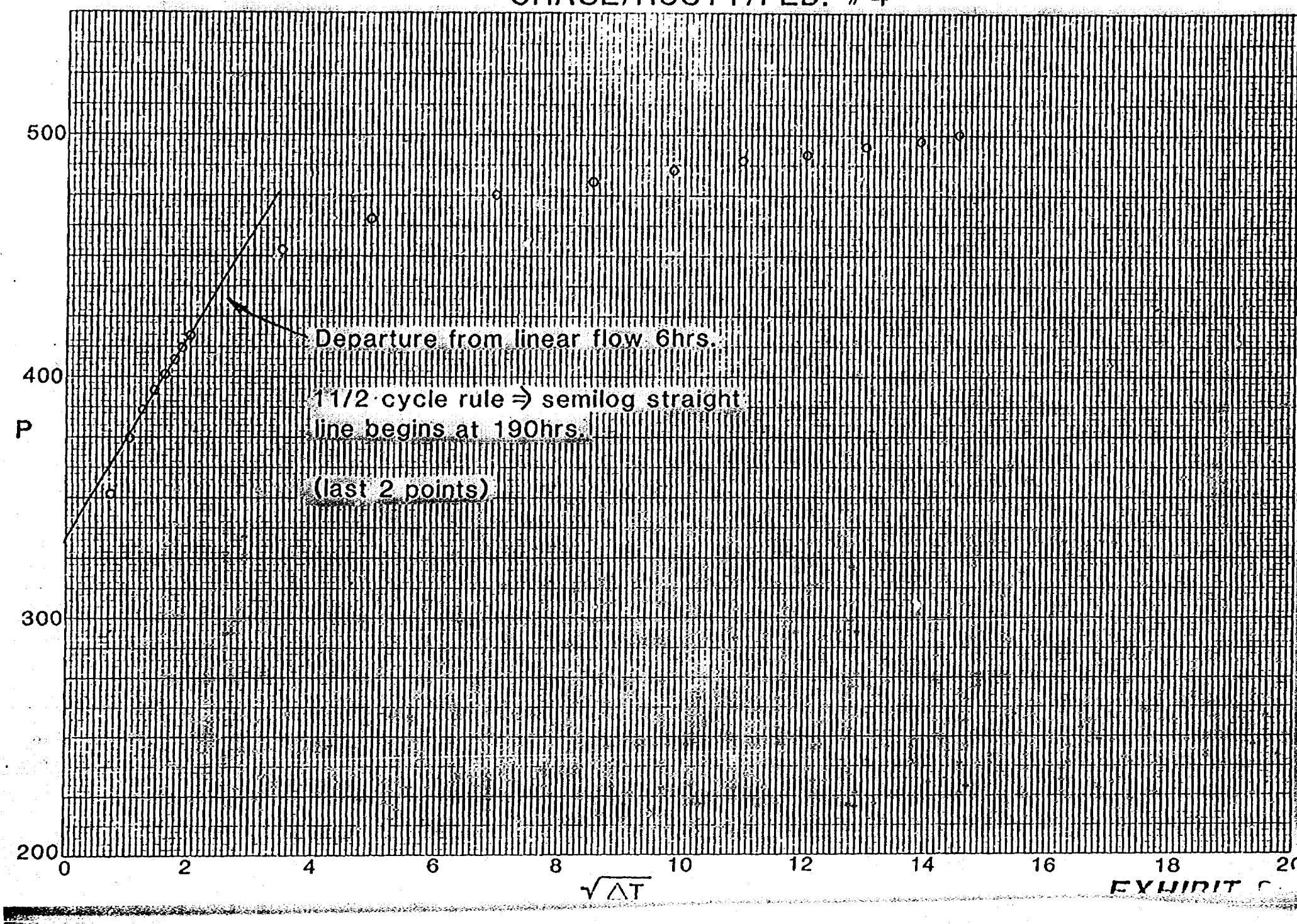


EXHIBIT C

RUSTY FEDERAL NO. 4

SANDOVAL COUNTY, NEW MEXICO

800'S, 800'W, Sec. 13, T-22-N, R-7-W

DATE	TIME		CSG. PRESS. PSIG	TBG PRESS. PSIG	RATE MCF/D	VOL. TIME MCF	CUM. VOL. MCF	REMARKS
11-05-75	09:15		492	492				SI PRESSURE, WELL ON, 2" CRITI
	09:30		468	464	360	3.75	3.75	FLOW PROVER, 3/16" PLATE
	09:45		457	454	352	3.66	7.41	
	10:00		450	447	347	3.61	11.02	
	10:15		444	441	342	3.56	14.58	CHANGED TO A 1/4" PLATE
	10:30		425	418	579	6.03	20.61	
	10:45		416	409	567	5.91	26.52	
	11:00		408	400	555	5.78	32.30	
	11:15		402	394	547	5.70	38.00	CHANGED TO A 3/8" PLATE
	11:30		339	308	943	9.82	47.82	
	11:45		318	286	878	9.15	56.97	WELL STARTED MAKING A FINE SPI OF WATER
	12:00		304	284	871	9.08	66.05	
	12:15		291	262	806	8.39	74.44	CHANGED TO A 1/2" PLATE
	12:30		244	185	1042	10.86	85.30	
	12:45		220	167	947	9.87	95.17	
	13:00		206	156	888	9.25	104.42	
	13:15		206	132	761	7.92	112.34	WELL STARTED MAKING MEDIUM SP OF LIQUIDS
	14:15		237	121	703	29.27	141.61	
	15:15		238	115	671	27.95	169.56	
	16:15	PMT+1	238	110	644	26.85	196.41	
	17:15		235	106	627	26.12	222.53	WELL SI FOR BU
.5	17:45	16.5	335	334				
1.0	18:15	8.75	358	357				
1.5	18:45	6.17	370	370				
2.0	19:15	4.88	378	378				
2.5	19:45	4.1	385	385				
3	20:15	3.58	391	391				
3.5	20:45	3.21	396	396				
4	21:15	2.94	401	401				
11-06-75	05:15	1.65	436	436				
24	17:15	1.32	454	454				

PASO NATURAL GAS COMPANY

Memorandum

To: Mr. Richard F. Lemon, Reservoir

From: Production

Date: November 18, 1975

Place: Farmington, NM 87401

Re: Special Test on Chace Oil Company Well

A build-up test was continued for an additional seven (7) days with a pressure recorder attached to the casing and tubing on the Rusty Federal No. 4. The results are listed below.

Date		Time	Pressure Casing PSIG		Tubing PSIG
11-07-75	1.161	1715	*459	480	*459
11-08-75	1.108	1715	464	485	464
11-09-75	1.081	1715	469	490	469
11-10-75	1.065	1715	473	495	473
11-11-75	1.054	1715	476	498	476
11-12-75	1.046	1715	479	501	479
11-13-75	1.040	1715	482	504	482
11-14-75	1.037	1030	*484	506	*484

*Denotes Dead Weight Pressures

The recorder was removed and the test discontinued.

H. E. McAnally
H. E. McAnally
Senior Well Test Engineer

dsc

cc: Messrs. R. F. Lemon
G. Lippman
R. McCary-Chace
R. Ullrich
Test Data Section--Reservoir
File

SW/SW
Sec 13
T22-R7

1700

CHASE
RUSTY
FED. #4

1738+5178
Chacra A

1800

1820+5096
Chacra B

Caliper Curve

Gamma Ray

1872

43' → 10%
9' → 14%

BULK DENSITY

11'

4'

52'

31' → 10%
7' → 14%

COMPENSATION

POROSITY

using the technique described in Ref. 4. (In Ref. 4, Table 5 is used for hydrometer measurements at other than 60 °F; Table 7 allows correction of volume at a given temperature to volume at 60 °F.) Fig. D.2 applies to bubble-point liquids, again using the specific gravity corrected to 60 °F. The bubble-point pressure at 60 °F should be determined in the laboratory.* Fig. D.3 applies to condensate well fluids and natural gases; knowledge of the gas gravity is required to use Fig. D.3.

T_{pc} and p_{pc} are normally used to estimate the pseudoreduced temperature and pressure:

$$T_{pr} = \frac{T}{T_{pc}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (D.3)$$

and

$$p_{pr} = \frac{p}{p_{pc}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (D.4)$$

where

T = temperature of interest, °R
p = pressure of interest, psia.

Note in Eqs. D.1 through D.4 that temperature must be absolute temperature and pressure must be absolute pressure.

Since many correlations in this appendix use specific gravity or API gravity, it is worthwhile to restate the relationship between those two quantities:

$$°\text{API} = \frac{141.5}{\gamma} - 131.5. \quad \ldots\ldots\ldots\ldots\ldots\ldots (D.5)$$

In Eq. D.5, the specific gravity, γ, must be corrected to 60 °F and atmospheric pressure.

Figs. D.4 through D.6 are Standing's[5] correlations for properties of mixtures of hydrocarbon gases and liquids. Examples of their use are shown in the figures. Standing's correlations are based mainly on the properties of California crude oils. Cronquist[6] gives correlations that may be useful for Gulf Coast oils.

Fig. D.7 is the well known chart of real gas deviation factor for natural gases. Pseudoreduced properties may be estimated from Eqs. D.1 through D.4.

*If only the value at reservoir temperature is known, Fig. D.5 may be used to estimate the 60 °F value by going vertically upward from the bubble-point pressure to reservoir temperature, horizontally left to 60 °F, and vertically downward to the estimated bubble-point pressure.

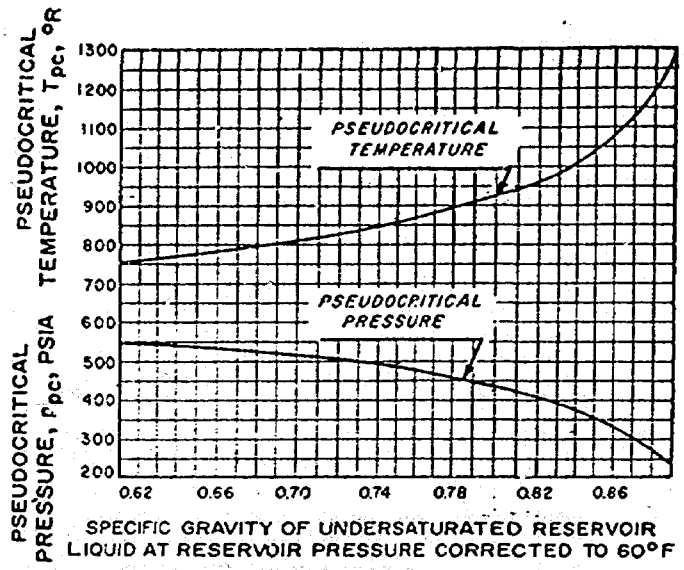


Fig. D.1 Approximate correlation of liquid pseudocritical pressure and temperature with specific gravity. After Trube.[2]

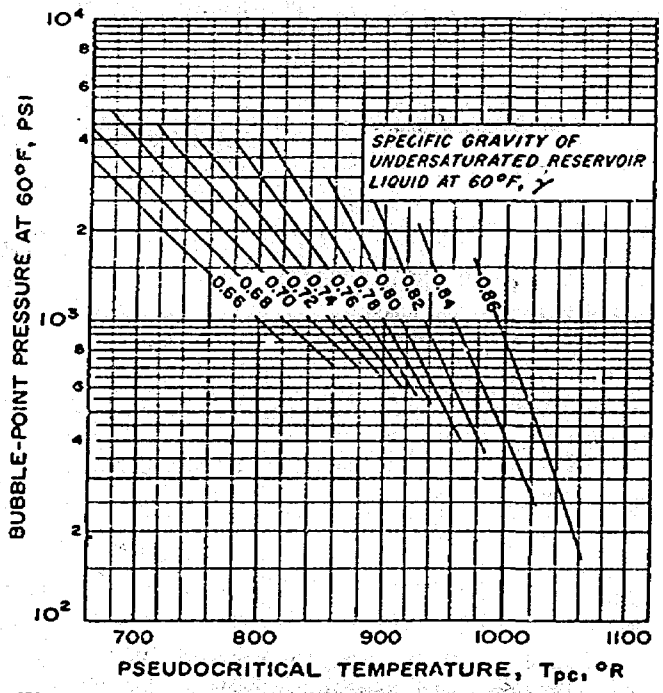


Fig. D.2 Correlation of liquid pseudocritical temperature with specific gravity and bubble point. After Trube.[2]

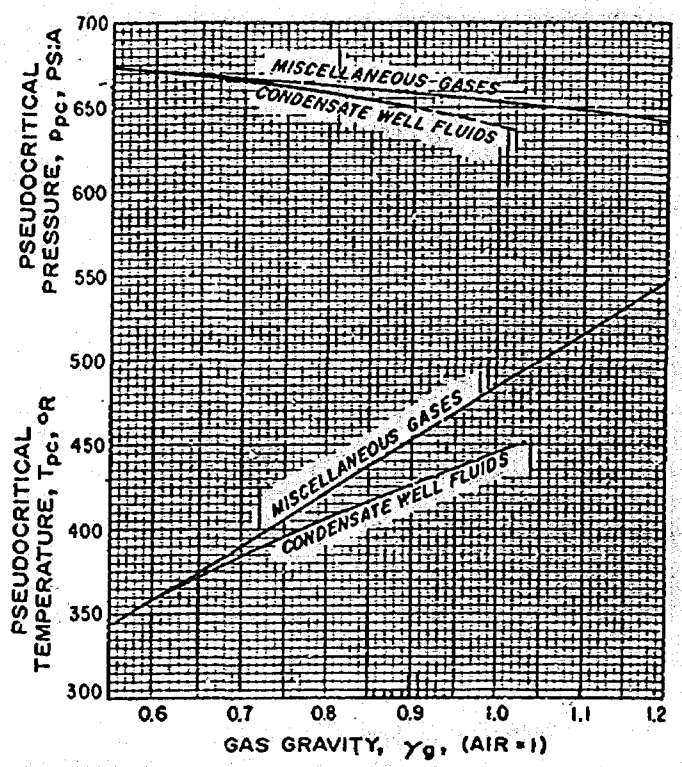


Fig. D.3 Correlation of pseudocritical properties of condensate well fluids and miscellaneous natural gas with fluid gravity. After Brown *et al.*[3]

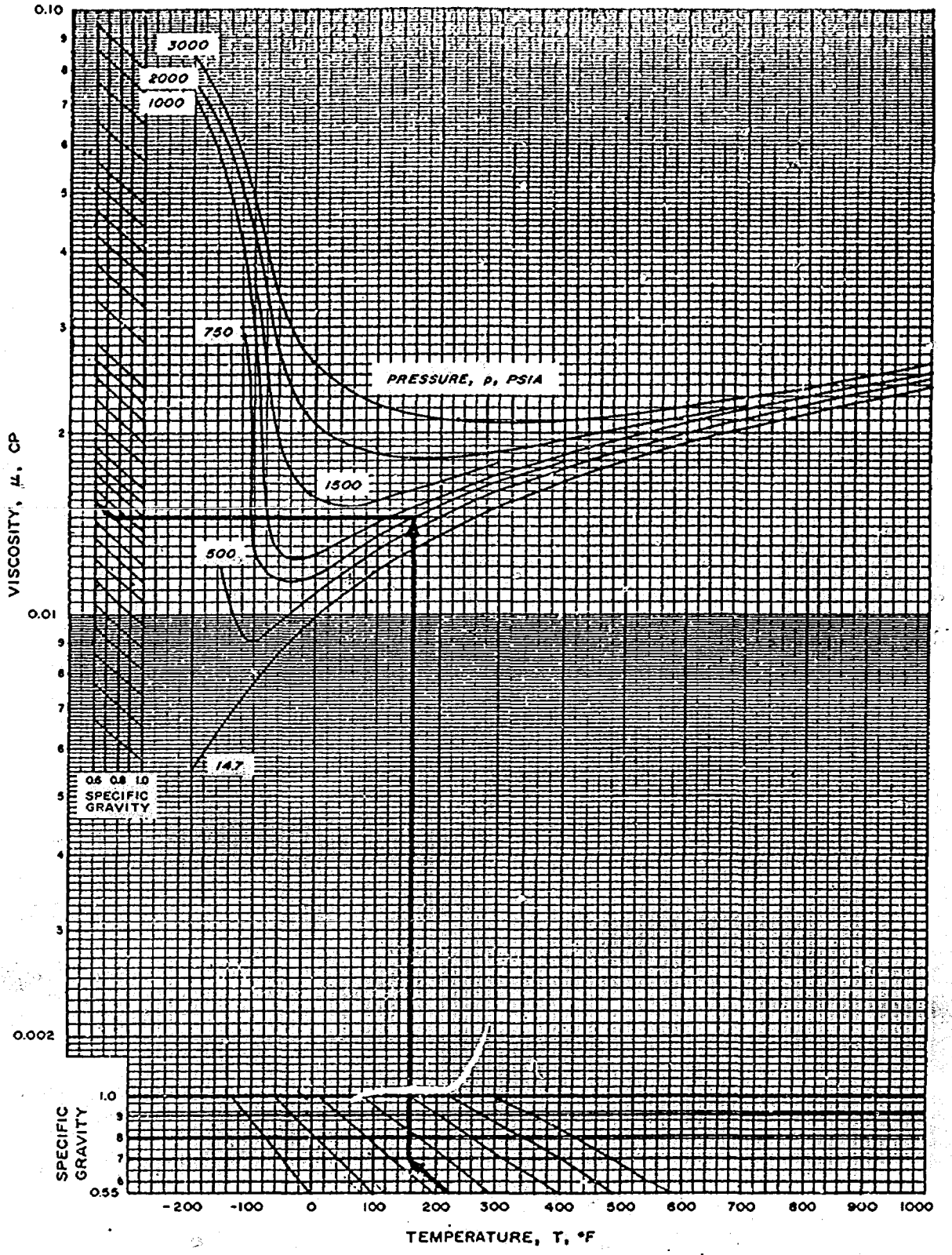


Fig. D.27 Viscosity of hydrocarbon gases.[1]

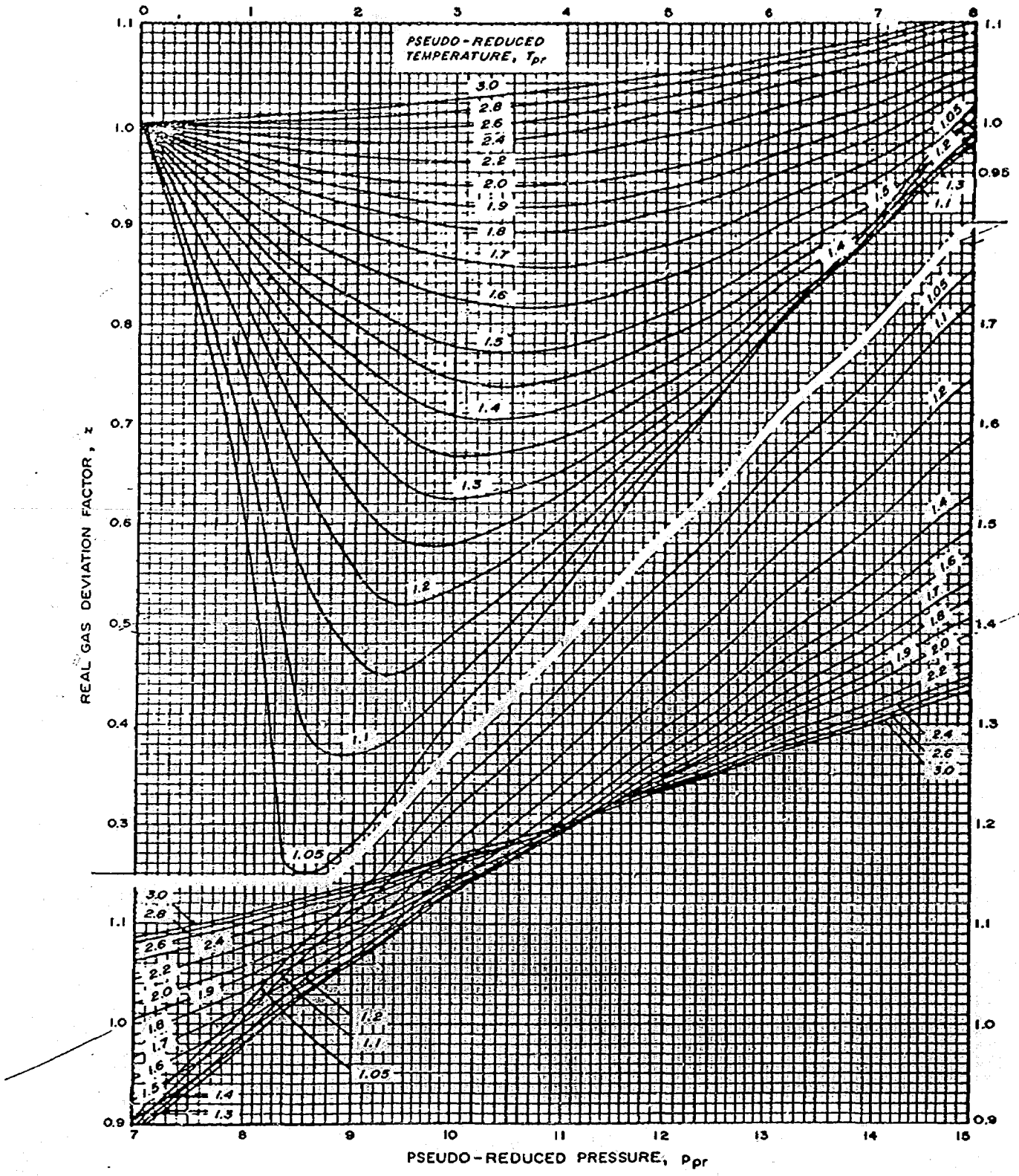


Fig. D.7 Real gas deviation factor for natural gases as a function of pseudoreduced pressure and temperature. After Standing and Katz.[7]

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 12B
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Dome Navajo 20-22-7 #1

Attached is a copy of the field data for an extended pressure buildup test for this well. Flow rates and bottom hole pressure and times were obtained from this form.

Flowing time, for the purposes of calculating superposition time in the Horner plot was calculated as follows:

cumulative production during the test divided by final flow rate times 24 = t (in hrs.) = 8.72 hrs.

A gas analysis was not available for this well so the average value for gas gravity from eight gas analysis on other Chacra wells was used. Those gas analysis are attached. This average gas gravity of .63 was used in conjuction with Fig. D.3 page 233 of Advances in Well Test Analysis by Robert C. Earlougher Jr. to get pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psia respectively. The average pressure was determined to be 362 psi by averaging the flowing pressure and final shut in pressure.

$$\frac{320 + 404}{2} = 362 \text{ psi}$$

Reservoir temperature was assumed to be the same as that recorded in the pressure buildup test in the Dome Federal 19-22-6 #1. During that test a temperature of 166 degrees F was recorded.

$$T = 166 + 460 = 626 \text{ degrees R}$$

Using this temperature and average pressure pseudo reduced temperature and pseudo reduced pressure were calculated and used with Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr.

$$Ppr = \frac{362}{670} = .54$$

$$Tpr = \frac{626}{367} = 1.7$$

$$z = .97$$

Next gas viscosity was estimated at the average pressure by using Fig. D. 27 page 234 of Advances in Well test Analysis to get

$$\mu = .0121\ cp.$$

Other variables used in the calculation of k, the insitu permeability to gas, are as follows:

q = gas rate in MCF/Day = 101 the last recorded rate before shutting in the well

Δt = shut in time, in hrs., from the field data

h = thickness of pay contributing to production = 100 feet. This number was determined by adding up the permeable zones with porosity greater than 8% as determined from a porosity log.

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: NAVAJO 20-22-7 NO. 1 Page 5 of 8

Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1500' Psig
1-23	Arrived on location							
"	shut-in	08:45				391	392	
"	Tandem insts. @ 1500'	09:40				391	392	412
"	"	10:00				391	392	412
"	Open well, 2"X1/8" CFP	10:00	0	00				
"	"	10:30	0	30				389
"	"	11:00	1	00	119	349	351	377
"	"	11:30	1	30				369
"	"	12:00	2	00	118	342	346	362
"	"	12:30	2	30				357
"	"	13:00	3	00	114	334	334	352
"	"	13:30	3	30				348
"	"	14:00	4	00	111	324	327	343
"	"	14:30	4	30				340
"	"	15:00	5	00	108	318	318	337
"	"	15:30	5	30				333
"	"	16:00	6	00	106	312	315	331
"	"	16:30	6	30				327
"	"	17:00	7	00	104	305	308	325
"	"	17:30	7	30				322
"	"	18:00	8	00	101	297	299	320
"	Shut in for build up	18:00	0	00				
"	"	18:15	0	15				331
"	"	18:30	0	30				339
"	"	18:45	0	45				345
"	"	19:00	1	00				349
"	"	19:15	1	15				352
"	"	19:30	1	30				354
"	"	20:00	2	00				358
"	"	20:30	2	30				362
"	"	21:00	3	00				364
"	"	22:00	4	00				368
"	"	23:00	5	00				371
1-24	"	00:00	6	00				373
"	"	03:00	9	00				378
"	"	06:00	12	00				382
"	"	12:00	18	00				386
"	"	18:00	24	00				389
1-25	"	06:00	36	00				392
"	"	18:00	48	00				394
1-26	"	18:00	72	00				397

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: NAVAJO 20-22-7 NO. 1 Page 6 of 8

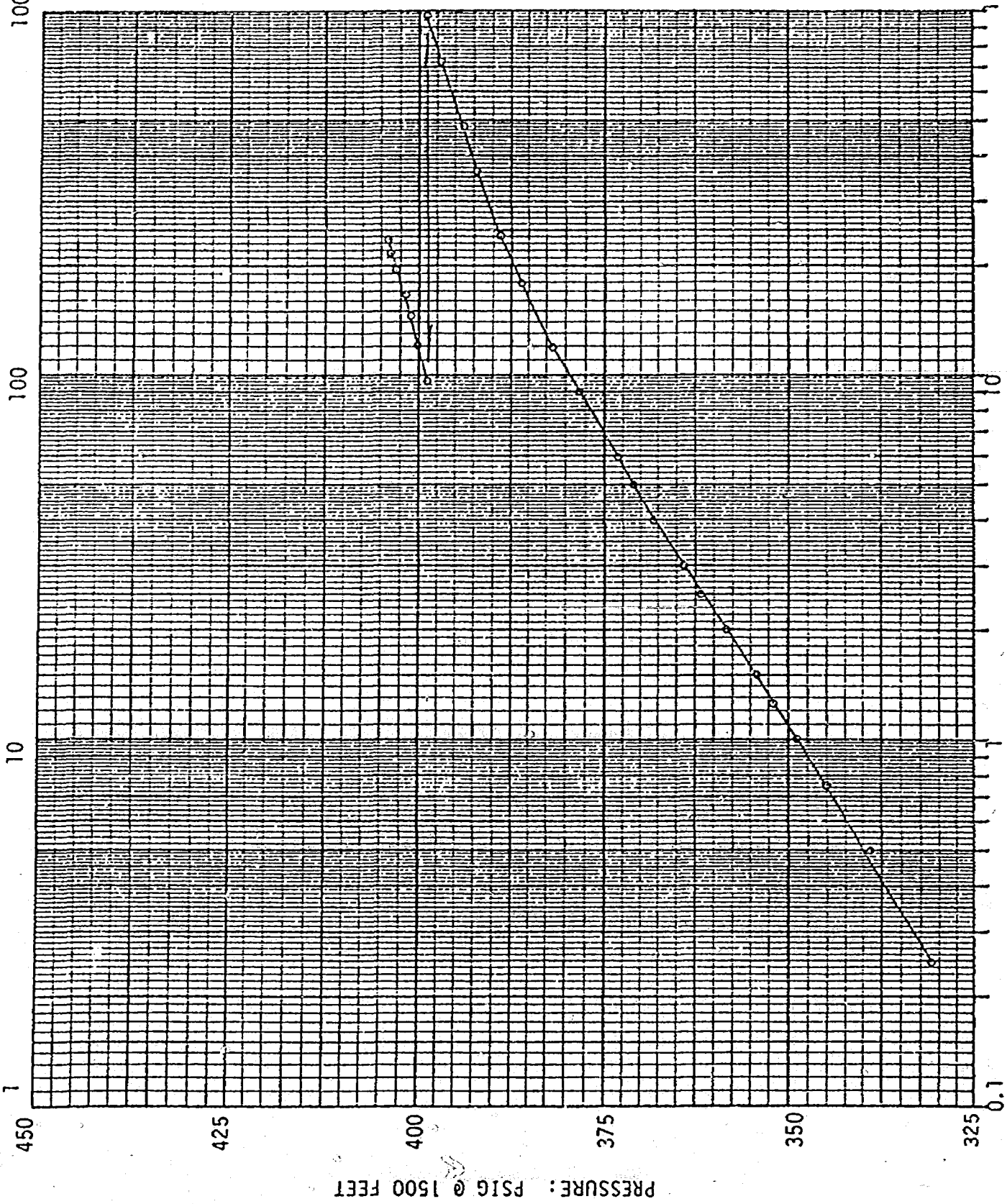
Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1500' Psig
1-27	Continued shut-in	18:00	96	00				399
1-28	"	18:00	120	00				400
1-29	"	18:00	144	00				401
1-30	"	18:00	168	00				402
1-31	"	18:00	192	00				403
2-1	"	18:00	216	00				403.5
2-2	"	13:30	235	30				404
"	Gradient Traverse	14:00	236	00		387		404

TEFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION
Well NAVAJO 20-22-7 NO. 1
Field RUSTY CHACRA
Formation CHACRA
County SANDOVAL
State NEW MEXICO



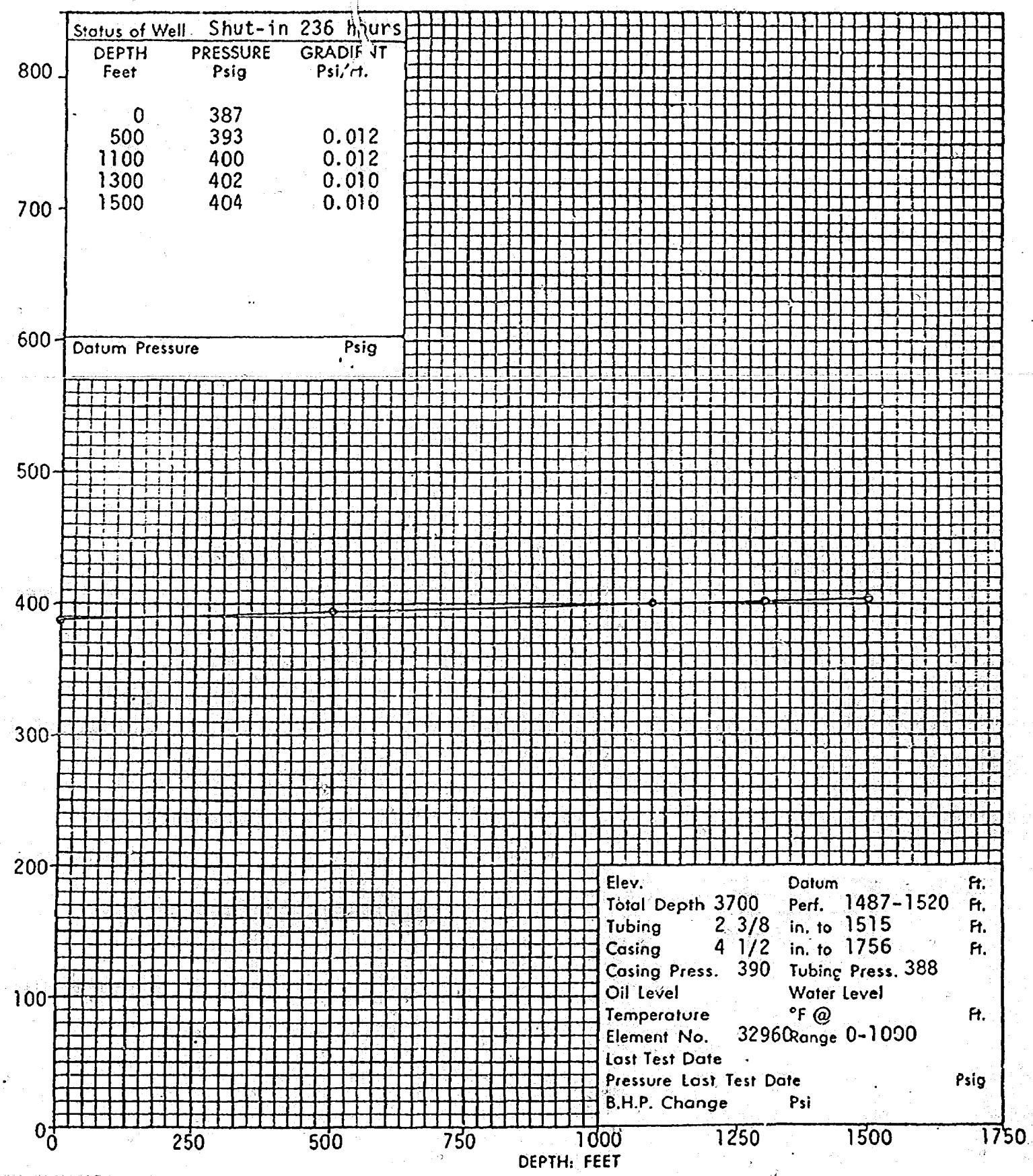
TEFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Lease NAVAJO 20-22-7 Well No. 1
Field RUSTY CHACRA County SANDOVAL State NEW MEXICO
Formation CHACRA Test Date FEBRUARY 2, 1981

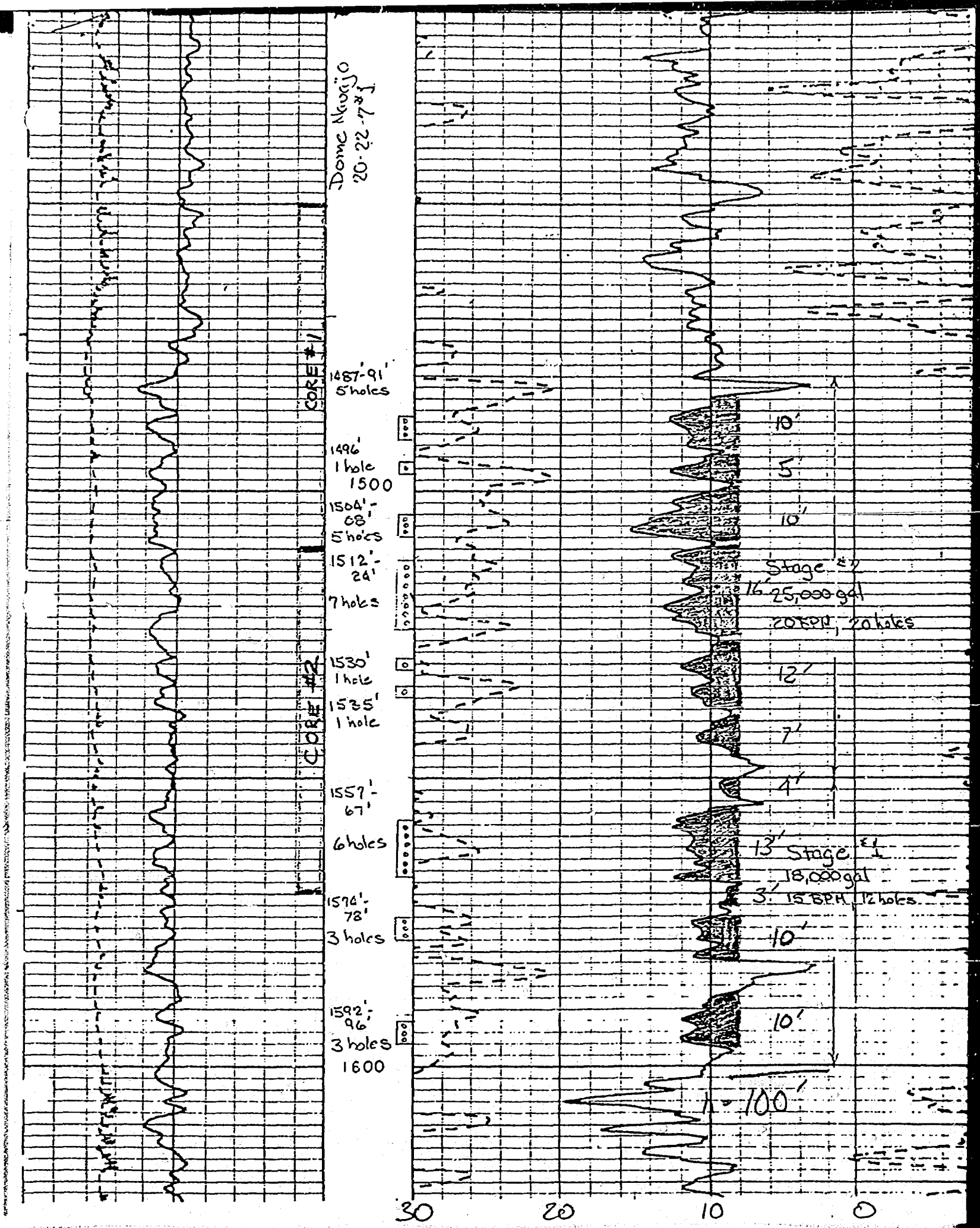
Status of Well Shut-in 236 hours

DEPTH Feet	PRESSURE Psig	GRADIENT Psi/Ft.
0	387	
500	393	0.012
1100	400	0.012
1300	402	0.010
1500	404	0.010

Datum Pressure Psig



Elev.		Datum	Ft.
Total Depth	3700	Perf.	1487-1520 Ft.
Tubing	2 3/8	in. to	1515 Ft.
Casing	4 1/2	in. to	1756 Ft.
Casing Press.	390	Tubing Press.	388
Oil Level		Water Level	
Temperature		°F @	Ft.
Element No.	32960	Range	0-1000
Last Test Date			
Pressure Last Test Date			Psig
B.H.P. Change		Psi	


Dome Mound
20-22-7 #1
CORE #1
1487'-91'
5 holes
1496'
1 hole
1500
1504'-08'
5 holes
1512'-24'
7 holes
CORE #2
1530'
1 hole
1535'
1 hole
1557'-67'
6 holes
1574'-78'
3 holes
1592'-96'
3 holes
1600
10'
5
10'
Stage #1
16' 25,000 gal
20 BPH, 20 holes
12'
7'
4'
13'
Stage #2
18,000 gal
3' 15 BPH, 12 holes
10'
10'
1" = 100'
30
20
10
0

K+E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

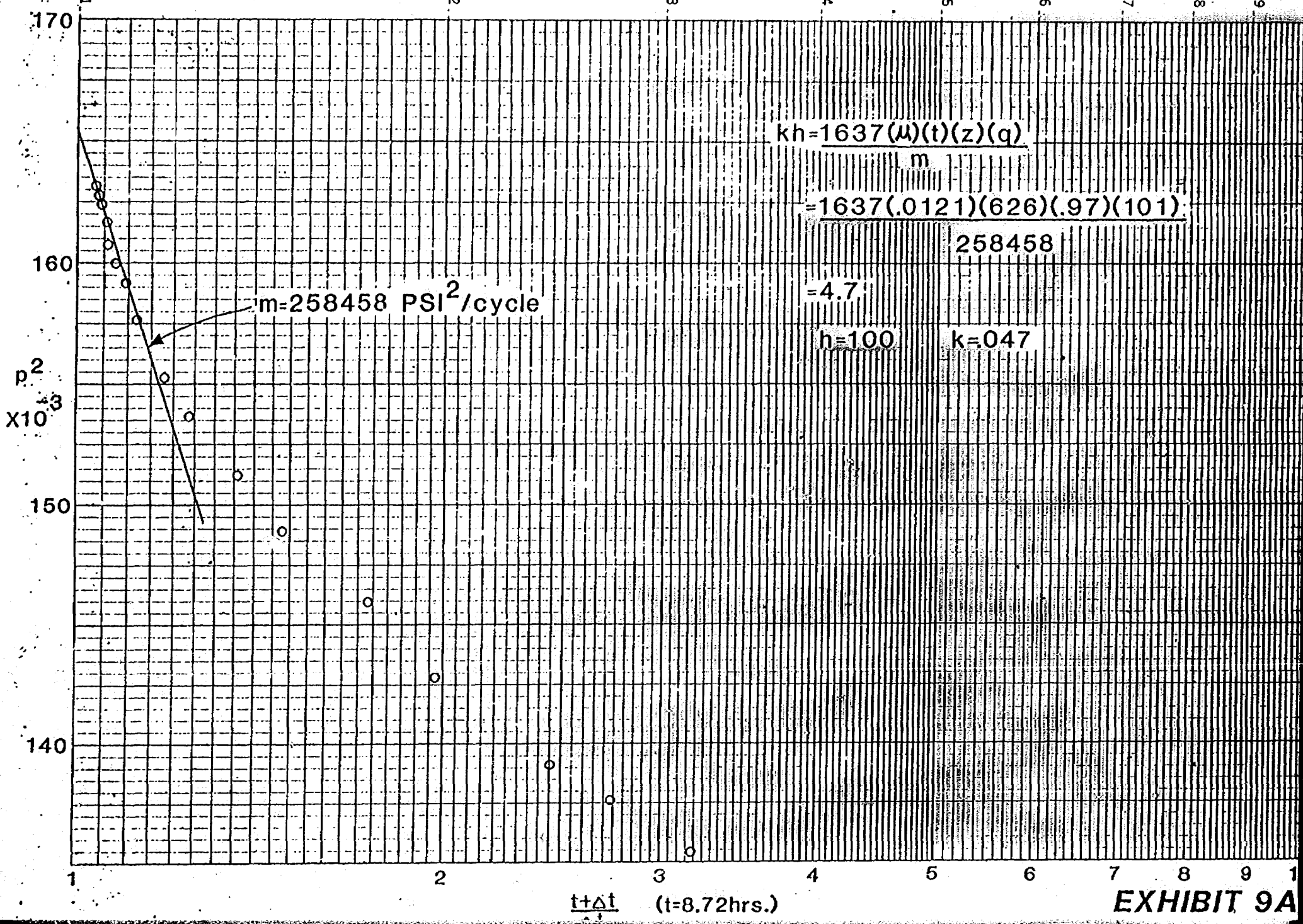
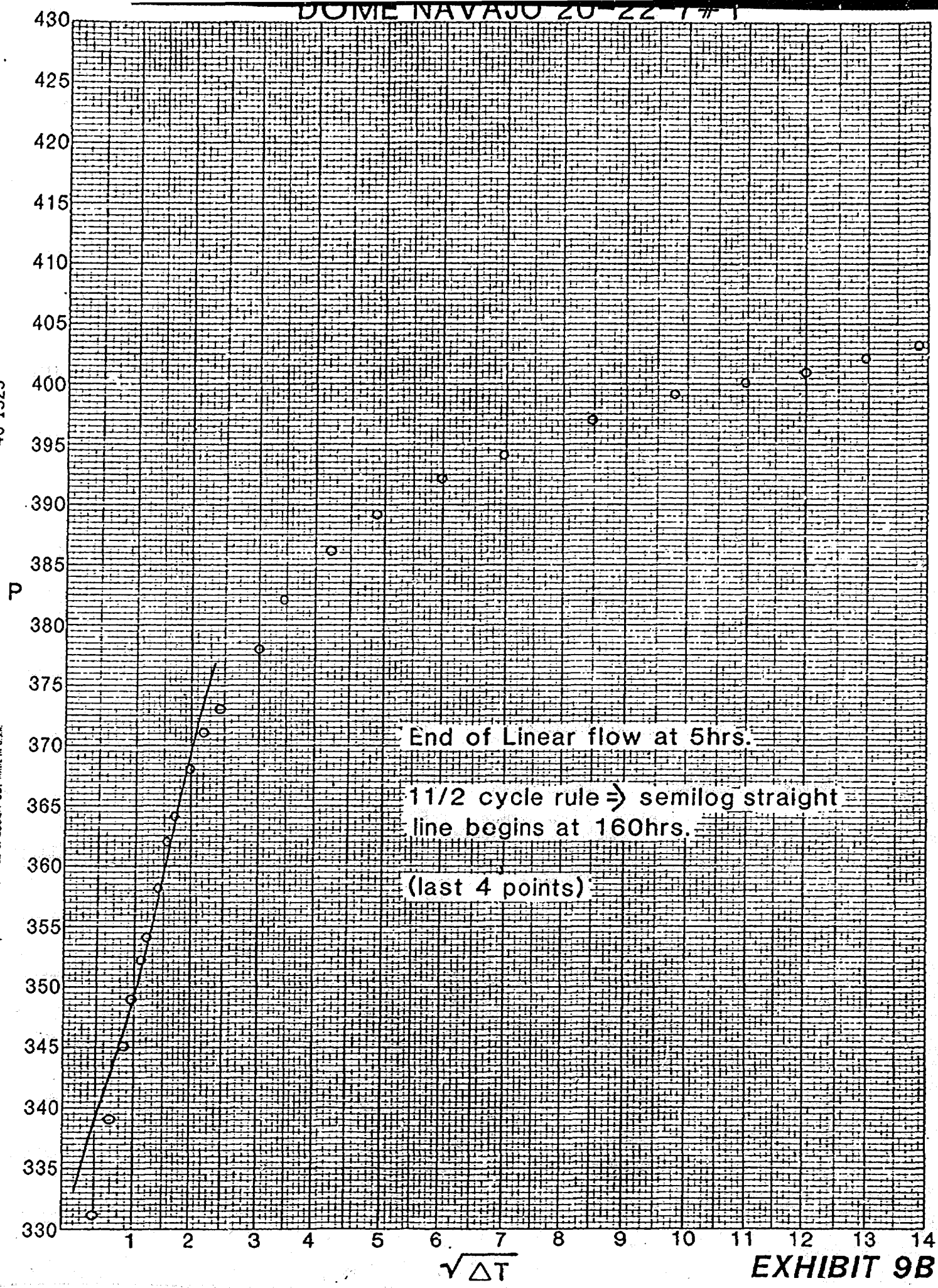


EXHIBIT 9A

DOME NAVAJO 20-22-1#1



46 1323

KE 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

EXHIBIT 9B

RECEIVED
JUN 25 1979
DOME DENVER

Petroleum Reservoir Engineering
DALLAS, TEXAS

File 9106 GA-735

Company DOME PETROLEUM CORPORATION Formation UPPER CHACRA

Well DOME FEDERAL 30-22-6 NO. 1 County

Field State

Chromatographic Gas Analysis

COMPONENT	MOL PER CENT	G. P. M.	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Carbon Dioxide	.05				
Nitrogen	2.00				
Methane	88.07				
Ethane	6.11	1.534			
Propane	2.46	.673			
iso-Butane	.39	.127			
n-Butane	.48	.150			
iso-Pentane	.17	.062			
n-Pentane	.10	.036			
Hexanes	.08	.032			
Heptanes plus	.09	.041			
	100.00	2.655			

Calculated gas gravity (air=1.000) = .638

Calculated gross heating value = 1104 BTU per cubic foot of dry gas at 14.65 psia.

Collected at 100 psig and 110° F.

SAMPLE DETAILS

Type Gas

Client Sample No. Cylinder No.

Date Sampled Temperature °F

Sampling Pressure psig Sampled By

These analyses, opinions or interpretations are based on observations and material supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations as to the productivity, proper operation, or profitableness of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

17, Third Chacra Net Sec. 7/17

EL PASO NATURAL GAS COMPANY
SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. WE23734

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Navajo Federal 1-X Secured By Don Norton

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	1.57		
Methane	88.92		
Ethane	5.32		
Propane	2.43	.6679	
I-Butane	.39	.1272	
N-Butane	.47	.1477	
I-Pentane	.16	.0584	
N-Pentane	.09	.0325	
Hexane	.10	.0435	
TOTALS	100.00	1.076	

Run By Hazen Checked By James

Remarks
R L Ahrens
H.L. Holder
R. Ullrich
R.E.Johnson
R.B. Herr
M.E. Blakely
R. F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 355 @ 57° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1105
Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00
Mercaptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .633
Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used
Calculation By
Carbon Dioxide
Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 23 T. 22 N. R. 7 W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

EL PASO NATURAL GAS CO.
SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF28732

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Rusty Navajo #2 Secured By Jess Goodwin

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	1.43		
Methane	88.94		
Ethane	5.83		
Propane	2.47	.6739	
I-Butane	.40	.1304	
N-Butane	.43	.1509	
I-Pentane	.17	.0620	
N-Pentane	.11	.0397	
Hexane	.07	.0304	
TOTALS	100.00	1.092	

Run By Hazen Checked By James

Remarks
R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.E. Herr
M.L. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File.

Source 3180 @ 55° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1108

Colorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercaptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .633

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 23 T. 22 N. 7 R. W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

EL PASO NATURAL GAS COMPANY
SAN JUAN LABORATORY

ONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 7-11-75 Analysis No. VF 27475

Sample From Chace Oil Company Date Secured 7-9-75

Sample Marked #1 Gulf Federal Secured By C. C. Kennedy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
arbon Dioxide	0.07		
ydrogen Sulfide	Not Run		
itrogen	4.58		
ethane	88.28		
thane	4.50		
ropane	1.66	0.456	
-Butane	0.39	0.127	
-Butane	0.28	0.088	
-Pentane	0.13	0.047	
-Pentane	0.06	0.022	
lexane	0.05	0.022	
TOTALS	100.00	0.762	

By Ross Checked By James

cc: R L Ahrens
H. L. Holder
R. Ullrich
R. E. Johnson Zone Perf: 1969' to 73',
R. B. Herr 1982' to 84' and 2039 to
M. E. Blakely, Jr. 41'
R. F. Lemon
J. E. Ashworth
Don Adams
File

C. C. Kennedy
4949 San Pedro, N.E.
Albuquerque, New Mexico 87109

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition

Calorimeter 1045

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide

Mercaptans

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition 0.626

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used: AE & MS
Calculation By: NGPA
Carbon Dioxide: NGPA
Hydrogen Sulfide: Cd Cl2

LOCATION AND WELL DATA
Sec. T. N. R. W.
County
State
Formation
Bomb Pressure

SAN JUAN LABORATORY

ACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF23733

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Gulf Federal #3 Secured By Rodger Hardy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	4.02		
Methane	33.32		
Ethane	4.28		
Propane	1.83	.5023	
i-Butane	.43	.1402	
N-Butane	.32	.1006	
i-Pentane	.13	.0474	
N-Pentane	.07	.0252	
Hexane	.05	.0217	
TOTALS	100.00	.838	

n By Hazen Checked By James

emarks

R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.B. Kerr
M.E. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 315 @ 56° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1054

Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercoptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .626

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 13 T. 22 N. R. 7 W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

EL PASO NATURAL GAS COMPANY
SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 10-16-75 Analysis No. VF 27943

Sample From Chace Oil Company Date Secured 10-13-75 @ 1615 hours

Sample Marked Rusty Federal #3 Secured By McAnally

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	0.08		
Hydrogen Sulfide			
Nitrogen	1.56		
Methane	88.48		
Ethane	6.22		
Propane	2.21	0.607	
I-Butane	0.36	0.117	
N-Butane	0.42	0.132	
I-Pentane	0.16	0.058	
N-Pentane	0.10	0.036	
Hexane	0.41	0.178	
TOTALS	100.00	1.128	

Run By Ross Checked By James

Remarks

R L Ahrens
H. L. Holder
R. Ullrich
R. E. Johnson
H. McAnally - 3
File
R. B. Herr
M. E. Blakely, Jr.
R. F. Lemon
Don Adams
File

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1116

Calorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide

Mercaptans

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition 0.640

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used	AE & MS
Calculation By	NGPA
Carbon Dioxide	NGPA
Hydrogen Sulfide	Cd Cl₂

LOCATION AND WELL DATA

Sec. 14 T. 22 N. R. 7 W.
County: Sandoval
State: New Mexico
Formation: La Ventana - Rusty Pond
Bomb Pressure: 97# @ 60°F

in general P.D.C + Liq.
envelope from mailroom
(2 PC) yc.

8 DRY MODE METER RUSTY-FED#3-NEW-WELL 1976

N. Fields

COMPONENT	MOL%	GPM	SP GR	BTU
N2	1.22	0.000	0.012	0.
CH4	89.53	0.000	0.496	906.
C2	5.76	0.000	0.060	102.
CO2	0.11	0.000	0.002	0.
C3	2.26	0.623	0.034	57.
IC4	0.35	0.116	0.007	12.
NC4	0.41	0.130	0.008	13.
IC5	0.14	0.051	0.003	6.
NC5	0.07	0.026	0.002	3.
C6+	0.15	0.065	0.005	8.
	100.00	1.009	0.630	1109.
BASE MOLZ	99.68			

Northwest Pipeline Corporation
MAR 22 1976
Production Department

SAN JUAN LABORATORY

FRACTIONAL DISTILLATION ANALYSIS ☐ GAS CHROMATOGRAPHY ANALYSIS ☐

Date of Run 4-7-76 Analysis No. VF23733

Sample From Chace Oil Co. Date Secured 4-6-76

Sample Marked Gulf Federal #3 Secured By Rodger Hardy

COMPONENT	MOL. %	G.P.M.	LIQ. VOL. %
Carbon Dioxide	.05		
Hydrogen Sulfide	.00		
Nitrogen	4.02		
Methane	88.32		
Ethane	4.28		
Propane	1.33	.5023	
I-Butane	.43	.1402	
N-Butane	.32	.1006	
I-Pentane	.13	.0474	
N-Pentane	.07	.0252	
Hexane	.05	.0217	
TOTALS	100.00	.838	

n By Hazen Checked By James

emarks

R L Ahrens
H.L. Holder
R. Ullrich
R.E. Johnson
R.B. Kerr
M.E. Blakely
R.F. Lemon
J.E. Ashworth
D. Adams
L.E. Mabe
File

Source 315 @ 56° F

HEATING VALUE
B.T.U. PER CU. FT.

Dry Basis, 14.696 lbs./sq. in., 60° F.
Calculated from % Composition 1054

Colorimeter

SULPHUR CONTENT
GRAINS PER 100 CU. FT.

14.7 lbs./sq. in., 60° F.
Hydrogen Sulfide .00

Mercoptans .00

SPECIFIC GRAVITY

14.696 lbs./sq. in., 60° F.
Calculated from % Composition .626

Calculated from % Liquid

VAPOR PRESSURE

PSIA at 100° F.
Calculated from Mole %

Column/s Used

Calculation By

Carbon Dioxide

Hydrogen Sulfide

LOCATION AND WELL DATA

Sec. 13 T. 22 N. R. 7 W.
County Sandoval
State N.M.
Formation La Ventana
Bomb Pressure 100 #

ADDITIONAL DETAIL FOR PRESSURE BUILDUP ANALYSIS
Dome Federal 19-22-6 #1

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 3c
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

Attached is a copy of the field data for an extended pressure buildup test for this well. Flow rates, bottom hole pressure, bottom hole temperature, and times were taken from this form.

Flowing time for the purpose of calculating superposition time in the Horner plot was calculated as follows:

cumulative production during the test divided by final flow rate times 24 = t (in hrs.) = 10.26 hrs.

A gas analysis was not available for this well so the average value for gas gravity from eight gas samples from other Chacra wells was used. Those gas analysis are attached. This average gas gravity of .63 was used in conjunction with Fig. D. 3 page 233 of Advances in Well Test Analysis by Robert C. Earlougher Jr. to get pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psia respectively. The average pressure was determined to be 371 psi by averaging the flowing pressure and the final shut in pressure.

$$\frac{306 + 437}{2} = 371 \text{ psi}$$

Reservoir temperature was taken from the field data and converted to degrees R

166 degrees F + 460 = 626 degrees R

Using this temperature and average pressure the pseudo reduced temperature and pseudo reduced pressure were calculated and

used with Fig. D.7 page 227 of Advances in Well Test Analysis by Robert C. Earlougher Jr.

$$Ppr = \frac{371}{670} = .55$$

$$Tpr = \frac{626}{367} = 1.7$$

$$z = .97$$

Next gas viscosity was estimated at the average pressure by using Fig. D.27 page 234 of Advances in Well Test Analysis to get μ = .0121 cp.

Other variables used in the calculation of k, the insitu permeability to gas, are as follows:

q = gas rate in MCF/Day = 275 the last recorded rate before shutting the well in.

Δt = shut in time, in hrs., from the field data

h = thickness of pay contributing to production = 105 feet. This number was determined by adding up the permeable zones with porosity greater than 8% as determined by a porosity log.

DOME/FED. 19-22-6#1

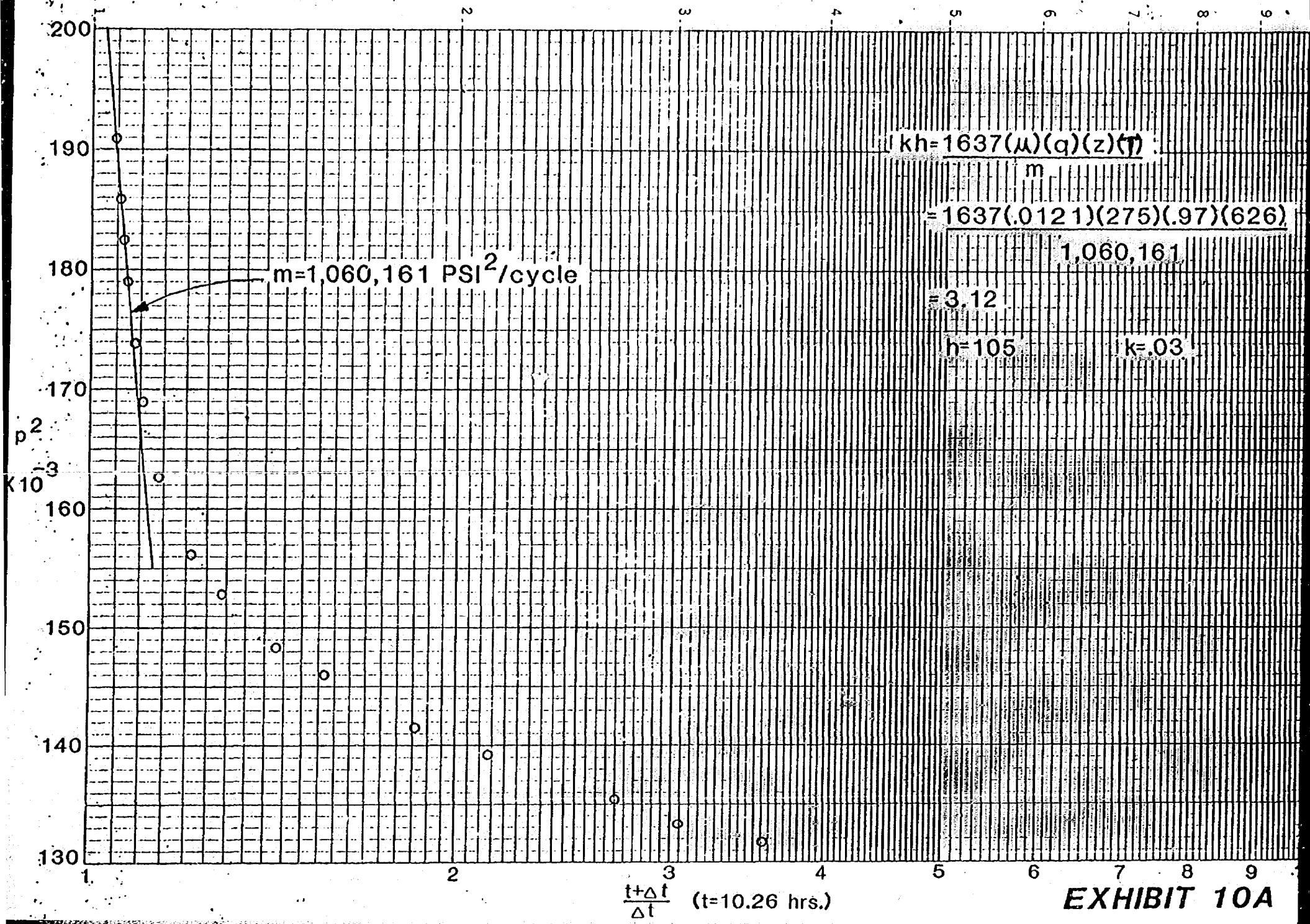


EXHIBIT 10A

DOME FED. 19 22 6W 1

46 1323

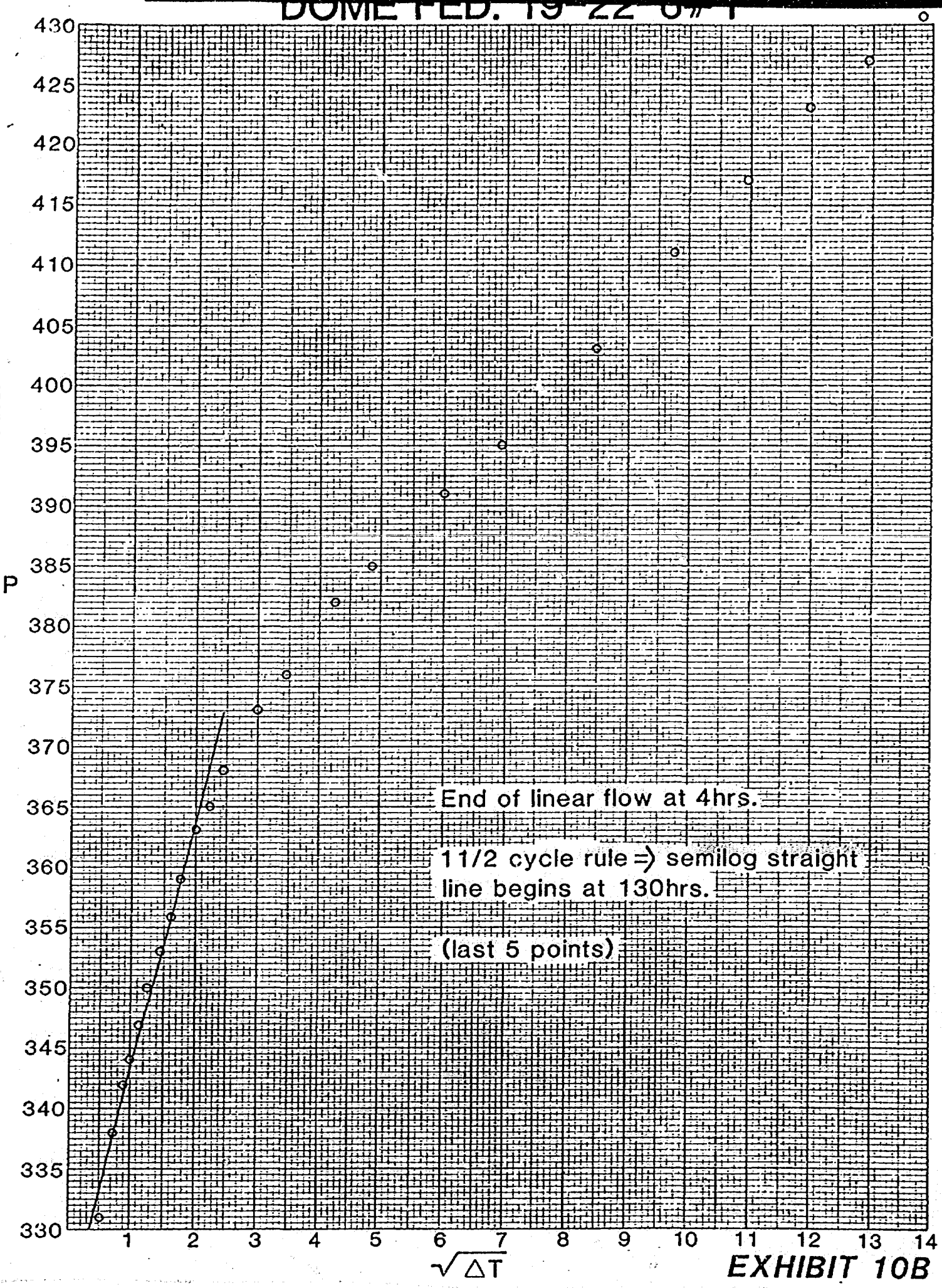


EXHIBIT 10B

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: FEDERAL NO. 19-22-6 No. 1 Page 1 of 8

Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1900' Psig
1-23	Arrived on location,							
"	shut-in	10:00						
"	Tandem instruments @ 1900'	11:08						403
"	"	11:30						403
"	Open on 1/4" orifice plate,							
"	producing thru casing	11:30	0	00				
"	"	12:00	0	30				356
"	"	12:30	1	00	416	Vac.	296	347
"	"	13:00	1	30				342
"	"	13:30	2	00	392	Vac.	278	336
"	"	14:00	2	30				332
"	"	14:30	3	00	375	Vac.	266	328
"	"	15:00	3	30				326
"	"	15:30	4	00	360	Vac.	255	323
"	"	16:00	4	30				321
"	"	16:30	5	00	348		246	319
"	"	17:00	5	30				316
"	"	17:30	6	00	334		236	314
"	"	18:00	6	30				311
"	"	18:30	7	00	321		226	308
"	"	19:00	7	30				307
"	"	19:30	8	00	275		192	306
"	Shut-in for build up	19:30	0	00				
"	"	19:45	0	15				331
"	"	20:00	0	30				338
"	"	20:15	0	45				342
"	"	20:30	1	00				344
"	"	20:45	1	15				347
"	"	21:00	1	30				350
"	"	21:30	2	00				353
"	"	22:00	2	30				356
"	"	22:30	3	00				359
"	"	23:30	4	00				363
1-24	"	00:30	5	00				365
"	"	01:30	6	00				368
"	"	04:30	9	00				373
"	"	07:30	12	00				376
"	"	13:30	18	00				382
"	"	19:30	24	00				385

TEFTELLER, INC.
RESERVOIR ENGINEERING DATA
Midland, Texas

Well: FEDERAL NO. 19-22-6 No. 1 Page 2 of 8

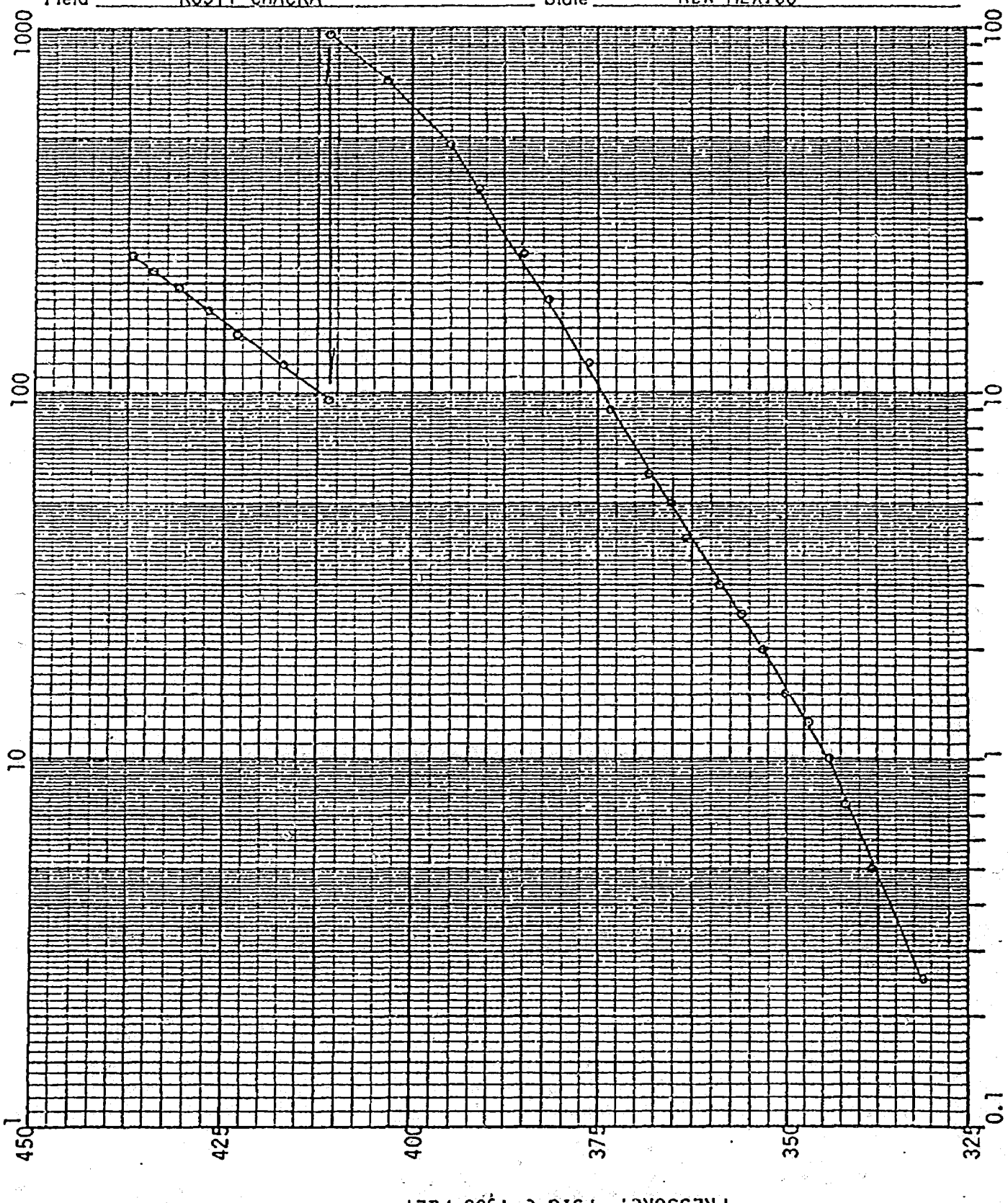
Field: RUSTY CHACRA File 2-11395-FT&BU

CHRONOLOGICAL PRESSURE AND PRODUCTION DATA

1981 Date	Status of Well	Time	Elapsed Time Hrs.	Min.	Daily Rate Gas MCF/D	Wellhead Pressure Tbg	Csg	BHP @ 1900' Psig
1-25	Continued shut-in	07:30	36	00				391
"	"	19:30	48	00				395
1-26	"	19:30	72	00				403
1-27	"	19:30	96	00				411
1-28	"	19:30	120	00				417
1-29	"	19:30	144	00				423
1-30	"	19:30	168	00				427
1-31	"	19:30	192	00				431
2-1	"	19:30	216	00				434
2-2	Pull instrument	15:00	235	30		Nil	378	437
"	Gradient Traverse	15:30	236	00				437

TEFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Formation CHACRA
Well FEDERAL 19-22-6 NO. 1 County SANDOVAL
Field RUSTY CHACRA State NEW MEXICO



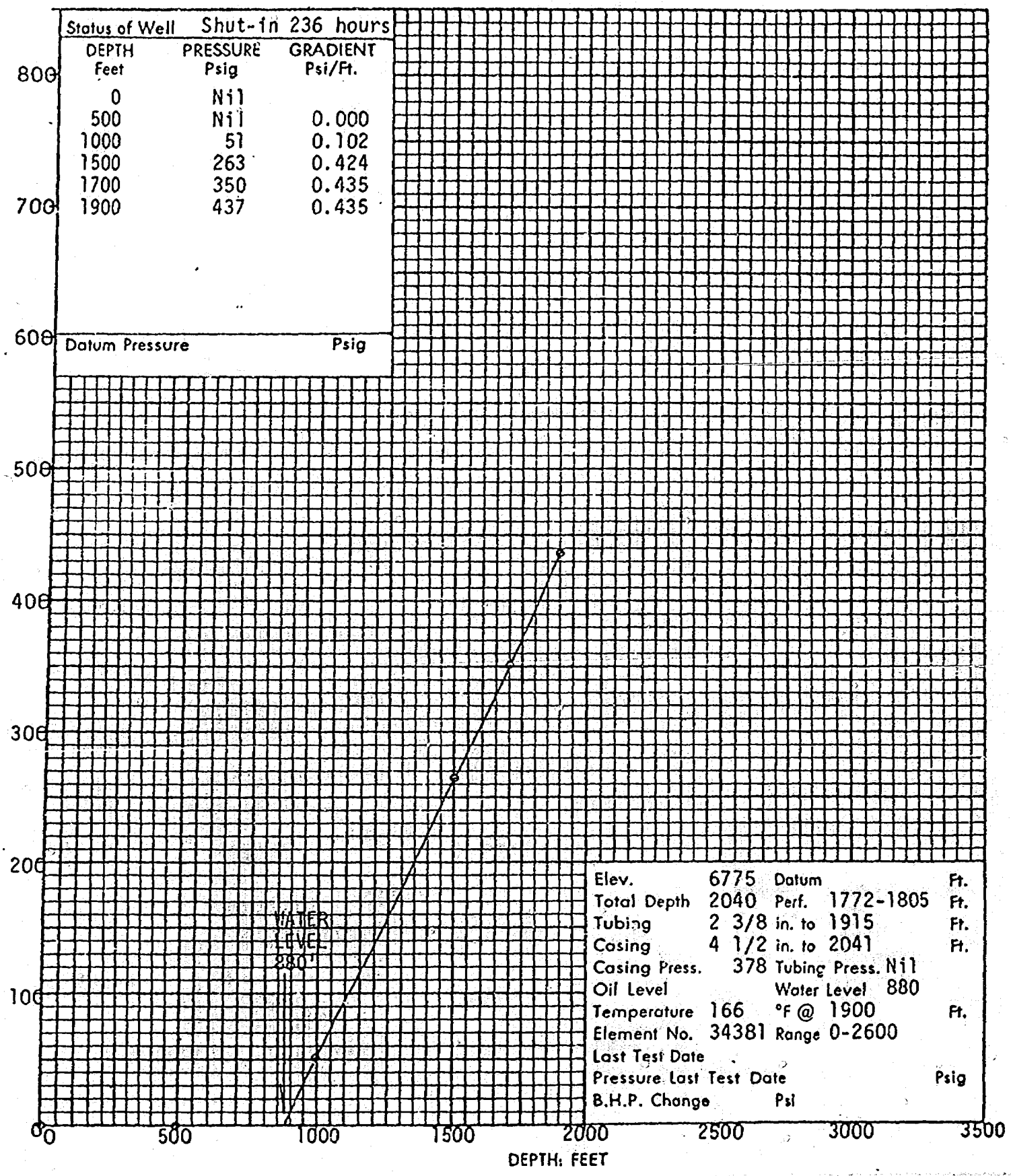
EFTELLER, INC.
reservoir engineering data
MIDLAND, TEXAS

Company DOME PETROLEUM CORPORATION Lease FEDERAL 19-22-6 Well No. 1
Field RUSTY CHACRA County SANDOVAL State NEW MEXICO
Formation CHACRA Test Date FEBRUARY 2, 1981

Status of Well Shut-in 236 hours

DEPTH Feet	PRESSURE Psig	GRADIENT Psi/Ft.
0	Nil	
500	Nil	0.000
1000	51	0.102
1500	263	0.424
1700	350	0.435
1900	437	0.435

Datum Pressure Psig



Elev.	6775	Datum	Ft.
Total Depth	2040	Perf. 1772-1805	Ft.
Tubing	2 3/8	in. to 1915	Ft.
Casing	4 1/2	in. to 2041	Ft.
Casing Press.	378	Tubing Press. Nil	
Oil Level		Water Level 880	
Temperature	166	°F @ 1900	Ft.
Element No.	34381	Range 0-2600	
Last Test Date			
Pressure Last Test Date			Psig
B.H.P. Change		Psi	

Dome
Fed.
19-22-6
#1

Perf. 1698-1700
2 holes

Perf 1708
1 hole

Perf.
1714-22
5 holes

Perf.
1724-
36 7 holes

Perf
1738-44
4 holes

Perf.
1772-79
8 holes

Perf.
1794-96
3 holes

Perf.
1804-05
2 holes

2'

6'

44'

30'

8'

6'

105'

FOAM FRAC 32,000 gal

STAGE 2

FOAM FRAC

RECEIVED
JUN 04 1981
OIL CONSERVATION DIVISION
SANTA FE

BEFORE THE OIL CONSERVATION DIVISION

ENERGY AND MINERALS DEPARTMENT

OF THE STATE OF NEW MEXICO

IN THE MATTER OF THE APPLICATION :
OF DOME PETROLEUM CORPORATION FOR :
DESIGNATION OF A TIGHT FORMATION :
SANDOVAL COUNTY, NEW MEXICO :

Case No. 7300

APPLICATION

COMES NOW, DOME PETROLEUM, by its undersigned attorneys and for its application herein, respectfully states:

1. The applicant is the owner of an interest in the Chacra Formation underlying the following described lands situated in Sandoval County, New Mexico:

Township 21 North, Range 5 West
Sections 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

Township 21 North, Range 6 West
Sections 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 20, 21, 22, 23, 24, 25, 26, 27, 35, 36

Township 21 North, Range 7 West
Sections 1, 2, 3, 4, 10, 11, 12, 13

Township 22 North, Range 6 West
Sections 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

Township 22 North, Range 7 West
Sections 1 through 36 inclusive

Containing 73,017.58 acres, more or less.

2. The Chacra Formation underlying the above described lands is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy.

3. The stabilized production rate, against atmospheric pressure, of wells completed for production in the Chacra Formation within the area described, without stimulation, is not expected to exceed the production maximum levels set forth in 18 C.F.R. Section 271.703 (c)(2)(B).

4. No well drilled into the Chacra Formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

WHEREFORE, the applicant prays as follows:

A. That this application be set for hearing before an examiner, with notice of said hearing given as required by law.

B. That upon such hearing, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 C.F.R. Section 271.701-705, the Chacra Formation underlying the lands described herein be designated as a tight formation.

C. For such further relief as the Division deems just and proper.

DATED this 4th day of June, 1981.

DOME PETROLEUM CORPORATION

By: White, Koch, Kelly & McCarthy
A Professional Association

By: Kenneth Bateman
Kenneth Bateman
Attorneys for the Applicant
P.O. Box 787
Santa Fe, New Mexico 87501

BEFORE THE OIL CONSERVATION DIVISION

ENERGY AND MINERALS DEPARTMENT

OF THE STATE OF NEW MEXICO

RECEIVED
JUN 04 1981
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION :
OF DOME PETROLEUM CORPORATION FOR :
DESIGNATION OF A TIGHT FORMATION :
SANDOVAL COUNTY, NEW MEXICO :

Case No. 7300

APPLICATION

COMES NOW, DOME PETROLEUM, by its undersigned attorneys and for its application herein, respectfully states:

1. The applicant is the owner of an interest in the Chacra Formation underlying the following described lands situated in Sandoval County, New Mexico:

Township 21 North, Range 5 West
Sections 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

Township 21 North, Range 6 West
Sections 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 20, 21, 22, 23, 24, 25, 26, 27, 35, 36

Township 21 North, Range 7 West
Sections 1, 2, 3, 4, 10, 11, 12, 13

Township 22 North, Range 6 West
Sections 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

Township 22 North, Range 7 West
Sections 1 through 36 inclusive

Containing 73,017.58 acres, more or less.

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By: Kenneth Bateman
Kenneth Bateman
Attorneys for the Applicant
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Santa Fe, New Mexico 87501

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Township 21 North, Range 7 West
Sections 1, 2, 3, 4, 10, 11, 12, 13

Township 22 North, Range 6 West
Sections 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

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Sections 1 through 36 inclusive

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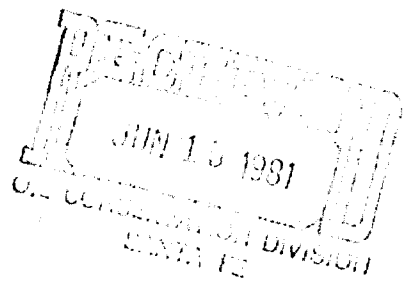
DATED this 4th day of June, 1981.

DOME PETROLEUM CORPORATION

By: White, Koch, Kelly & McCarthy
A Professional Association

By: Kenneth Bateman
Kenneth Bateman
Attorneys for the Applicant
P.O. Box 787
Santa Fe, New Mexico 87501

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION



June 9, 1981

Case 7300

Oil Conservation Division
Energy and Minerals Department
State of New Mexico
State Capitol
P. O. Box 2088
Santa Fe, NM 87503

Attention: Miss Florine Davidson

Re: In the Matter of the Application of
Dome Petroleum Corporation for
Designation of a Tight Formation,
Sandoval County, New Mexico

Dear Florine:

In connection with the application of Dome Petroleum Corporation which I understand will be set for hearing on July 2, 1981, enclosed is one complete copy of the proposed exhibits.

I understand that you are requesting three copies of the exhibits. Two additional copies will be forwarded to you shortly.

Thank you for all your assistance to me in this matter.

Sincerely,

Kenneth Bateman

KB/lja
enclosures

cc: K. F. Tracy

Mailing Address: P.O. Box 787, Santa Fe, N.M. 87501
Street Address: 220 Otero St., Santa Fe, N.M. 87501 (505) 982-4374

L. C. White
Sumner S. Koch
William Booker Kelly
John F. McCarthy, Jr.
Kenneth Bateman
Benjamin Phillips
C. Emery Cuddy, Jr.
Larry C. White
Forrest S. Smith
Daniel H. Friedman
John N. Patterson
Paula Tackett
Filmore E. Rose

Attorneys and Counselors at Law

EXHIBITS FOR PROPOSED

TIGHT GAS FORMATION AREA

CHACRA FORMATION

RUSTY CHACRA AREA

SANDOVAL COUNTY, NEW MEXICO

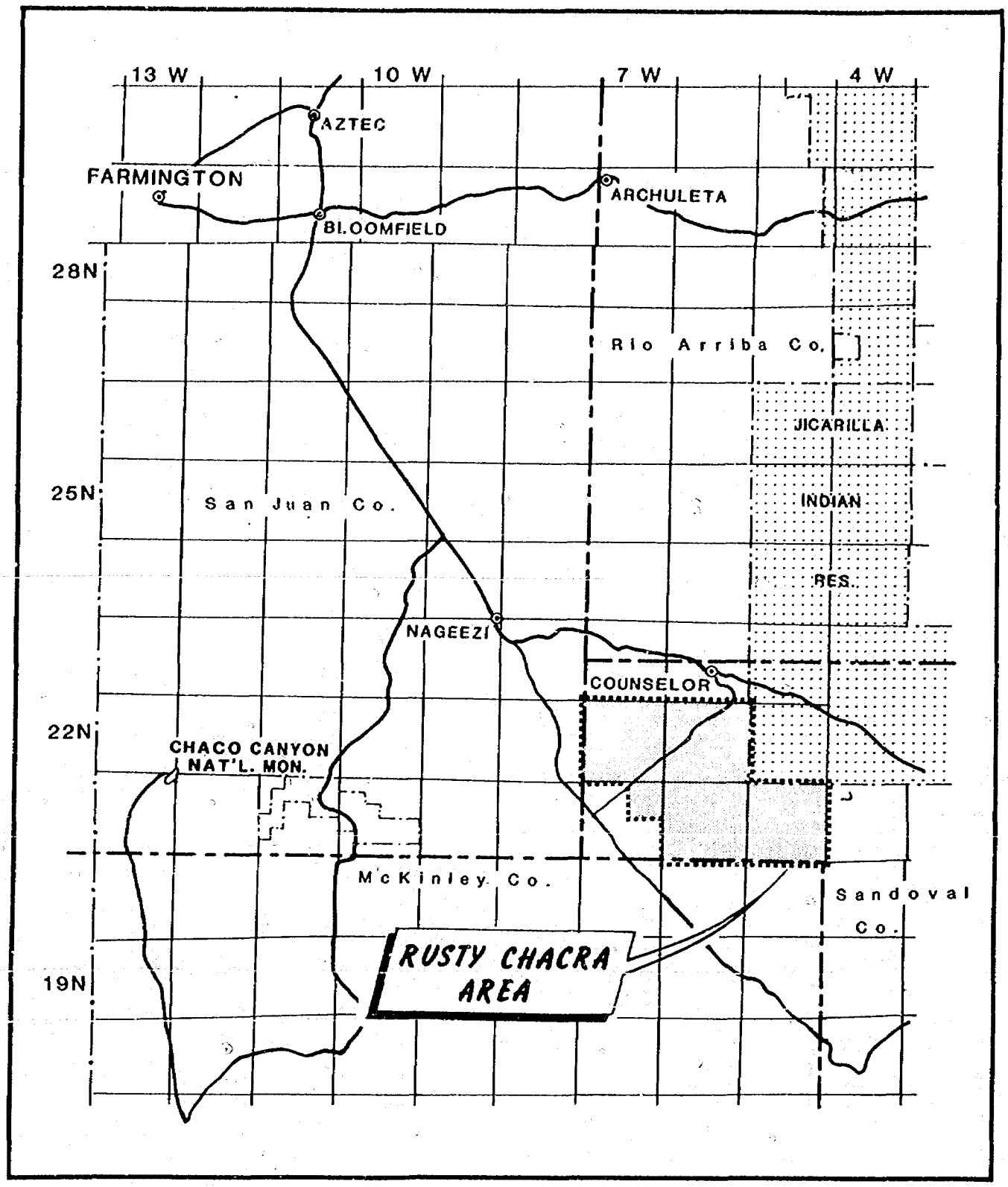
May, 1981

Dome Petroleum Corp.
2900 Dome Tower
1625 Broadway
Denver, Colorado 80202

SUMMARY OF EXHIBITS

RUSTY CHACRA AREA

Exhibit No.	Title or Subject
1	Index map showing relative location of application area
2	Structure Map
3	Summary of Geology
4	Cross Section
5	Type Log
6	Summary of Reservoir data
7	Summary of Pertinent Data by well
8	Pressure Build-up analysis Chase Rusty Federal #4 Horner plot and P vs $\sqrt{\Delta t}$ plot
9	Pressure Build-up analysis Dome Navajo 20-22-7 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
10	Pressure Build-up analysis Dome Federal 19-22-6 #1 Horner plot and P vs $\sqrt{\Delta t}$ plot
11	Summary of wells with measured unstimulated rates
12	Typical casing design



INDEX MAP OF NORTH WESTERN NEW MEXICO
SHOWING RELATIVE LOCATION OF
RUSTY CHACRA AREA

Exhibit 1

Rusty Chacra Area Tight Gas Hearing

Exhibit #3

Summary of Geology

The Rusty Chacra Area is located six miles south of the town of Counselor in Sandoval Co., New Mexico. Geologically, the area is located on the Chaco Slope of the southern San Juan Basin. Gas production is from a buildup of transitional shaly sands and siltstones which are interpreted to be of a prodelta low-energy origin. This productive zone which is called the "Chacra" is the time-stratigraphic equivalent of the upper Unnamed Tongue of the Cliffhouse beach sandstone. Structural dip to the north-east of about 100 feet per mile is of little consequence as this is a stratigraphic trap. The sandstones are gray to light gray, fine grained, silty, shaly, and slightly to moderately calcitic.

The fine grained and clay filled nature of the sands results in low porosity and permeability and commercial production when obtained is only achieved through extensive fracturing and reservoir treatment.

EXHIBIT 8, 9, and 10 - Pressure Build-up Analysis

These exhibits show how in-situ permeability to gas was calculated for each of three Chacra wells which had extended pressure build-ups. For each of the three wells a Horner plot of pressure squared vs. $(t + \Delta t)/\Delta t$ is shown as well as a plot of pressure vs. $\sqrt{\Delta t}$. The straight line portion of the Horner plot is used to calculate permeability. Early data is affected by wellbore storage and linear flow in fractures induced by hydraulic fracture stimulation treatment. The second plot of pressure vs. $\sqrt{\Delta t}$ helps to show which part of the Horner plot should be used in the calculation of permeability and which part is still affected by linear flow and storage. The results of these three extended pressure surveys are as follows:

WELL	IN-SITU PERMEABILITY
Chase Rusty Federal #4	0.13 md
Dome Navajo 20-22-7 #1	0.05 md
Dome Federal 19-22-6 #1	0.04 md
Average	0.07 md

EXHIBIT 11 - Summary of Wells with Measured Unstimulated Rates

This table shows the Chacra completions in which unstimulated rates were reported after swabbing the well down prior to fracture treatment. The standard procedure in this area has been to stimulate the well immediately after perforating by hydraulic fracturing methods. Due to this procedure unsimulated rates were

generally not reported except for the wells shown in this table. This table shows that in all cases unstimulated rates were below the guidelines given in 18 CFR 271.705 which specifies for 1658' (the average depth to the top of the Chacra) a maximum unstimulated rate of 59 MCFD. The average for the wells shown in this exhibit is a rate too small to measure and represents the expected unstimulated rate for this formation. It should also be noted that none of these wells have produced any crude oil before or after stimulation.

EYHIBIT 12 -- Typical Casing Design

This exhibit shows how any potential fresh water zones would be protected by surface casing and production casing which are both cemented to surface.

KFT:jp

SUMMARY OF RESERVOIR DATA

RUSTY CHACRA AREA

Exhibit 6

Reservoir Temperature	160 degrees F
Average Reservoir Pressure	460 psia
Average Depth to Top of Chacra	1658'
Average Porosity	11%
Average Permeability	0.07 md
Average Unstimulated Flow Rate	TSTM
Average 3 hr. Potential Test Rate	594 MCFD
Crude Oil Production	None

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Cole	Alamos Canyon #1	SW	4	21N	6W	1/11/81*	1370	1396-1436	275	SIGW
Cole	Alamos Canyon #6	SE	6	21N	6W	8/18/80*	1304	1304-1343	1025	SIGW
Cole	Alamos Canyon #9	NW	6	21N	6W	1/6/81*	1400	1426-1469	793	SIGW
Cole	Alamos Canyon #3	NE	7	21N	6W	3/5/80*	1260	1282-1312	435	SIGW
Cole	Alamos Canyon #7	NW	7	21N	6W	8/21/80*	1250	1252-1304	880	SIGW
Cole	Alamos Canyon #2	NE	8	21N	6W	2/27/80*	1330	1353-1393	160	SIGW
Cole	Alamos Canyon #5	SW	9	21N	6W	8/31/80*	1320	1326-1362	450	SIGW
Cole	Alamos Canyon #10	NW	15	21N	6W	1/9/81*	1360	1383-1422	475	SIGW
NW Expl.	Natani #1	SE	11	21N	6W	6/28/79	1563	1580-1662	559	SIGW
NW Expl.	Natani #2	NW	12	21N	6W	10/6/79*	1650	1682-1752	688	SIGW
Cole	Alamos Canyon #1	NW	15	21N	6W	3/1/80*	1350	1355-1403	380	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Kirby Exploration	Chorney State #1	SW	16	22N	6W	6/12/76	2270	2305-2346		PA
Benson	Federal #1	SW	17	22N	6W	9/15/78	1886	1903-1954	20	SIGW
Benson	Navajo #1	SW	18	22N	6W	4/30/78	1816	1820-1884	47	SIGW
Dome	Federal #2	SE	18	22N	6W	9/27/80*	1830	1865-1948	329	SIGW
Dome	Federal #3	NW	18	22N	6W	9/14/80*	1858	1874-1922	418	SIGW
Dome	Federal #1	SW	19	22N	6W	1/21/79	1681	1698-1805	359	SIGW
Benson	Federal #1	NE	19	22N	6W	7/8/78	1789	1816-1854	75	SIGW
Benson	Federal #1	SW	20	22N	6W	8/9/78	1780	1798-1848	576	SIGW
Dome	Federal #2	SE	20	22N	6W	8/30/80*	1947	1973-2013	1050	SIGW
Dome	Federal #3	NW	20	22N	6W	10/5/80*	1823	1853-1883	688	SIGW
Eng. Prod. Serv.	Tall Pine #1	SE	26	22N	6W	3/13/76	2030	2066-2158	54	SIGW
Kirby Exploration	Bradshaw Fed. #1	NE	27	22N	6W	6/16/76	2010	2023-2034		PA
Dome	Navajo #1	SW	27	22N	6W	12/11/80*	1737	1770-1790	684	SIGW
Benson	Federal #1	NW	28	22N	6W	7/24/78	1816	1834-2043	668	SIGW
Dome	Navajo #2	SE	28	22N	6W	9/6/80*	1762	1790-1860	918	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Dome	Navajo #4	SW	28	22N	6W	12/4/80*	1698	1734-1756	1429	SIGW
Dome	Federal #3	NE	29	22N	6W	11/24/80*	1804	1830-1860	1265	SIGW
Benson	Federal #1	SE	29	22N	6W	6/23/78	1702	1727-1800	977	SIGW
Dome	Federal #2	SW	29	22N	6W	8/26/80*	1790	1790-1880	960	SIGW
Benson	Dome Rusty #1	NE	30	22N	6W	5/25/78	1734	1758-1854	1509	SIGW
Dome	Federal #1	NW	30	22N	6W	1/31/79	1676	1675-1810	415	SIGW
Benson	Federal #1	SE	31	22N	6W	9/26/78	1536	1552-1600	262	SIGW
Benson	#1 State	NW	32	22N	6W	10/11/78	1637			SUSP
Dome	State #2	NE	32	22N	6W	12/1/80*	1620	1620-1706	1819	SIGW
Dome	Navajo #1	NW	34	22N	6W	12/7/80*	1773	1810-1894	1123	SIGW
Dome	Navajo #1	NW	35	22N	6W	12/15/80*	1912	1946-2034	136	SIGW
Benson	State #1	SW	36W	22N	6W	10/7/78	1766	1795-1831	68	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

RUSTY CHACRA

TIGHT FORMATION WELL DATA

OPERATOR	WELL NAME	LOCATION QTR., SEC., TWP., RNG.				SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Navajo #1	NW	9	22N	7W	8/3/78	1780			TA
Beard	#1 Chacra	NW	10	22N	7W	12/3/77	1780	1795-1902		SIGW
Dome	Federal #1	NE	10	22N	7W	9/10/80*	1852	1868-1910	733	SIGW
Benson	Navajo #1	SW	10	22N	7W	7/13/78	1690	1706-1804	866	SIGW
Chase	Gulf Fed. #2	NE	11	22N	7W	8/28/75	1934	1950-1988	700	PROD
Chase	Rusty Fed. #1	SE	11	22N	7W	7/31/74	1900	1901-1962	450	PROD
Chase	2 Gulf Navajo	SW	12	22N	7W	5/22/80*	1852	1967-1991	227	SIGW
Chase	Gulf Fed. #1	NW	13	22N	7W	2/28/75	1930	1969-2041	581	PROD
Chase	Gulf Fed. #3	NE	13	22N	7W	2/16/76	1930	1943-1980	348	PROD
Chase	Rusty Fed. #4	SW	13	22N	7W	10/8/75	1740	1758-1801	1423	PROD
Chase	Rusty Fed. #2	NE	14	22N	7W	2/21/75	1830	1880-1884	457	PROD
Chase	Rusty Fed. #3	SE	14	22N	7W	9/4/75	1750	1762-1804	1472	PROD
Dome	Federal #1	SE	15	22N	7W	1/16/79	1672	1708-1784	817	SIGW
Benson	Navajo #1	SE	17	22N	7W	7/17/78	1518	1719-1782		WOCU
Dome	Navajo #2	SW	17	22N	7W	9/19/80*	1471	1484-1572	133	SIGW
Dome	Navajo #1	NE	20	22N	7W	1/9/79	1470	1487-1520	158	SIGW

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OPERATOR	WELL NAME	LOCATION QTR.	SEC.	TWP.	RNG.	SPUD DATE	TOP CHACRA	COMPLETION INTERVAL	3 Hr. POTENTIAL AFTER FRAC MCFD	STATUS
Benson	Dome Rusty #1	SE	20	22N	7W	6/23/78	1426	1440-1600	482	SIGW
Benson	Navajo #1	NE	21	22N	7W	5/30/78	1516	1543-1640	470	SIGW
Beard	#2 Chacra	SE	21	22N	7W	12/12/77	1445	1456-1562	NR	SIGW
Chase	Rusty Navajo #5	NE	22	22N	7W	11/14/76	1660	1695-1917	960	PROD
Chase	Rusty Navajo #7	SW	22	22N	7W	4/16/77	1440	1564-1812	769	PROD
Chase	Rusty Navajo #2	NW	23	22N	7W	1/28/76	1665	1692-1776	802	PROD
Chase	Rusty Navajo 1-X	NE	23	22N	7W	1/31/76	1642	1667-1763	900	PROD
Chase	Rusty Navajo #3	SW	23	22N	7W	7/19/76	1524	1540-1743	298	PROD
Benson	Dome Rusty #1	SE	24	22N	7W	6/9/78	1636	1650-1699	569	SIGW
Benson	Federal #1	NE	25	22N	7W	10/24/78	1588			WOCU
Benson	Federal #1	NE	26	22N	7W	8/6/78	1510	1526-1730	544	SIGW
Chase	Rusty Navajc #4	NW	26	22N	7W	7/22/76	1510	1515-1731	404	PROD
Chase	Rusty Navajo #6	NE	27	22N	7W	5/3/77	1440	1465-1572	272	PROD
Merrion/Bayless	#2 Alemita	NW	28	22N	7W	2/27/78	1400	1507-1514	NR	SUSP
Dome	Navajo #2	SE	28	22N	7W	9/23/80*	1328	1342-1376	24	SIGW
Dome	Federal #1	NE	34	22N	7W	9/29/80*	1390	1405-1470	26	SIGW

* Meets spud date requirement for NGPA Section 107 incentive price.

K•Σ SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

CHASE/RUSTY/FED. #4

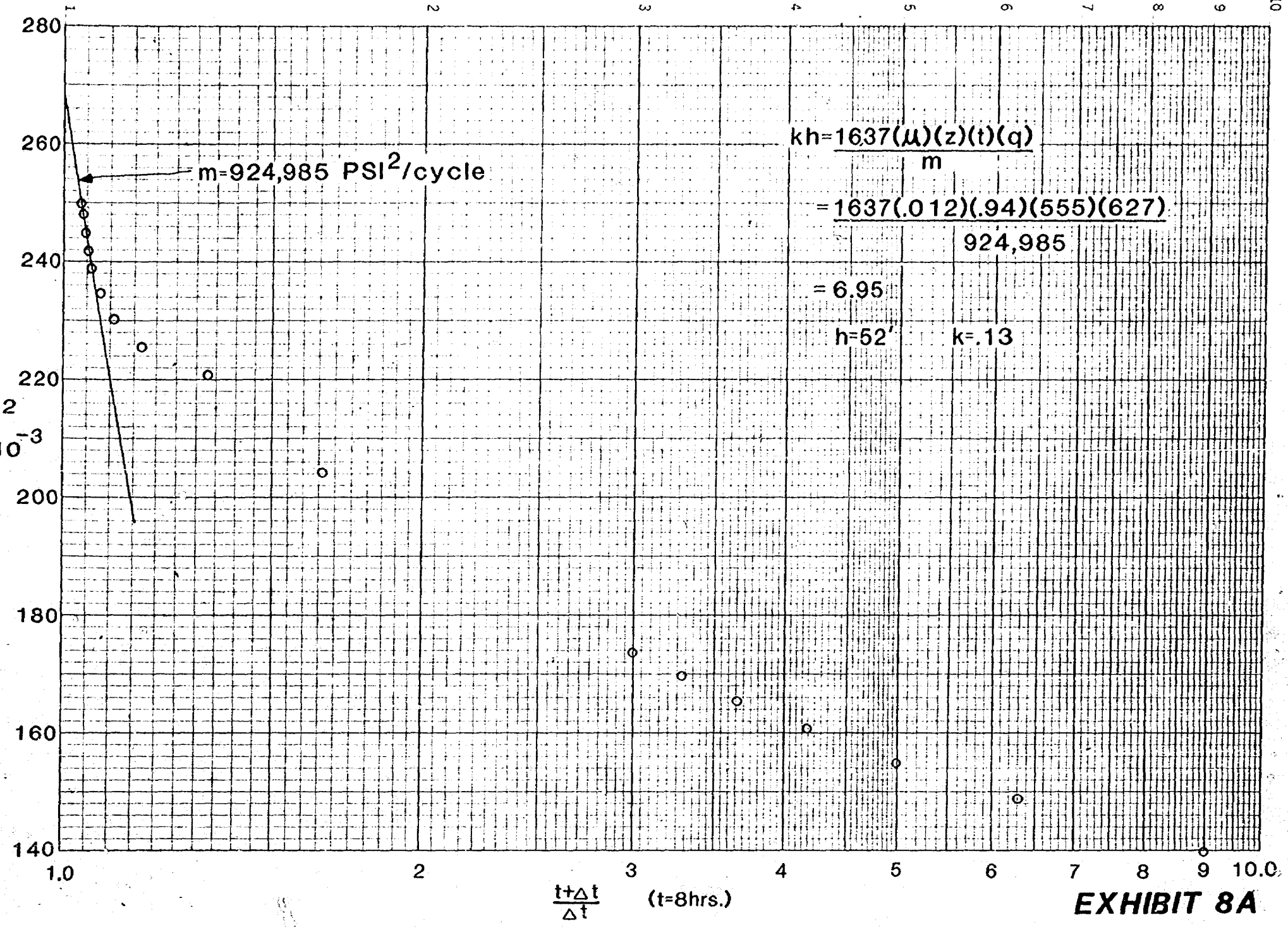


EXHIBIT 8A

K•E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

CHASE/RUSTY/FED. #4

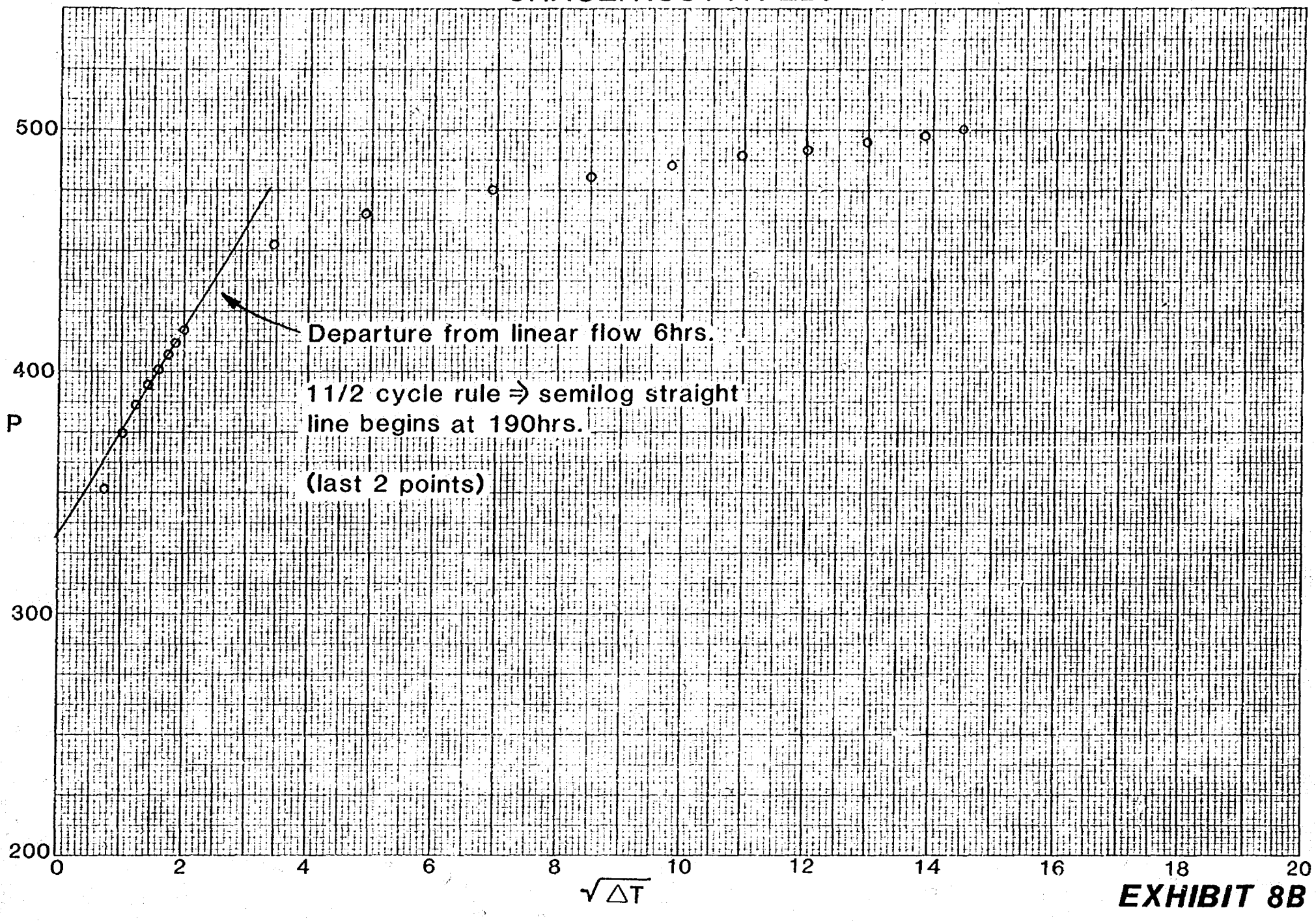


EXHIBIT 8B

K&E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME NAVAJO 20-22-7#1

$$kh = \frac{1637(\mu)(t)(z)(q)}{m}$$

$$= \frac{1637(.0121)(626)(.97)(101)}{258458}$$

$=4.7$

$h=100$ $k=.047$

$m=258458\ PSI^2/cycle$

p^2 $X10^{-3}$

170
160
150
140

1 2 3 4 5 6 7 8 9 10

$\frac{t+\Delta t}{\Delta t}$ $(t=8.72hrs.)$

EXHIBIT 9A

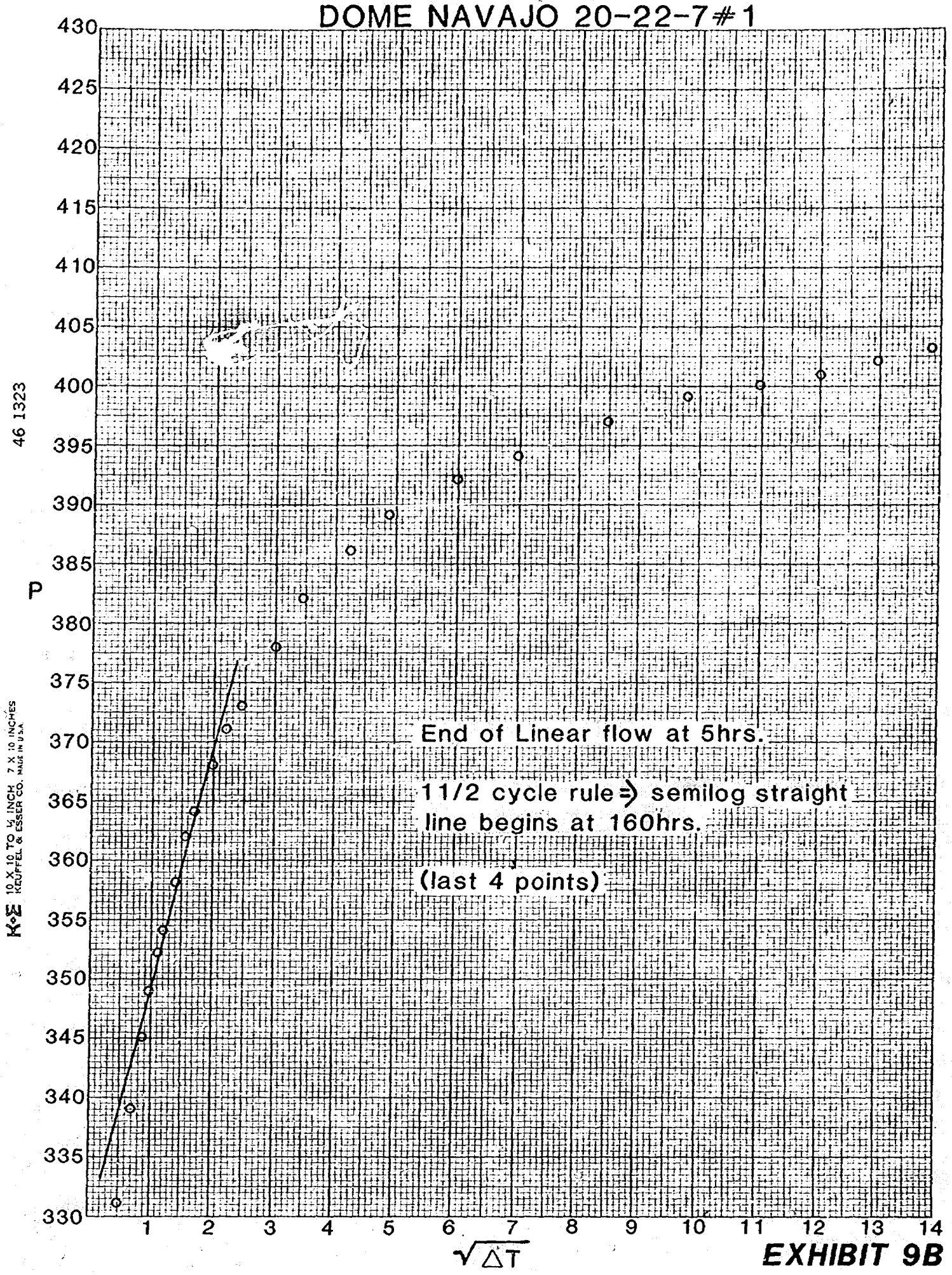

DOME NAVAJO 20-22-7#1
46 1323
P
End of Linear flow at 5hrs.
11/2 cycle rule ⇒ semilog straight line begins at 160hrs.
(last 4 points)
430
425
420
415
410
405
400
395
390
385
380
375
370
365
360
355
350
345
340
335
330
1
2
3
4
5
6
7
8
9
10
11
12
13
14
√ΔT
KEUFFEL & ESSER CO. MADE IN U.S.A.

EXHIBIT 9B

K+E SEMI-LOGARITHMIC 1 CYCLE X 70 DIVISIONS KEUFFEL & ESSER CO. MADE IN U.S.A.

46 4652

DOME/FED. 19-22-6#1

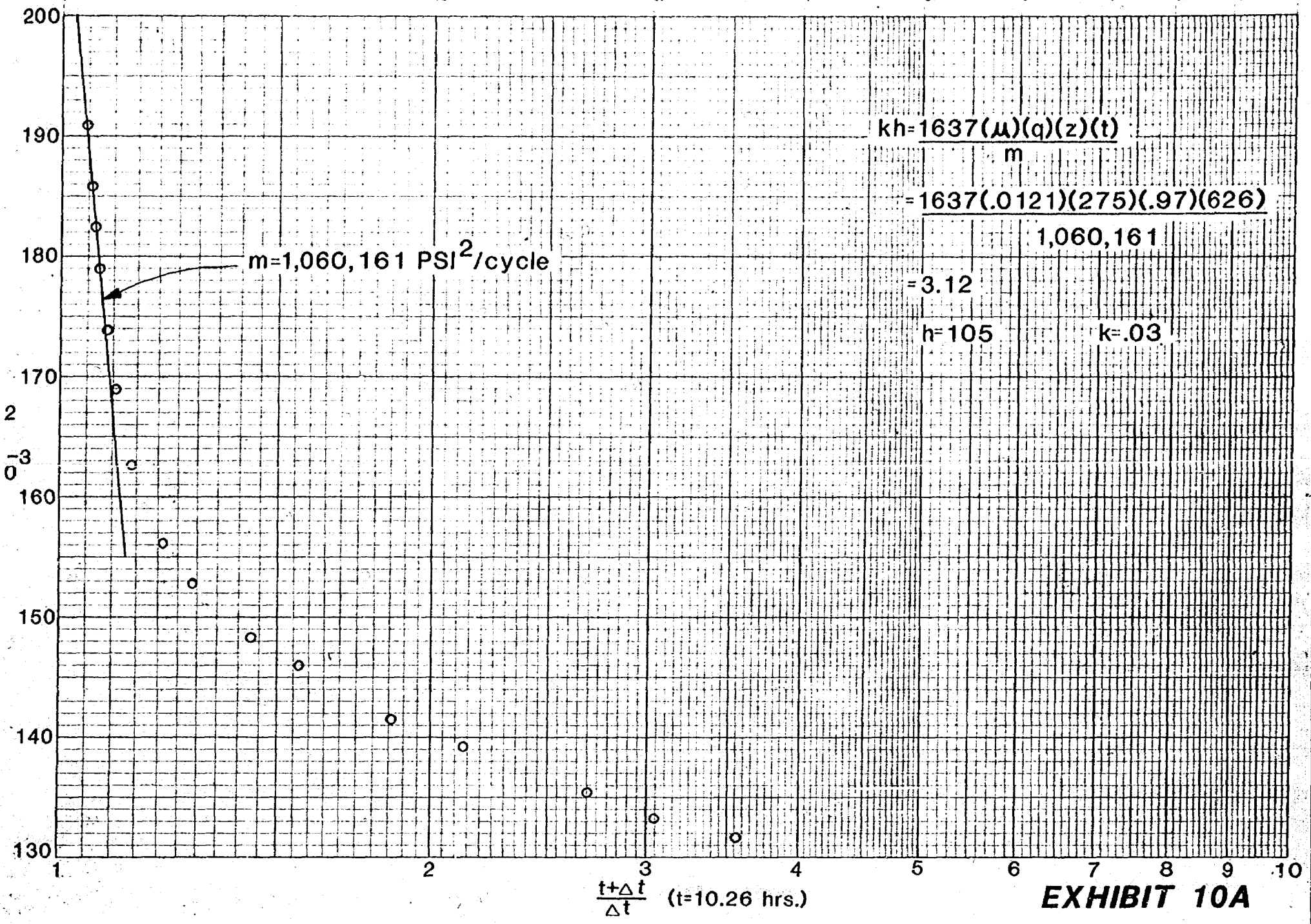
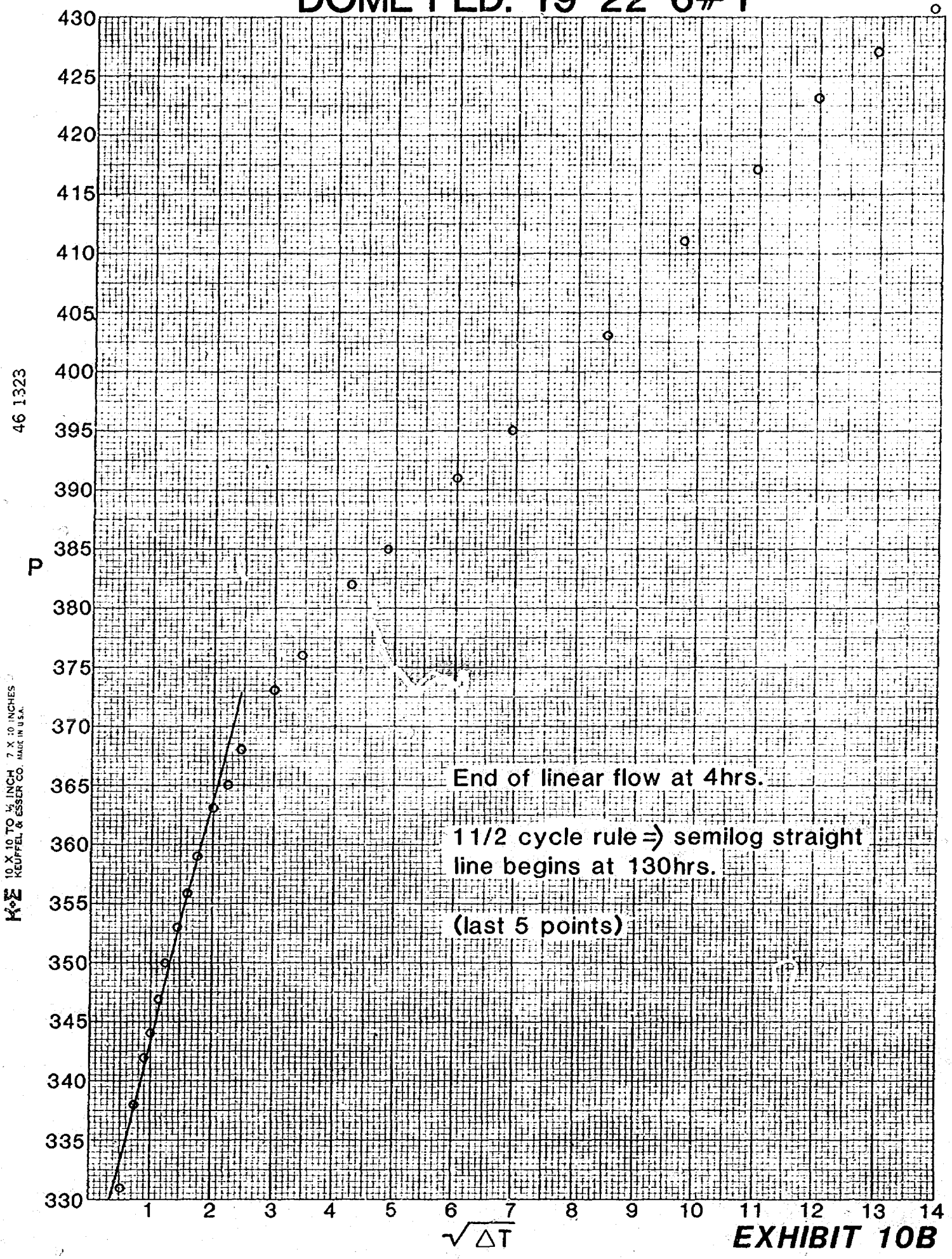


EXHIBIT 10A

DOME FED. 19-22-6#1



46 1323

K&E 10 X 10 TO ½ INCH 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

EXHIBIT 10B

RUSTY CHACRA AREA

WELLS WITH MEASURED UNSTIMULATED RATES

EXHIBIT 11

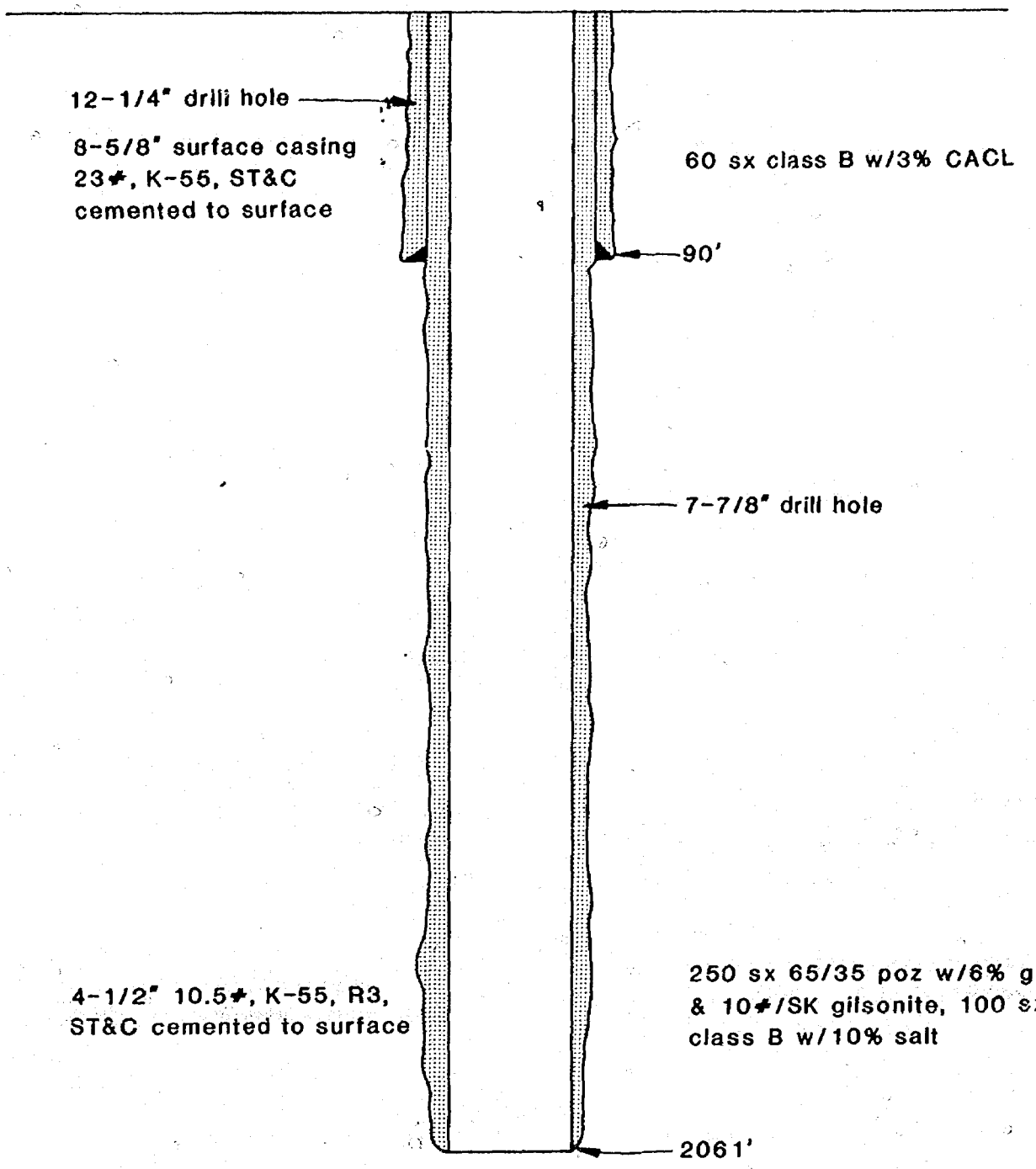
Operator	Well	Location Qtr., Sec., TWP., RNG.				Unstimulated Rate MCFD	3 Hr. Potential After frac MCFD
Dome	Navajo #2	SE	28	22N	7W	0	24
Eng. Prod. Serv.	Tall Pine #1	SE	26	22N	6W	TSTM	54
Dome	Navajo #2	SE	28	22N	6W	0	918
Dome	Navajo #4	SW	28	22N	6W	0	1429
Dome	Federal #3	NE	29	22N	6W	0	1265
Dome	Federal #2	SW	29	22N	6W	TSTM	960
Dome	State #2	NE	32	22N	6W	52	1819
Dome	Navajo #1	NW	34	22N	6W	0	1123
Dome	Navajo #1	NW	35	22N	6W	0	136

TYPICAL CASING DESIGN

RUSTY CHACRA AREA

(Dome/Fed. #1 30-22-6)

EXHIBIT #12



RUSTY NAVAJO 7

Sec. 22, T22N, R7W

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

IP 769

MCF/MONTH

46 6690

1 9 8 7 6 5 4 3 2 10000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY NAVAJO 1

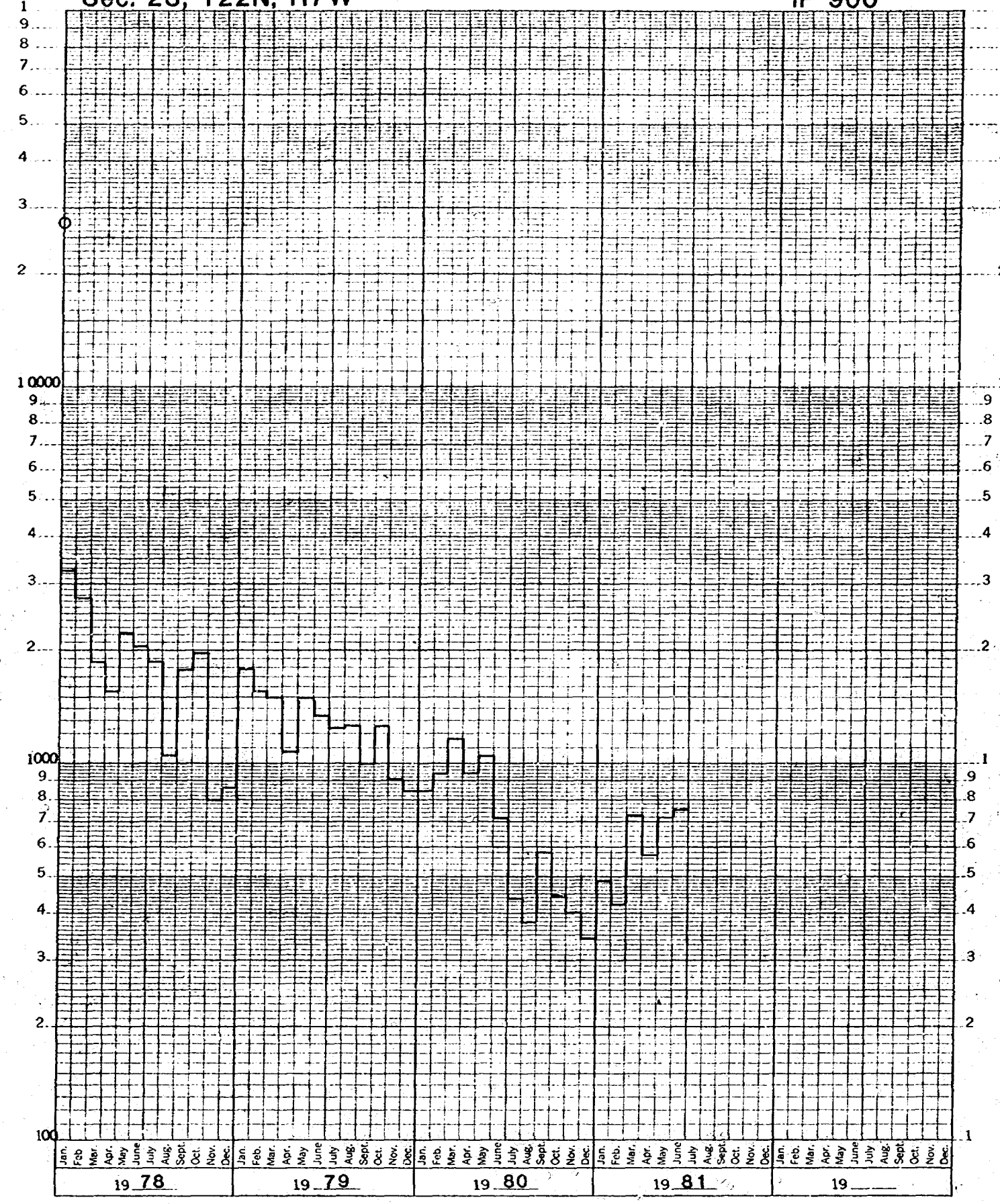
Sec. 23, T22N, R7W

IP 900

MCF/MONTH

46 6690

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.



RUSTY NAVAJO 3

Sec. 23, T22N, R7W

IP 298

46 6690

MCF/MONTH

10000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY FEDERAL 3

Sec. 14, T22N, R7W

IP 1472

MCF/MONTH

46 6690

K•E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

1 9 8 7 6 5 4 3 2 1 0000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

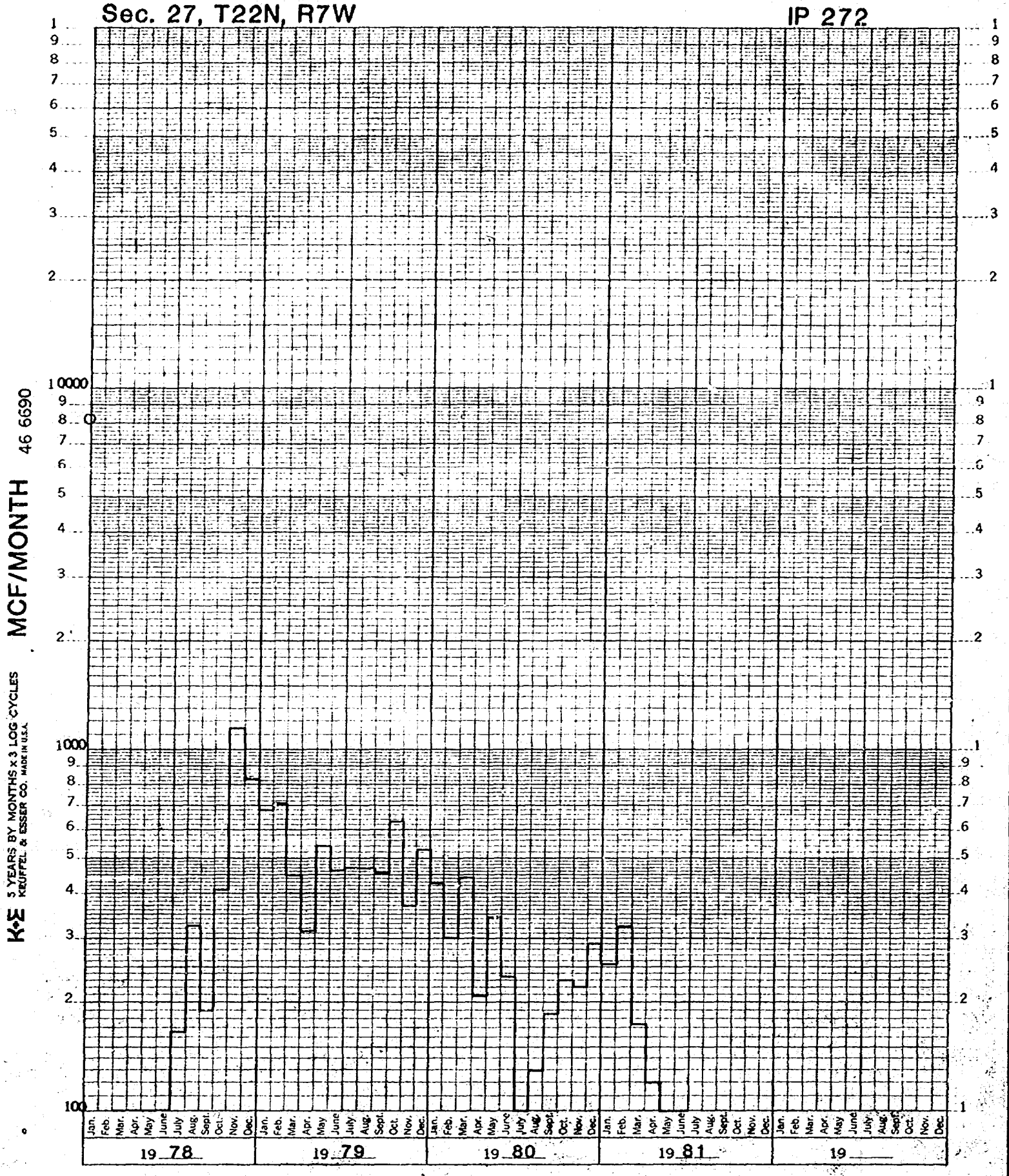
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

RUSTY NAVAJO 6

Sec. 27, T22N, R7W

IP 272



K+E 46 6690

5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

GULF FEDERAL 1

Sec. 13, T22N, R7W

IP 581

MCF/MONTH 46 6690

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

1 9 8 7 6 5 4 3 2 0 1 0000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

RUSTY NAVAJO 4

Sec. 26 T22N, R7W

IP 404

MCF/MONTH

46 6690

10000 9 8 7 6 5 4 3 2

1000 9 8 7 6 5 4 3 2

100

19 78	19 79	19 80	19 81	19
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

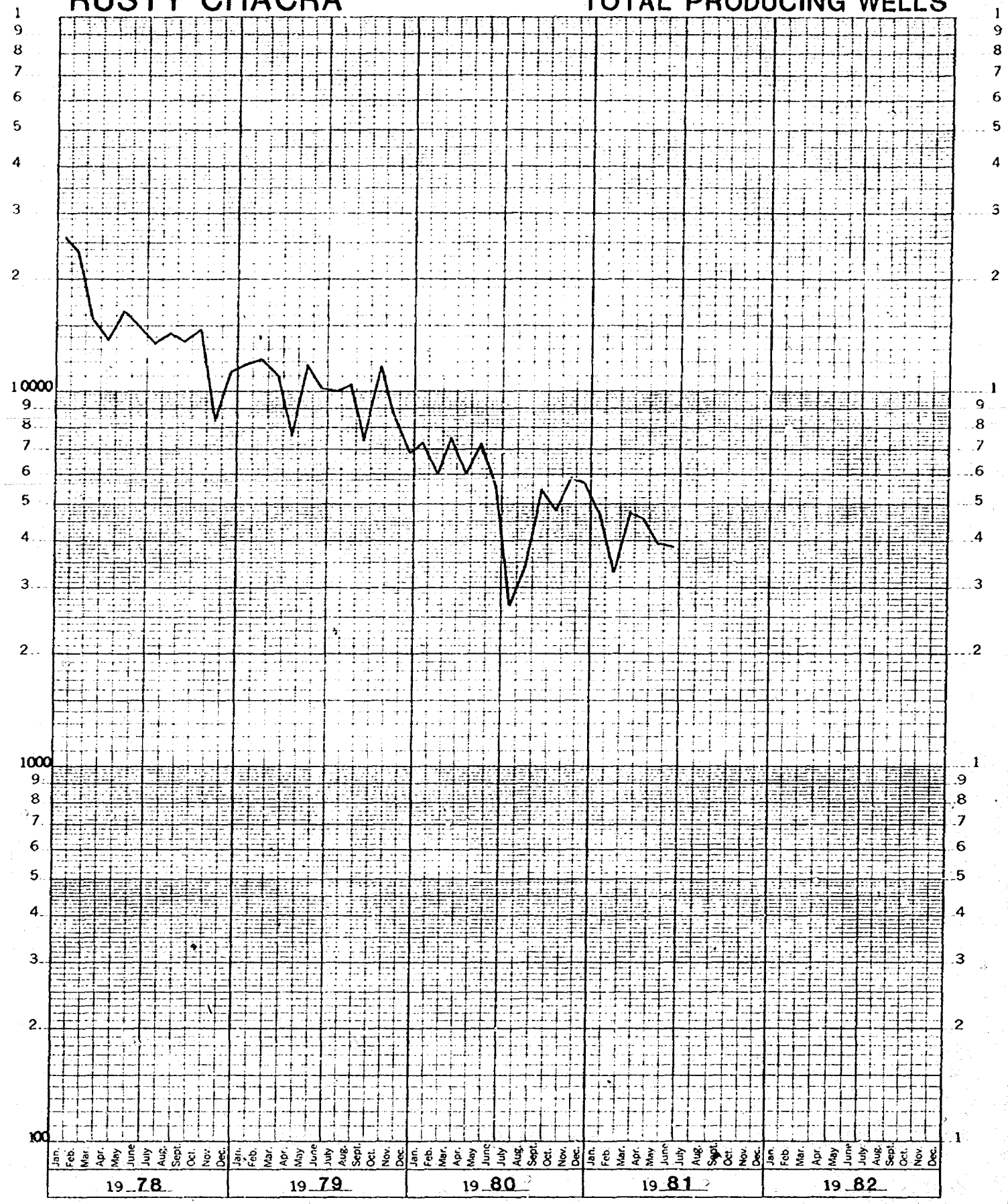
K•E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY CHACRA

TOTAL PRODUCING WELLS

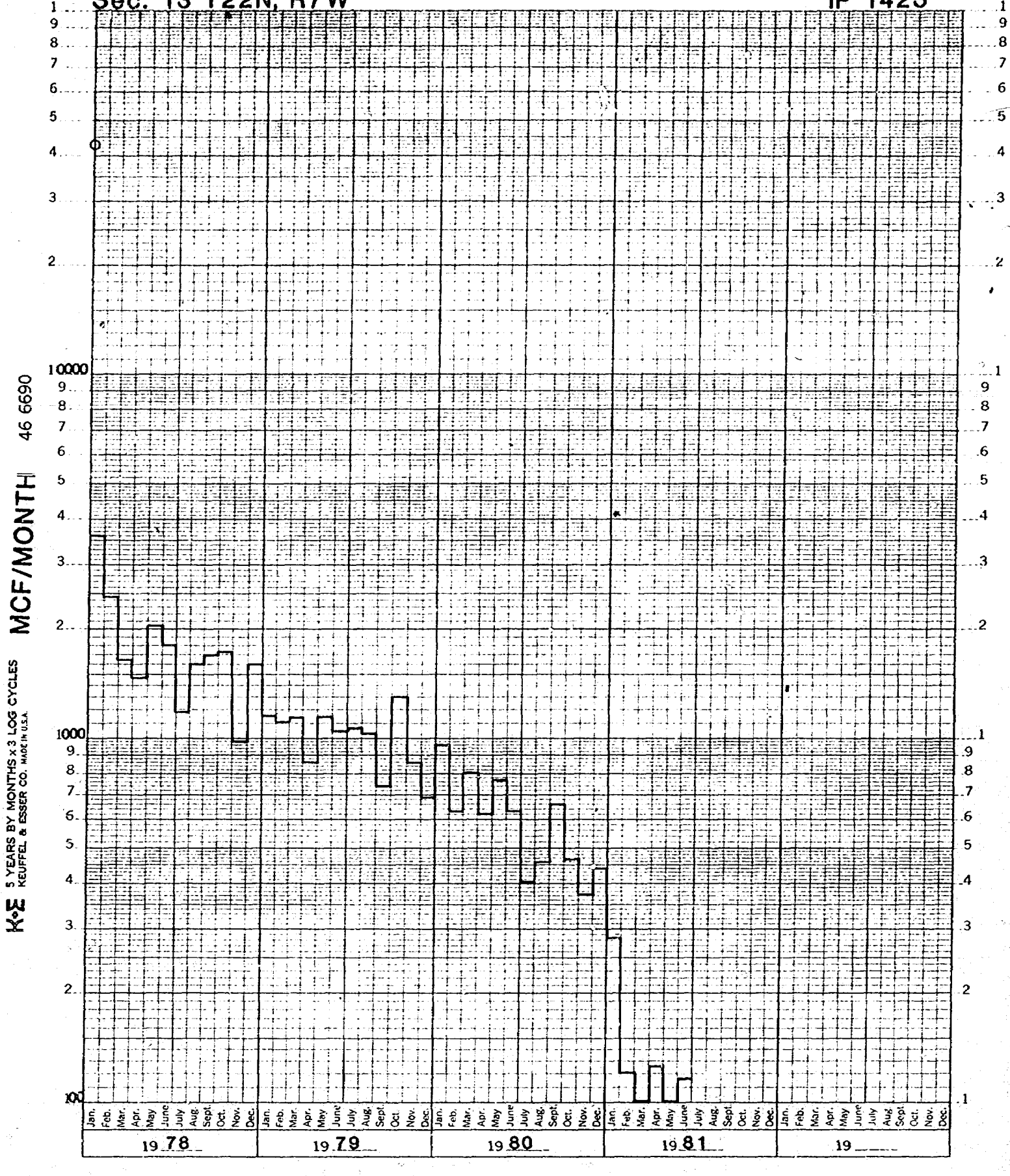
MCF/MONTH 46 6590

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.



RUSTY FEDERAL 4
Sec. 13 T22N, R7W

IP 1423



KE 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY FEDERAL 2
Sec. 14 T22N, R7W

IP 457

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

1 9 8 7 6 5 4 3 2 10000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

RUSTY FEDERAL 1
Sec. 11 T22N, R7W

IP 450

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

10000
1000
100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

RUSTY NAVAJO 5

Sec. 22, T22N, R7W

IP 960

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

19 78	19 79	19 80	19 81	19
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.	Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

GULF FEDERAL 2

Sec. 11, T22N, R7W

IP 700

MCF/MONTH 46 6690

1 0000
9
8
7
6
5
4
3
2
1000
9
8
7
6
5
4
3
2
100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

GULF FEDERAL 3

Sec. 13, T22N, R7W

IP 348

MCF/MONTH

46 6690

1 9 8 7 6 5 4 3 2 10000 9 8 7 6 5 4 3 2 1000 9 8 7 6 5 4 3 2 100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

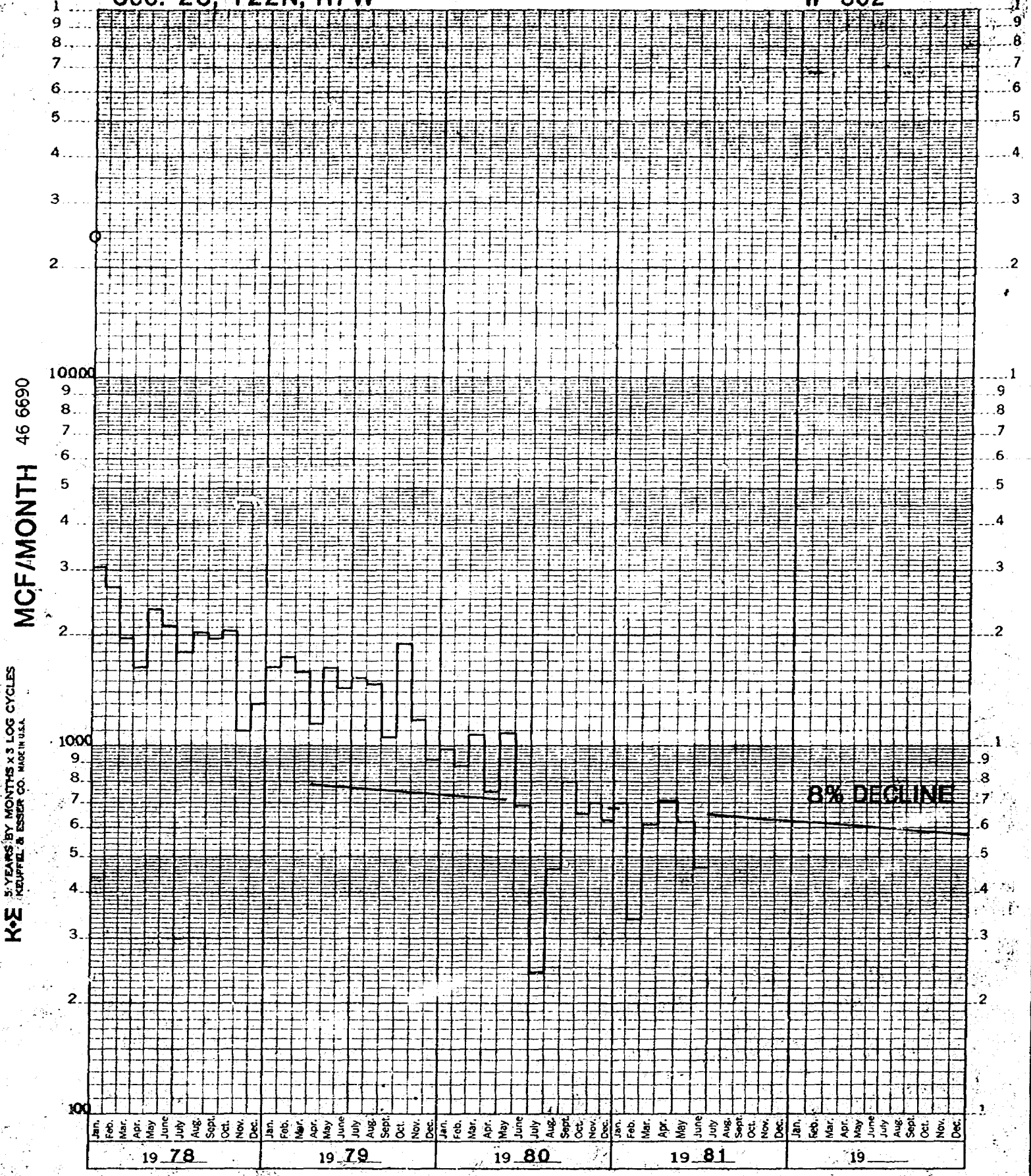
19 78 | 19 79 | 19 80 | 19 81 | 19 ____

K•E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY NAVAJO 2

Sec. 23, T22N, R7W

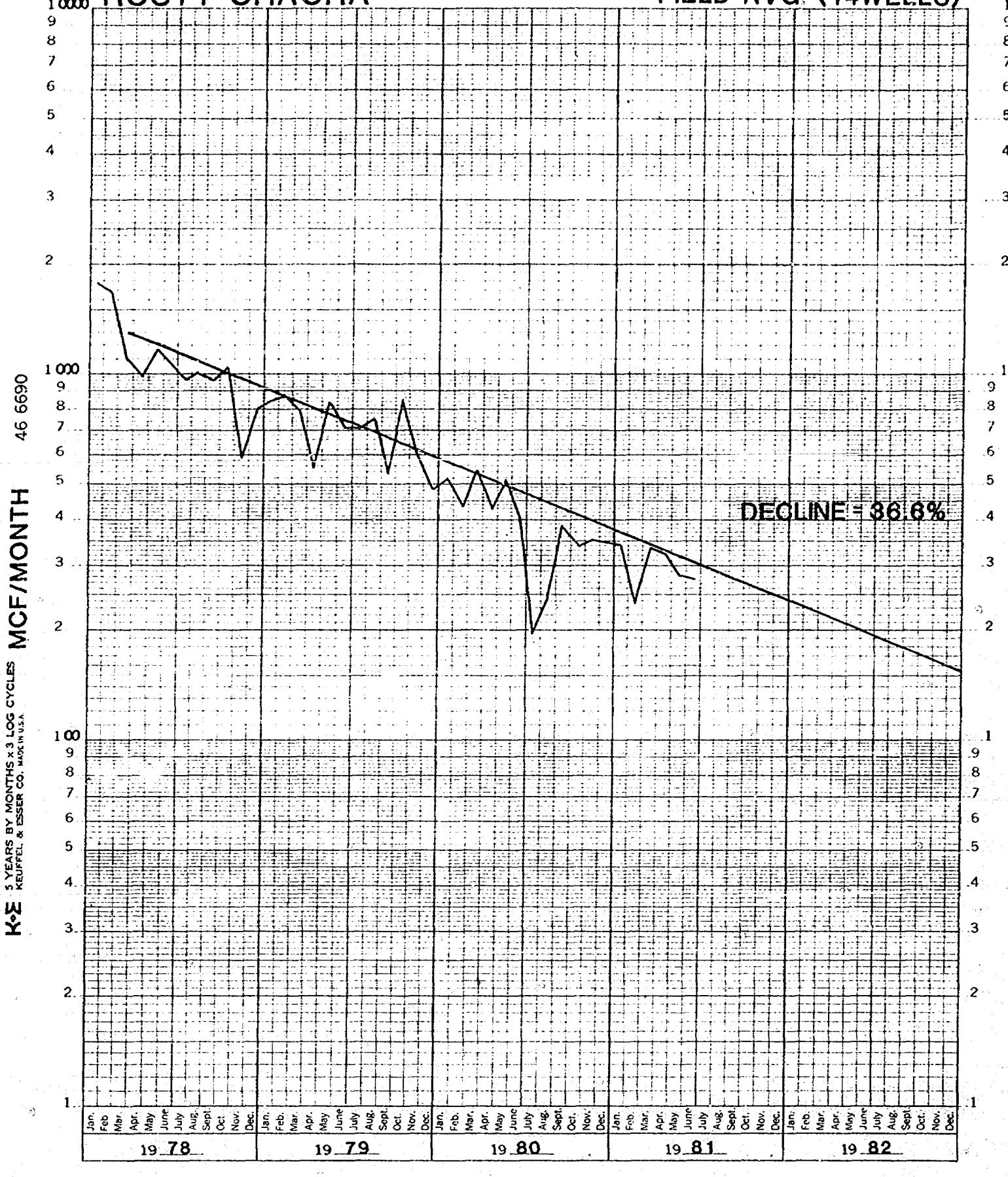
IP 802



K•E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY CHACRA

FIELD AVG. (14WELLS)



K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY CHACRA AVERAGE WELL
Economic Detail

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 18
CASE NO. 730
Submitted by Applicant
Hearing Date 10-21-81

Before Income Tax

Gross Production

	NGPA Section 108							NGPA Section 107				
Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $	MCF/D	MCF/Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $
82	3.42	37640	9360	1385	26895	36	13192	5.44	59790	9360	1385	49045
83	3.90	27827	10296	898	16632	23	8555	5.98	42651	10296	898	31457
84	4.45	17420	11326	493	5602	13	4698	6.58	25764	11326	493	13945
85	4.99	11364	10110	287	968	9	3202	7.24	19316	12458	336	6522
86						7	2521	7.95	16709	13392	265	3052
TOTAL		94251	41092	3063	50096		32168		164231	56832	3378	104022

After Income Tax*

	NGPA Section 108						NGPA Section 107			
Yr	Depreciation $	Investment Credit $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $
82	6291	4194	26895	-99756	-55070	-80336	49045	-77606	-43773	-69482
83	9227		16632	7406	3777	12856	31457	22230	11337	20120
84	8807		5602	- 3206	- 1635	7237	13945	5138	2620	11325
85	8807		968	- 7840	- 3998	4966	6522	-2286	-1166	7687
86	8807						3052	-5755	-2935	5987
TOTAL	41940	4194	50096	-103396	-56926	-55278	104022	-58278	-33916	-24362

* Includes capital costs of $41,940 Tangible and $120,360 Intangible.

RUSTY CHACRA BEST WELL
Economic Detail

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 18A
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

Before Income Tax

	NGPA Section 108					Gross Production		NGPA Section 107				
Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $	MCF/D	MCF/Yr.	Price $/MCF	Net Rev. After Roy $	Operating Expense $	Sev. Tax $	Net Op. Income $
82	3.21*	64235	9360	2521	52354	66	24014	5.44	108839	9360	2521	96958
83	3.90	56239	10296	1815	44127	47	17290	5.98	86200	10296	1815	74089
84	4.45	33580	11326	951	21304	20	9056	6.58	49664	11326	951	37388
85	5.07	30647	12458	761	17428	20	7250	7.24	43736	12458	761	30516
86	5.78	33521	13704	730	19086	19	6956	7.96	46158	13704	730	31724
87	6.59	35156	15074	672	19410	18	6399	8.76	46712	15074	672	30966
88	7.52	36872	16582	618	19672	16	5888	9.64	47273	16582	618	30073
89	8.57	38671	18240	569	19863	15	5417	10.00	45134	18240	569	26325
90	9.77	40559	20064	523	19971	14	4983	10.00	41523	18240	523	22760
91	10.00	38204	20064	481	17659	13	4585	10.00	38201	18240	481	19480
92	10.00	35148	20064	443	14641	12	4218	10.00	35145	18240	443	16462
93	10.00	32336	20064	407	11865	11	3880	10.00	32333	18240	407	13686
94	10.00	29749	20064	375	9310	10	3570	10.00	29747	18240	375	11132
95	10.00	27369	20064	345	6960	9	3284	10.00	27367	18240	345	8782
96	10.00	25180	20064	317	4798	8	3022	10.00	25178	18240	317	6620
97	10.00	23165	20064	292	2809	8	2780	10.00	23163	18240	292	4632
98	10.00	21312	20064	269	980	7	2557	10.00	21310	18240	269	2802
99	10.00	1670	1643	21	6	6	2353	10.00	19606	18240	247	1119
00						6	497	10.00	4144	4054	52	38
TOTAL		603613	289259	12111	302243		117999		771434	293494	12389	465551

*First year assumes NGPA 102 price since well would not qualify for NGPA 108 until second year.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. 8
CASE NO. 7300
Submitted by Applicant
Hearing Date 7300

RUSTY CHACRA BEST WELL
Economic Detail

After Income Tax*

			NGPA Section 108				NGPA Section 107			
Yr	Depreciation $	Investment Credit $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $	Net Income $	Net Taxable Income $	Income Tax $	Cash Flow After Tax $
82	6291	4194	52354	-74297	-42086	-67861	96958	-29693	-19338	-46005
83	9227		44127	34900	17799	26328	74089	64862	33080	41009
84	8807		21304	12496	6373	14931	37388	28580	14576	22812
85	8807		17428	8620	4396	13031	30516	21709	11072	19445
86	8807		19086	10279	5242	13844	31724	22916	11687	20036
87			19410	19410	9899	9511	30966	30966	15793	15173
88			19672	19672	10033	9639	30073	30073	15337	14736
89			19863	19863	10130	9733	26325	26325	13426	12899
90			19971	19971	10185	9786	22760	22760	11607	11152
91			17659	17659	9006	8653	19480	19480	9935	9545
92			14641	14641	7467	7174	16462	16462	8396	8066
93			11865	11865	6051	5814	13686	13686	6980	6706
94			9310	9310	4748	4562	11132	11132	5677	5455
95			6960	6960	3550	3411	8782	8782	4479	4303
96			4798	4798	2447	2351	6620	6620	3376	3244
97			2809	2809	1433	1377	4632	4632	2362	2269
98			980	980	500	480	2802	2802	1429	1373
99			6	6	3	3	1119	1119	570	548
00							38	38	20	19
TOTAL	41940	4194	302243	139943	67177	72766	465551	303251	150464	152787

* Includes capital costs of $41,940 Tangible and $120,360 Intangible.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
EXHIBIT NO. # 20
CASE NO. 7300
Submitted by Applicant
Hearing Date 10-21-81

RUSTY CHACRA
SUMMARY OF
ECONOMIC EVALUATIONS

	AVERAGE WELL		BEST WELL	
NGPA Section	108	107	108	107
Gross Reserves (MMCF)	29.2	32.3	115.3	118.0
Investment (M$)	162.3	162.3	162.3	162.3
BEFORE INCOME TAX				
Undiscounted Cash Flow (M$)	-112.2	-58.3	139.9	303.3
Cash Flow at 15% Discount Rate (M$)	-119.2	-75.6	2.3	109.6
Cash Flow at 20% Discount Rate (M$)	-121.0	-80.0	-18.5	78.8
Rate of Return (%)	0	0	15.5	45.2
Payout (Yrs.)	--	--	5.4	1.9
AFTER INCOME TAX				
Undiscounted Cash Flow (M$)	-55.3	-24.4	72.8	152.8
Cash Flow at 15% Discount Rate (M$)	-67.3	-43.5	-5.4	47.2
Cash Flow at 20% Discount Rate (M$)	-70.5	-48.4	-18.3	29.4
Rate of Return (%)	0	0	13.3	32.3
Payout (Yrs.)	--	--	5.0	2.2

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
AZTEC DISTRICT OFFICE

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

August 14, 1981

Response to Supplement to Info RFL

1000 RIO BRAZOS ROAD
AZTEC, NEW MEXICO 87410
(505) 334-6178

RECEIVED
AUG 17 1981
OIL CONSERVATION DIVISION
SANTA FE

Mr. Richard Stamets
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: Case #7300

Dear Dick:

The information submitted by Dome after the hearing does not indicate that the lower perforations are or were communicating with the upper perforations in the Dome Navajo 20-22-7 #1. If Dome can show that there was communication, they will also need to show that the earlier volume of gas produced from the lower perforations was considered in the "q" value used in the calculations. The "limited entry" technique has been accepted by the industry, however, Dome should submit for the record the tracer surveys, reference literature, etc., to show the effect of the technique in this particular well and in general. If they can supply this information, we should be able to accept their corrected calculated permeability of 0.15 md on exhibit 9A.

Exhibit 8A uses "h" or net pay factor of 52'. Well records show that the Chace Rusty Federal #4 has the following perforations: 1758-62 w/2spf, 1766-68 w/2spf, 1773-81 w/8spf, 1789-93 w/2spf, and 1798-1801 w/2spf, for total of 21' of perforations. As this is not a limited entry completion, industry practice is to consider only the perforated intervals as "net pay." The resulting calculated permeability is 0.331 md. Dome will need to explain why they use a net pay figure of 52' and a supercompressibility factor of 0.94 instead of 0.97 as in the other exhibits.

Exhibit 10A for the Dome Federal 19-22-6 #1 uses an "h" factor of 105'. Well records show the following perforations: 1698'-1744' w/13 jet shots and 1772'-1805' w/19 jet shots for a total of 79'. However, as this is a limited entry completion if we use Dome's criterion of considering the intervals of 10% porosity or greater as net pay we find only 70' of net pay. (See attached copy of log.) Using the 70' as "h" in the Horner equation results in a permeability of .0446 md.

By using the revised permeabilities, we find that the average permeability from the exhibits is .175 md.

If the Horner method of calculating permeability is used in future hearings, the witnesses should supply for reference the data to support the figures which are used in the Horner equation. They should also supply the statistical data to show that sampling techniques used in selecting the number of samples are valid. For example: Do three wells out of seventy nine constitute a statistically representative sample? If not, to what degree?

I recommend that unless Dome can supply the data to justify their exhibits, their application be denied.

Yours truly

Frank T. Chavez
District Supervisor

Done Feb 19-22-6 #1

1700

1800

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION

RECEIVED
OCT 02 1981
OIL CONSERVATION DIVISION
SANTA FE

October 1, 1981

Mr. R. L. Stamets
Oil Conservation Division
State of New Mexico
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: NMOCD Case No. 7300 - Application of Dome Petroleum Corporation for Designation of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico

Dear Mr. Stamets:

I would appreciate it if you would schedule the referenced case for rehearing at the next available date, which I understand is October 21, 1981.

I very much appreciate your cooperation and assistance to me in this matter.

Sincerely,

KENNETH BATEMAN

Kb/bah

cc: Mr. K. F. Tracey
Senior Reservior Engineer
Dome Petroleum Corp.

Mailing Address: P.O. Box 787, Santa Fe, N.M. 87501
Street Address: 220 Otero St., Santa Fe, N.M. 87501 (505) 982-4374

L. C. White
Sumner S. Koch
William Booker Kelly
John F. McCarthy, Jr.
Kenneth Bateman
Benjamin Phillips
C. Emery Cuddy, Jr.
Larry C. White
Forrest S. Smith
Daniel H. Friedman
John N. Patterson
Paula Tackett
Filmore E. Rose

Attorneys and Counselors at Law

CASE 7298: (This case will be dismissed.)

Application of Amoco Production Company for an NGPA determination, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks a new onshore reservoir determination in the Morrow formation for its Lancaster Springs Com Well No. 1 in Unit I of Section 1, Township 22 South, Range 26 East.

CASE 7299: (This case will be dismissed.)

Application of Amoco Production Company for an NGPA determination, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks a new onshore reservoir determination in the Morrow formation for its State IL Com Well No. 1 in Unit C of Section 3, Township 19 South, Range 24 East.

CASE 7300: Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Chacra formation underlying portions of Townships 21 and 22 North, Ranges 5, 6, and 7 West, containing 73,018 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 7301: In the matter of the hearing called by the Oil Conservation Division on its own motion for an order creating, redesignating, and extending vertical and horizontal limits of certain pools in Chaves, Eddy, Lea, and Roosevelt Counties, New Mexico:

(a) CREATE a new pool in Lea County, New Mexico, classified as a gas pool for Morrow production and designated as the East Lusk-Morrow Gas Pool. The discovery well is Grace Petroleum Corporation West Tonto Federal Com Well No. 1 located in Unit L of Section 24, Township 19 South, Range 32 East, NMPM. Said pool would comprise:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 24: W/2

(b) CREATE a new pool in Roosevelt County, New Mexico, classified as an oil pool for Mississippian production and designated as the Peterson-Mississippian Pool. The discovery well is Enserch Exploration, Inc. Finley Well No. 1 located in Unit A of Section 6, Township 5 South, Range 33 East, NMPM. Said pool would comprise:

TOWNSHIP 4 SOUTH, RANGE 33 EAST, NMPM
Section 28: SW/4
Section 29: S/2
Section 32: W/2

TOWNSHIP 5 SOUTH, RANGE 33 EAST, NMPM
Section 5: NW/4
Section 6: NE/4

(c) CREATE a new pool in Lea County, New Mexico, classified as a gas pool for Wolfcamp production and designated as the Salado Draw-Wolfcamp Gas Pool. The discovery well is Amoco Production Company State GR Well No. 1 located in Unit G of Section 17, Township 26 South, Range 33 East, NMPM. Said pool would comprise:

TOWNSHIP 26 SOUTH, RANGE 33 EAST, NMPM
Section 17: E/2

(d) CREATE a new pool in Lea County, New Mexico, classified as a gas pool for Strawn production and designated as the Talco-Strawn Gas Pool. The discovery well is American Trading and Producing Corporation Talco Unit Well No. 1 located in Unit H of Section 11, Township 26 South, Range 35 East, NMPM. Said pool would comprise:

TOWNSHIP 26 SOUTH, RANGE 35 EAST, NMPM
Section 11: E/2

(e) REDESIGNATE the Lusk-Seven Rivers Pool in Lea County, New Mexico, to the North Lusk-Seven Rivers Pool described as:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 3: All

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 11, 1981

TO: R. L. Stamets

FROM: M. E. Stogner M.E.

SUBJECT: Case #7300 - Application of Dome Petroleum Corporation for Designation of a Tight Formation, Sandoval County, New Mexico

In reviewing the evidence submitted in Case No. 7300 and the supplemental information concerning this case, it is my recommendation that unless Dome Petroleum Corporation can supply the Division the following supplemental data, their application be denied.

1.) Dome should supply for reference the data to support the figures which were used in the Horner equations.

2.) Dome set the criterion of considering the intervals of 10% porosity or greater as net pay. However, the figures used in the calculations do not correspond to the 10% porosity interval represented on the density -gamma-ray logs provided. Any future calculations should consider "h" using this 10% criterion only.

3.) Since this relatively large area has a number of producing wells or wells capable of producing, Dome should supply pressure data and permeability calculations from more than just three of these wells

4.) For a more complete evaluation of this case, it would be helpful if Dome would furnish an economic report in accordance to Section 107, (D)(2)(d) of the NGPA, showing that the incentive price is necessary to provide reasonable incentive for production of the natural gas from the formation due to extraordinary risks or costs associated with such production.

CASE 7392: Application of Sam H. Sloddy, for an unorthodox gas well location in the Oil-Potash Area, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the location of a Pennsylvanian well to be drilled 660 feet from the North and East lines of Section 26, Township 20 South, Range 32 East, Oil-Potash Area, the N/2 of said Section 26 to be dedicated to the well.

CASE 7393: Application of Uriah Exploration Incorporated for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Cisco, Canyon and Morrow formations underlying the W/2 of Section 13, Township 22 South, Range 24 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7394: Application of Supron Energy Corporation for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of a Pennsylvanian well to be drilled 467 feet from the North line and 1650 feet from the West line of Section 13, Township 22 South, Range 24 East, the N/2 of said Section 13 to be dedicated to the well.

CASE 7395: Application of Curtis J. Little for Designation of a Tight formation, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Pictured Cliffs formation underlying portions of Townships 25 and 26 North, Ranges 6 and 7 West containing a total of 14,400 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 7300: (Reopened and Readvertised)

Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Chacra formation underlying portions of Townships 21 and 22 North, Ranges 5,6, and 7 West, containing 73,018 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 7352: (Continued from September 23, 1981, Examiner Hearing)

Application of Yates Petroleum Corporation for designation of a tight formation, Eddy County, New Mexico. Applicant, in the above-styled cause, pursuant to Section 107 of the Natural Gas Policy Act 18-CFR Section 271. 701-705, seeks the designation as a tight formation of the Permo-Penn formation underlying all of the following townships:

Township 17 South, Ranges 24 thru 26 East;

18 South, 24 and 25 East,

19 South, 23 thru 25 East;

20 South, 21 thru 24 East;

20 1/2 South, 21 and 22 East;

21 South, 21 and 22 East;

Also Sections 1 thru 12 in 22 South, 21 and 22 East,

All of the above containing a total of 315,000 acres more or less.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

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GOVERNOR
LARRY KEHOE
SECRETARY

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

September 11, 1981

TO: R. L. Stamets

FROM: M. E. Stogner M.E.

SUBJECT: Case #7300 - Application of Dome Petroleum Corporation for Designation of a Tight Formation, Sandoval County, New Mexico

In reviewing the evidence submitted in Case No. 7300 and the supplemental information concerning this case, it is my recommendation that unless Dome Petroleum Corporation can supply the Division the following supplemental data, their application be denied.

1.) Dome should supply for reference the data to support the figures which were used in the Horner equations.

2.) Dome set the criterion of considering the intervals of 10% porosity or greater as net pay. However, the figures used in the calculations do not correspond to the 10% porosity interval represented on the density -gamma-ray logs provided. Any future calculations should consider "h" using this 10% criterion only.

3.) Since this relatively large area has a number of producing wells or wells capable of producing, Dome should supply pressure data and permeability calculations from more than just three of these wells

4.) For a more complete evaluation of this case, it would be helpful if Dome would furnish an economic report in accordance to Section 107, (D)(2)(d) of the NGPA, showing that the incentive price is necessary to provide reasonable incentive for production of the natural gas from the formation due to extraordinary risks or costs associated with such production.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL AND CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7300
ORDER NO. R-6874

APPLICATION OF DOME PETROLEUM
CORPORATION FOR DESIGNATION OF
A TIGHT FORMATION, SANDOVAL
COUNTY, NEW MEXICO

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on July 2, 1981, at Santa Fe, New Mexico before Examiner Richard L. Stamets and was readvertised and reopened at a hearing held at 9 a.m. on October 21, 1981, at Santa Fe, New Mexico before examiner Richard L. Stamets.

NOW, on this _____ day of _____, 1981, 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, Dome Petroleum Corporation, requests that the Division in accordance with Section 107 of the Natural Gas Policy Act, and 18 C.F.R. §271.703, recommend to the Federal Energy Regulatory Commission that the Chacra Formation underlying the following lands situated in Sandoval County, New Mexico, hereinafter referred to as the Chacra formation, be designated as a tight formation in the said Federal Energy Regulatory Commission's regulations:

Case No. 7300
Order No. _____

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections: 1 through 18: All
Sections: 20 through 27: All
Sections: 35 through 36: All

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 4: All
Sections: 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 36: All

Containing 73,017.58 acres more or less.

(3) That the Chacra formation underlies all the above described lands; that the formation consists of fine grained and clay filled transitional shaly sands and silt stones; that the top of such formation is found at an average depth of 1658 feet below the surface of the area set forth in Finding No. 2 above; that the thickness of said formation varies with an average thickness of 300 feet within said area.

(4) That the type section for the Chacra formation for the proposed tight formation designation is found at a depth of approximately 1946 feet to 2340 feet on the Birdwell density and neutron and induction electric logs dated 4/5/80 and 9/6/80 respectively, of the Dome Federal 20-22-6 No. 2 Rusty Chacra located in Unit No. P of Section 20, Township 22 North, Range 6 West, N.M.P.M. Sandoval County, New Mexico.

(5) That the Chacra formation underlying the above described lands has been penetrated by 70 wells of which only fourteen are currently producing natural gas in commercial quantities from the Chacra formation.

(6) That the evidence presented in this case demonstrated that no well formerly or currently completed in the Chacra formation within the proposed area may reasonably be presumed to have exhibited permeability gas productivity or crude oil productivity in excess of the following parameters:

(a) average in situ gas permeability throughout the pay section of 0.1 millidarcy; and

(b) stabilized production rates, without stimulation, against atmospheric pressure, as found in the table set out in 18 C.F.R. §271.703-(c)(2)(B) of the regulations; and

(c) production of more than five barrels of crude oil per day.

(6) ~~(7)~~ That based on an analysis of available data from existing wells within the proposed area and utilizing generally and customarily accepted petroleum engineering techniques and measurements:

(a) the estimated average in situ gas permeability throughout the pay section of the Chacra formation is expected to be 0.1 millidarcy or less; and

(b) the stabilized production rate, against atmospheric, of wells completed for production in the Chacra formation, without stimulation, is not expected to exceed production levels determined by reference to well depth, as found in the table set out in 18 C.F.R. §271.703(c)(2)(B) of the regulations; and

(c) no well drilled into the Chacra formation is expected to produce, without stimulation more than five barrels of crude oil per day.

(7) ~~(8)~~ That the Chacra formation underlying the area described in Paragraph 2 hereof is not being developed by infill drilling.

(8) ~~(9)~~ That the evidence presented in this case demonstrated that the application of incentive pricing is reasonably necessary to stimulate further development of the proposed tight formation underlying the area described in Paragraph 2 hereof.

(9) ~~(10)~~ That within the proposed area there is a recognized aquifer being the Ojo Alamo, found at a depth of from 500 feet to 1100 feet or approximately 1158 to 558 feet above the Chacra formation.

(10) ~~(11)~~ That existing State of New Mexico and Federal Regulations relating to casing and cementing of wells will assure that development of the Chacra formation will not adversely affect the said aquifers.

(11) ~~(12)~~ That the Chacra formation should be recommended to the Federal Energy Regulatory Commission for designation as a tight formation.

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. §271.703 of the regulations that the Chacra formation underlying the following described lands in Sandoval County, New Mexico be designated as a tight formation:

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections: 1 through 18: All
Sections: 20 through 27: All
Sections: 35 through 36: All

Case No. 7300
Order No. _____

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 4: All
Sections: 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 36: All

(2) The jurisdiction of this cause is hereby 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

- Case #7300 Dome Light Gas Sample -

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

CASE 7300

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: W. Perry Pearce, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: Ken Bateman, Esq.
WHITE, KOCH, KELLY, & McCARTHY
220 Otero Street
Santa Fe, New Mexico 87501

I N D E X

KEVIN TRACY

Direct Examination by Mr. Bateman 4

Questions by Mr. Chavez 20

E X H I B I T S

Applicant Exhibit Thirteen, Build-up Data 4

Applicant Exhibit Fourteen, Well Cost Estimate 12

Applicant Exhibit Fifteen, Operating Costs 13

Applicant Exhibit Sixteen, Economic Data 14

Applicant Exhibit Seventeen, Graphs 17

Applicant Exhibit Eighteen, Economic Info. 18

Applicant Exhibit Nineteen, Economic Info. 18

Applicant Exhibit Twenty, Summary 18

MR. STAMETS: We'll call next Case 7300. It has been heard and previously taken under advisement, but it's being reopened today for submittal of some additional information.

MR. PEARCE: And it is application of Dome Petroleum Corporation for designation of a tight formation, Sandoval County, New Mexico.

MR. BATEMAN: Mr. Examiner, I'm Ken Bateman of White, Koch, Kelly, and McCarthy, and I have one witness.

(Witness sworn.)

MR. BATEMAN: Mr. Examiner, inasmuch as this case has been -- was heard previously on July the 2nd, I'd like to dispense with the qualifications of the witness. We have the same witness.

MR. STAMETS: The same witness who was previously qualified?

MR. BATEMAN: Correct.

MR. STAMETS: Yes, he is still considered qualified.

MR. BATEMAN: It is our intention to present additional data concerning the permeability calcula-

tion as well as the economic data which was presented at the previous hearing on July 2nd, 1981.

KEVIN TRACY

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

DIRECT EXAMINATION

BY MR. BATEMAN:

Q. Would you again, however, state your name for the record?

A. Kevin Tracy.

Q. And your place of employment and position?

A. I'm a Senior Reservoir Engineer for Dome Petroleu, Denver, Colorado.

Q. In connection with this application have you made calculations of permeability, average permeability for the area in question?

A. Yes, I have, and it was presented at the last hearing.

Q. Let's proceed, then, with what's been marked Exhibit Thirteen, A, B, and C, and would you please elaborate on the detail of the information used for calcu-

lating the in situ permeability in the area?

A. Exhibits Thirteen A, B, and C are additional detail of -- to show how the permeability number was calculated for each of the three wells that had extended pressure build-up tests.

Thirteen A concerns the Chase Rusty Federal No. 4. I'd like to first list all the attachments here.

Attached is an open flow potential test write-up; a copy of the Horner build-up plot from the last hearing; a copy of the pressure versus square root of Delta T plot from the last hearing; the field data of pressure and time; a copy of the gamma ray density log section over the Chacra zone; and copies of several correlations of natural gas properties used in obtaining some of the values in the equation for calculating permeability.

Now, I'll go through what the significance of those attachments are.

The field data is included to show the gas rate, time and casing pressures that are recorded during the test of this well.

The one point test write-up is included to show where the formation temperature and the gas gravity came from. Formation temperature being 92 degrees Fahrenheit,

which was converted to degrees ranging in the equation.

The gas gravity of .626 was used in the correlations of natural gas properties to obtain some other properties of gas.

Viscosity of the gas was evaluated at an average pressure and the average being the sum of the flowing pressure and final shut-in pressure divided by two; in the case of this well, 380 psi.

The gas properties were evaluated at that pressure.

Knowing the reservoir temperature, the pressure of interest, and the gas gravity, one of the correlation charts attached is used to get a gas viscosity; in this case, .012 centipoise.

In the equation for permeability the z factor is the real gas deviation factor and in order to get that number pseudo critical temperature and pseudo critical pressure of 367 degrees R and 670 psi were obtained from the correlation charts. Using those and the average pressure and the reservoir temperature previously shown we get the pseudo reduced pressure and pseudo reduced temperature.

Using those two numbers you go on to another correlation chart, also attached, to get the z factor of .94.

In the equation q is the producing gas rate in Mcf per day and this well's build-up was 627 Mcf per day, which is the last measured rate prior to shutting in the well for the pressure build-up.

T is the producing time in hours and was corrected for any fluctuations in producing rate by taking the cumulative production during the test, dividing by the final rate and multiplying by 24 hours per day.

Delta T is the shut-in time read directly from the field data sheet.

H in the equation is the thickness of pay contributing to production. In this case it was 52 feet. This number was taken from the log evaluation of the Chacra in the well in which any porous zones above 8 percent porosity were included, subtracting any shale breaks.

And it's my opinion that an 8 percent cutoff is reasonable in this area in that zones of 8 percent porosity are contributing to production.

I'd like to go now to the additional detail for pressure build-up analysis on the Dome Navajo 20-22-7 No. 1.

And included as attachments to this write-up are the field data; a copy of the gamma ray density log; the Horner plot from the previous hearing; the pressure

versus square root of Delta T plot; and eight gas analyses for Chacra Wells in the area.

The field data was used once again for the pressure and time use on the plots. Flowing time for the purposes of calculating superposition time in the Horner plot was cumulative production during the test divided by the final flow rate times 24, to get 8.72 hours.

Since a gas analysis was not available for this particular well, the average from eight other gas analyses in the area was used for gas gravity. An average of .63 was obtained.

Using .63 a pseudocritical pressure of 367 degrees -- well, excuse me, let me go back. Pseudocritical temperature and pseudocritical pressure of 367 degrees R and 670 psia were obtained. An average pressure was determined to be 362 psi by averaging the flowing pressure and final shut-in pressure.

The reservoir temperature was assumed to be the same as that recorded during the pressure build-up test in the Dome Federal 19-22-6 No. 1, which was 166 degrees. That was converted to degrees to get 626 degrees R.

Pseudoreduced temperature and pseudo-reduced pressure were then calculated and used in a correlation chart to get the real gas deviation factor of .97.

Using a different correlation chart the gas viscosity of .012 centipoise was obtained.

Q, the gas production rate in Mcf per day was the final recorded rate before shutting in the well; in this case, 101 Mcf per day.

And Delta T in the equation was the shut-in time, which was taken directly from the field data.

Formation thickness contributing to production was determined to be 100 feet for this well by adding up the permeable zones with porosity greater than 8 percent, as taken off the gamma ray density log.

In this particular well there is a bridge plug at 1525, which isolates two sets of perforations in the wellbore. The pay below that bridge plug was also included because we felt that after fracture stimulation of the upper zone communication was re-established with the lower perforations.

During prior operations in the well communication was shown between upper perfs and lower perfs during squeeze operation. After squeezing the upper perfs were re-opened and the well was fracture stimulated.

However, if you just include the pay above the bridge plug, which is 41 feet in this case, the permeability for the well of .115 millidarcy is obtained,

which averaged with the other two is still below the tenth of a millidarcy requirements for tight gas incentive pricing.

And the last write-up is additional detail for pressure build-up analysis for the Dome Federal 19-22-6 No. 1, and included as attachments to that are once again the Horner plot; the plot of pressure versus the square root of Delta T; the field data; and a copy of the gamma ray density log.

Flow rates,bottom hole pressure, bottom hole temperature; times were taken from the field data sheet.

Flowing time for the purposes of calculating superposition time in the Horner plot is calculated by dividing the cumulative production during the test by final flow rate times 24 to get 10.26 hours.

Since the gas analysis was not available for this well, the previous average of eight gas analyses in the area was used in the correlation charts of gas properties

Pseudocritical temperature and pseudocritical pressure of 367 and 670 degrees R and psia were obtained. An average pressure for evaluating gas properties of 671 psi was obtained by averaging the flowing pressure and the final shut-in pressure.

A reservoir temperature of 166 degrees Fahrenheit was converted to 626 degrees R and this temperature

and average pressure were used to -- with the pseudoreduced temperature and pseudoreduced pressure in order to get the real gas deviation factor of .97.

Gas viscosity was estimated at the average pressure to be .0121 centipoise.

The gas flow rate used in the equation of permeability was 275 Mcf per day, which is the final rate reported before the well was shut-in.

And Delta t in the plots was the shut-in time which was also taken directly from the field data.

Formation thickness used in the equation for this well was 105 feet, which was determined from the gamma ray density log by adding up the porous zones with porosity greater than eight percent.

Q. Were there any other wells available in this area for analysis on the Horner plot basis?

A. No other wells had pressure build-ups of sufficient time to reach the straight line on a Horner build-up plot, which takes from eight to ten days in these tight reservoirs.

Q. The length of time is a factor of the tight formation, I take it?

A. Yes.

Q. In your opinion is a Horner plot a reliable

method of estimating the in situ permeability?

A. In my opinion it's the best method of measuring in situ permeability, since it is taken at reservoir conditions and we don't have to correct for them or estimate the effect of water saturation or overburden pressure.

Q. Again for the record, what was your estimate of the average in situ porosity in this area?

A. You mean permeability?

Q. Permeability, excuse me.

A. .07 millidarcy.

Q. And do you believe that's a reliable average for all the wells in question?

A. I believe it is for the reason that the three wells that we have extended pressure build-up tests on are in the middle of the field and, if anything, would represent some of the better part of the reservoir.

Q. Now, with Exhibit Number Fourteen, we've prepared a well cost estimate in this area.

A. Yes. The Exhibit Fourteen is a well cost estimate to drill and complete a Chacra well within our application area, assuming that it would be drilled the first half of next year.

Of significance on this cost estimate sheet is the total well cost of $162,300. The $30,000 stimu-

lation treatment cost estimate, which is the cost for the fracture and stimulation of the well, represents a signficant part of the well costs, and also that, as later we'll see, the tangibles and intangibles split becomes important in the economics of the well; the intangible being $120,360; the tangible being $41,940.

Q. Have you calculated the detail of operating costs?

A. Yes. Exhibit Fifteen is the detail of what our estimated operating costs will be when we start producing the wells in this area. If I can just go down it, in dollars per well per month we've estimated $120 for lease operator; $36 for vehicle operation and repair; compression costs, as far as operating a compressor, allocated back to each well would be $418; maintenance of the compressor $70 per well per month; pumping unit operation $15 per month; we expect to have to pump the water off these wells to make them -- to get them to produce anything at all; and well repair and maintenance $125 per month. That's taken from $1500 per year per well average for pumping unit repair and any type of small acid jobs that might be required.

The total then would be rounded off at $780 per well per month.

Q. You have wells in the area that are not

currently producing, is that correct?

A. That's correct. We have 20 wells in the area that we operate that are waiting on a gathering system.

There's a total of 70 wells that have tested the Chacra in the area, of which only 14 are now on production.

Q. Would you proceed then with what's been marked Exhibit Sixteen and state what your economic assumptions are?

A. Exhibit Sixteen shows the economic assumptions used in evaluating these wells.

First of all, we show gas prices and how we forecast them to increase. We show three categories of gas, NGPA Section 102, which is new well gas, with an actual October, 1981 price of $2.91. In our forecasts shown in the next few tables we escalate that 1 percent per month until 1982 and then we increase that gas price with inflation plus 4 percent until $10 an Mcf is reached, at which time the gas price is held constant.

The next category of gas in NGPA Section 108, which is stripper well gas, for an actual October price of $3.116 per Mcf. Actually it's dollars per million BTU but we've assumed 1000 BTU gas. The escalation would be the

same as NGPA 102.

The third category is NGPA Section 107, which is tight well gas, with an actual October '81 price of $5.03, roughly, per Mcf. We've escalated that 1 percent per month until 1982. Then we escalate it with inflation only until $10 per Mcf is reached.

And throughout our forecasts here we assumed inflation to be 10 percent per year beginning in 1982.

Operating costs were inflated at that 10 percent per year rate until the gas prices peaked at $10 an Mcf; then they also were held constant.

Okay, tangible drilling costs, we depreciated over a five year life by means of 150 percent declining balance changing to a straight line depreciation method in the second year.

Investment tax credit of 10 percent was also included in the evaluation.

As far as taxes, we've included State severance tax on gas of 12.6 cents per Mcf; Federal Income Tax was assumed to be 46 percent, which is the corporate tax rate; and a State income tax of 5 percent was also included.

For the purpose of the forecast shown here, we assume 100 percent working interest with total royalty burdens 16-2/3rds percent, which is representative for this

area.

Q. Did you calculate a production decline?

A. Yes, for analogy we have plotted the declines of all the fourteen producing wells in the area that are operated by Chase. Those are all shown as a package as Exhibit Seventeen. Of particular significance is the field average for the fourteen wells, which shows gas rate in Mcf per month versus time, and these wells began production in the beginning of 1978, and we've plotted through mid-year 1981.

The average well started production at 58 Mcf per day and currently on a daily average is only 9 Mcf per day. The decline rate shown here is 36.6 percent per year.

Another curve that is used in our evaluation is a plot of the well with the best cumulative production to date, and that's the Rusty Navajo No. 2.

This production forecast -- well, actual production was used in our forecast with 8 percent decline after mid-'81.

The initial potential on the 3-hour test is shown in the upper righthand corner for all these individual wells. In this case it was 802 Mcf per day, which plotted on this curve is 24-million per month, which is sig-

nificantly above what the well actually stabilized at for the first month.

Q. So then you've based your economic projections both on an average well basis and on a best well basis, is that correct?

A. That's correct.

Q. It's calculated from the production decline figures which you've just testified to?

A. That's correct.

Q. You've also calculated them based on a before income tax and an after tax basis, is that also correct?

A. Right.

Q. And you've compared Section 108 pricing with Section 107, the tight gas pricing, is that correct?

A. That's right.

Q. Will you state, then, for the Examiner what your conclusions are with respect to necessity for price incentives in this particular area?

A. Well, it becomes very clear that incentive pricing is needed to give a reasonable rate of return, even on our best well basis.

On the average well production forecasts the well won't pay out either with stripper gas prices or tight gas prices.

So a net loss in both cases.

Q. Do you expect by stimulation methods to achieve production greater than the average well figures that you have here?

A. Well, when we -- when Dome first got involved in the area we felt confident that we could do at least as well as these existing Chase operated wells, but we didn't have a lot of production decline history to look at and as time went on we saw that decline was steeper than we were forecasting for our wells and we're still hopeful that the changes we've made in stimulation procedures and in operating techniques will cause our wells to produce at rates closer to the best well case rather than the average; however, there is certainly great risk that ours would be no better than the average well.

Q. The economic forecast is contained in Exhibits Eighteen, Nineteen A and Nineteen B, is that correct?

A. That's correct.

Q. Would you refer to Exhibit Twenty and state what -- or give a summary of your evaluation, please?

A. Okay. A couple of the economic yardsticks used by most companies to evaluate a prospect or a well, a producing well in this case, are the after income tax discounted cash flow, and we show cash flow discounted 15 per-

cent and at 20 percent for the average well case and the best well case, both at the two pricing schemes involved.

The average well case has negative discounted cash flow at both 15 and 20 percent in both pricing cases.

The best well, using stripper gas prices, has a negative cash flow at 15 percent and 20 percent, while with tight gas pricing it would have a positive cash flow at both of those discount rates.

The rate of return on the best well case is 13 percent using stripper pricing forecast and 32 percent using stripper gas price forecasts.

Our payout on the best well case was five years for stripper pricing and 2.2 years for the tight gas pricing case.

Q. Plus payout would not be achieved on the average well case, is that correct?

A. That's correct.

Q. In your opinion would further development occur in this particular area without pricing incentives?

A. In my opinion it would not.

Q. Do you believe the authorization of the tight gas pricing that you've requested is in the best interest of the production in this area, the prevention of waste, and

the protection of correlative rights?

A. Yes.

Q. Were Exhibits Thirteen -- excuse me, yes, Thirteen through Nineteen prepared by you or under your direction?

A. Yes, they were, Exhibits through Twenty.

Q. Through Twenty, excuse me.

MR. BATEMAN: I have no further direct.

MR. STAMETS: The exhibits will be admitted.

Are there questions of the witness? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Tracy, for the record there are three wells that you've done back -- I'm sorry, back pressure tests and two of them were completed with limited entry and one was completed in a conventional completion.

Could you explain what the difference is between those types of completion and why they are done?

A. Well, we've tried several different completion techniques in the area and with inconclusive results.

The limited entry technique would have

fewer perforations in the casing spread further apart with the expectation that a fracture stimulation would be better controlled that way, if you'd get fracture directed to the zones where you want it, with some more control, and the perforations would then be communicated by means of the vertical fracture between the large spaced perforations.

Conventional technique would be to perforate just the areas of high porosity. In all cases the wells have been fracture stimulated and just fracturing, hoping that the fracture fluids and sand would be distributed through those intervals which we have perforated either way.

As I said, we have inconclusive results on which way is working the best for us at this time, mainly because our wells have been completed and just had an IP test run, the 3-hour or initial potential test, and we don't have any production history to compare the long term effects of the different completion techniques.

Q. Did you do any radioactive tracer survey after limited entry fracs?

A. Not in this area.

Q. On Exhibit Number Thirteen A, for the Chase Rusty Federal No. 4, you've used an h factor of 51 feet by counting the porosity intervals that had more than 8 percent, is that correct?

A. 52 feet, I believe, is the number I used, that's correct.

Q. Oh, 52 feet. Yet this is a conventional completion, not a limited entry completion, and doesn't the industry -- standard industry practice in a situation like this require that your h factor used in permeability calculations be only the -- the perforated intervals?

A. No, it's my belief that industry practice is to include log calculated pay that any -- that is contributing to production. For instance, the perforations at the top of this well, there's 4 feet perforated from 1758 to 1762, where on the density curve it appears that there's a sand there of about 11 feet in thickness of which only 4 feet of that was included in the perforations.

Now it's my opinion that there is vertical permeability in that 11 foot sand and therefor the gas at the top of the sand is also being produced in the wellbore through those 4 feet.

Q. So what we'll have there, then, is gas from the sandstone layers 6 feet above the top perforation flowing vertically down through the perforations?

A. That's right.

MR. STAMETS: While we're right there, why not perforate the entire section?

A. Well, if you feel like, as the operator apparently did, that the 4 feet of perforations on that interval were sufficient to drain the 11 feet of sand, it was a way of saving money on these wells that are already marginal.

Q. On the log that is part of that exhibit, it seems as if the -- let's see if I'm correct here. The 10 percent porosity line is the darker line -- well, let me identify it for you. That's 10 percent.

A. Right.

Q. It seems as if the perforations are more on the next line, is that 12 percent porosity? Those seem to correlate more with the perforations than the 10 percent or 8 percent porosity line does.

A. That's probably right. The conventional technique is to perf just the highest porosity, but that doesn't preclude gas from the lower porosity zones through vertical permeability being produced into the wellbore.

MR. STAMETS: Maybe I should have asked, if this had been Dome Petroleum's well, would you have perforated that entire interval?

A. Well, we've -- as I say, the results aren't back yet on whether limited entry or conventional perforating techniques are better in the long run, and we've tried both. We've done -- done them both ways.

MR. STAMETS: It would be fair to say, though, that you're convinced that that entire 11 foot section is productive and you would intend to use whatever completion technique achieved maximum production therefrom.

A. Right. That's correct.

Q. Okay, on the Dome Navajo 20-22-7 No. 1, a question comes to my mind about whether or not or how you determined that there was vertical flow from beneath the bridge plug into the upper portion of the well. How was that determined?

A. Okay. As far as current communication from the lower zone to the upper zone, that is strictly my opinion based on the prior history of the well.

The well is completed in two stages with perforations below 1525 in the first stage. They perforated, acidized, and fracture stimulated in that lower zone. Then the upperforations were made in the casing, and the well was acidized and a sand problem started where it was felt that sand was coming in from the perforations at about 1530.

So a cement retainer was set at 1525 and they pumped into the cement retainer and got pressure communication to the casing annulus immediately upon pumping.

To me that is -- that is the reason that I think that there's likely communication there. After

pumping into the cement retainer and seeing communication through the upper perfs, all the upper perfs were squeezed and reperforated and then a fracture stimulation was done on the well and the well IP tested; initial potential test was made, and it's my opinion that when they fracture stimulated the upper perforations they re-established communication to the lowermost zones.

Q. Now how do you determine that?

A. Only because of the communication that existed prior to squeezing those perfs and the high pressures involved in the fracture stimulation and the nature of vertical fracturing in these reservoirs. It's not a proven fact. It is, you know, an opinion.

Q. Well, there's no evidence on -- I'll hand you a copy of the daily drilling report for that well. Can you show me anywhere on there where it might indicate there was communication at that last fracture in the upper perfs?

A. Well, no, it's just my opinion by the nature of the high pressure, hydraulic fracture stimulation, that communication was re-established. The production from the lower zone is very similar to the production from the upper zone and no actual tracers or injection surveys were done to scientifically pin down that. There's nothing on

here that definitely, you know, it is a fact you can point at and say that's communication.

But nonetheless, even if you just include the area in the upper part of the well above the bridge plug, the average permeability is still less than a tenth millidarcy criteria.

Q. You have previously testified originally in this case that you would consider as productive those portions of the Chacra formation that had porosity of 10 percent or greater.

A. That was the testimony given by our geologist at the hearing, Michael Fuchs. He was testifying as to how we picked the limits of our application area, and how we go about picking well locations.

If a well had on his contour map showed zero feet of greater than 10 percent porosity we wouldn't drill it. That doesn't mean that a well with only 8 percent porosity wouldn't have a gas production rate, and in our opinion it wouldn't be a commercial well if it didn't have any porosity greater than 10 percent.

Q. How was the cumulative gas produced during these tests measured, did you start measuring immediately after flow back after fracture?

A. Well, no, these tests were done at a

later date after the fracture stimulation was done, the wells were shut-in for months and we came back to do the special testing required to get a long enough build-up for the Horner plot.

Gas flow rates were measured hourly, I believe. It's on the field data sheet there, the gas rates recorded at different times.

Q. So what you did was you just got the cumulative gas off that open flow?

A. Well, it's off of an 8-hour drawdown prior to the 8-day build-up.

The wells were certainly stabilized at reservoir pressure after being shut-in several months before we ran these special tests.

Q. Turning to your economics, Exhibit Number Sixteen, why did you use an NGPA price of Section 102 rather than Section 103 for the Rusty Chacra?

A. The Rusty Chacra area did not be in production until 1978 and from most of the area there was no production within 2-1/2 miles. Most of it will qualify as 102. There are a few areas that I'm aware of where it was old Gallup gas production that might be 103 rather than 102.

And that only comes in effect on the

best well case the very first year, because that is the only case where gas production rates were above the stripper rate of 60 Mcf a day.

Q. What is the distribution of the royalty burden that give you a working interest -- I'm sorry, that give you a 16.6 royalty for the average? It would be the combination of the --

A. Well --

Q. -- Navajo, Federal, and State royalties?

A. Well, actually our Navajo leases are burdened with 16-2/3rds percent royalty rate. Federal leases have less, but there are also overrides involved in a lot of the leases we've picked up from other companies in the area.

So we, rather than try to compute all the royalty rates in the area and come up with a real average, we used what the majority of our leases are in the area, or Navajo leases.

Q. So that was just more of an assumption rather than an actual calculated --

A. That's correct.

Q. On average Rusty Chacra well you show a Section 108, or stripper price that gives you only a four year productive life for the well with a cumulative of less than 30 MMCF.

A. That's correct. The economic forecast shown here stops when the economic limit is reached, when operating costs exceed revenue.

Q. The economically recoverable reserves, then, in your best well case as shown in Exhibit Twenty, are 162.3 and then 115.3 MMCF.

A. No, that's the --

Q. For Section 108, and 118 MMCF for Section 107?

A. That's correct.

Q. Do you have calculated -- or a listing of calculated recoverable reserves for the wells that you have now drilled in the Chacra, Rusty Chacra Field?

A. No, I don't. And really, before we can accurately evaluate that, we have to get all wells on production and see if they behave similarly to these older wells in the field, and forecast declines.

Volumetric in these tight, low pressure reservoirs are -- are inaccurate because really the controlling factor is when you reach the economic limit, not whether you recover all the gas in place.

Q Do you think your -- the Dome wells in the Rusty Chacra Field will have a slower decline and better production rate than the original Chase wells because of the

improved completion techniques?

A. Well, that remains to be seen. We're hopeful that they'll be similar to the best Chase well producing out there now, which is our best well case.

Whether they exceed that or not, I really don't feel confident that they will.

Q. In computing your cash flow at a 15 percent discount rate, is that the cost of the equity involved in investments for these wells?

A. Well, the costs of -- cost of capital varies from company to company and the source of your funding.

We just showed 15 percent as a discount rate and 20 percent as a second one, rather than what our actual cost of capital is.

Q. Well, based on a project like this, would Dome finance this with equity or with debt, which would change, of course, the -- are you qualified to speak to this?

A. I really can't answer that question.

MR. STAMETS: Somebody is going to pay for it with debt some place.

Q. What's been the rate of return that Dome has supplied its equity owners this last year, or are you qualified to speak to that?

A. I'm really not qualified to speak to that, either. Sorry.

MR. CHAVEZ: I don't have any further questions.

MR. STAMETS: Any other questions of this witness? He may be excused.

Anything further in this case?

MR. BATEMAN: Nothing further.

MR. STAMETS: The case will be taken under advisement.

(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 CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7306, heard by me on 10-26, 19 81.

Richard L. Stamets, Examiner
Oil Conservation Division

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Effect of Rock Stress on Gas Production From Low-Permeability Reservoirs

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Introduction

The decline in gas reserves has stimulated widespread interest in gas-bearing formations previously considered to be uneconomic because of extremely low permeability. Routine core analyses have indicated permeabilities in many such reservoirs on the order of 0.1 md and lower. Wells in such reservoirs have been proposed as candidates for nuclear or high-explosives stimulation to increase production rates.

In investigating the flow behavior of wells in tight gas reservoirs, it has been observed that measured flow rates are sometimes much lower than predicted by transient gas flow equations based on Darcy's law. Several plausible explanations for this discrepancy have been offered. (1) Errors may be caused by deviation from the usual simplifying assumptions such as reservoir homogeneity, open-hole completions, and single-phase flow. (2) Non-Darcy effects due to high gas velocity near the wellbore may restrict flow. (3) Liquid from retrograde condensation or formation of gas hydrates can reduce permeability; however, the ranges of the temperature, pressure, and gas composition necessary for this to occur are usually not encountered in low-permeability gas reservoirs.

This paper discusses a mechanism that may have a significant effect on production from tight gas reservoirs — reduction of permeability due to rock stress. Lowering of pore pressure as gas is produced increases the confining stresses on the reservoir rock, causing it to compact. The compaction causes reduction of the effective pore diameters, resulting in a decreased permeability. This effect has been studied by several authors.[1-5] These studies covered both clean and shaly sandstones. Confining pressures were applied hydrostatically and with different pressure applied to the sides of the core than to the ends. Only one set of data[5] was reported for a core of less than 0.1 md permeability. The effect of stress on this core with very low permeability was much greater than the effect on the others. A possible explanation for this is that very tight cores have smaller pore radii. Increasing the compressive stress applied to pores of small radius could decrease their flow capacity proportionately more than that of larger pores.

This study was conducted (1) to confirm the conclusions of previous work,[1-5] and to demonstrate experimentally that permeability reduction is proportionately greater in low-permeability than in high-permeability cores; (2) to incorporate the stress effect into a methematical model for reservoir gas flow; and (3) to use this model to check the extent of production decrease that might be expected because of permeability's sensitivity to stress.

Laboratory Measurements of Stress Effect on Permeability

A schematic diagram of the experimental apparatus is shown in Fig. 1. Basically it consisted of a cell for applying pressure to cylindrical cores, a nitrogen source for permeability measurement, pressure gauges, and a flow meter. The core samples were 2 in. long and 2 in. in diameter. Sample preparation consisted of oven drying at 110°C, then coating the

The effect of stress on permeability has been incorporated into a mathematical model for gas flow based on a theoretical analysis of the stress state around a wellbore. Example calculations show that permeability reduction due to stress can significantly affect the production characteristics of wells in tight gas reservoirs.

cylindrical surface with a thin layer of epoxy resin.

The sealed cores were inserted in a 2-in.-ID rubber sleeve having a $^{1}/_{16}$-in. wall. The encased sample was then placed in the stainless steel cell as shown in Fig. 1, and the annulus was filled with hydraulic fluid to a pressure of 500 psig. This was chosen as the minimum confining pressure to insure that there would be no leakage past the rubber sleeve.

As can be seen from Fig. 1, the cores were hydrostatically loaded except for small areas at the ends where the gas lines were connected. The confining pressures generated normal stresses both transverse and parallel to the direction of fluid flow within the core. These normal stresses were equal in all directions.

Permeability measurements were made at several levels of confining pressure for each core by flowing nitrogen through it. The nitrogen was introduced at a constant pressure of 150 psig. The permeability was calculated using the steady-state gas flow equation.

Figs. 2 through 4 illustrate some general observations made during the course of the study. Each plot shows F, the ratio of permeability at a given confining pressure to the permeability at a confining pressure of 500 psig, as a function of confining pressure. The 500-psig initial confining pressure was the initial condition for each series of permeability measurements.

Fig. 2 illustrates the greater degree of permeability reduction with low-permeability cores than with high-permeability cores. The permeability of each core at 500 psig confining pressure, k_{ai}, is shown on the figure. Core A is Chanute sandstone, Core B is San Andres carbonate, Cores C and D are Springer sandstone, and Core E is a Frio sandstone. All the cores appeared uniform in texture and free of shale streaks and hairline fractures when examined visually. In cores with initial permeability less than 1 md, the permeability is significantly reduced at high net confining pressure.

The presence of shale streaks and hairline fractures appeared to increase drastically the permeability reduction due to stress, as shown on Fig. 3. Core C represents the uniform Springer sandstone shown on Fig. 1, whereas Core F is a Springer sandstone laminated with shale streaks and exhibiting hairline fractures.

The effect of tiny hairline fractures and shale streaks is further illustrated on Fig. 4. Cores G and H are both from the same San Andres formation well. Both showed the presence of hairline fractures. However, Core H also had shale streaks. Core H exhibited somewhat greater permeability reduction, although it has a higher initial permeability. It was concluded that although the general effect shown in Fig. 2 is true as a rule, the presence of factors disturbing the uniformity of the core can have overriding effects.

Discussion of the experimental work would be incomplete without mention of hysteresis effects. Fig. 5 shows this effect for a Morrow sandstone core. On it are shown the permeability under certain stress levels and the permeability recovery after the confining pressure was quickly lowered to 500 psig. Tests were also performed in which permeability reduction curves were measured, the sample was allowed to remain under no stress for 43 days, and then it was restressed under identical conditions. Although some samples showed almost no hysteresis effect when stressed to 20,000 psi, most of them, like the Devonian dolomite shown on Fig. 6, had a pronounced effect. The hysteresis effect was not observed to be strongly related to the permeability but was dependent on the previous stress history of the sample. That is, when hysteresis occurs, its magnitude is dependent upon the maximum stress to which the rock has been subjected. This effect is also shown in the short-term test of Fig. 5.

Figs. 2 through 4 show that when the stress effect is significant most of the loss of permeability occurs by the time the confining stress level reaches about 4,000 psi. This is in line with the observations of Fatt and Davis.[1]

It can be seen that the permeability of a rock may

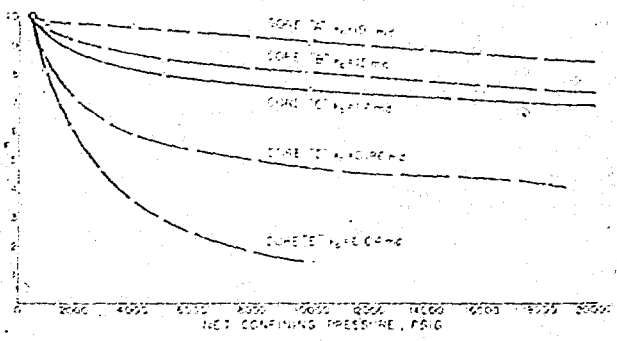


Fig. 2—Permeability ratio vs net confining pressure.

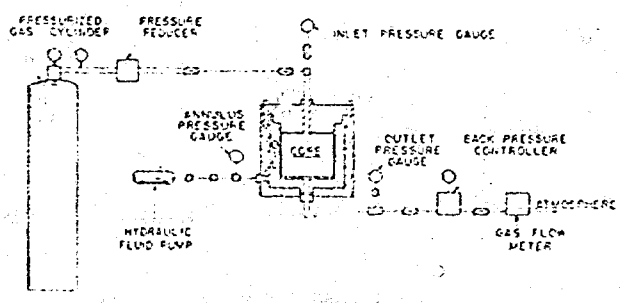


Fig. 1—Experimental test apparatus.

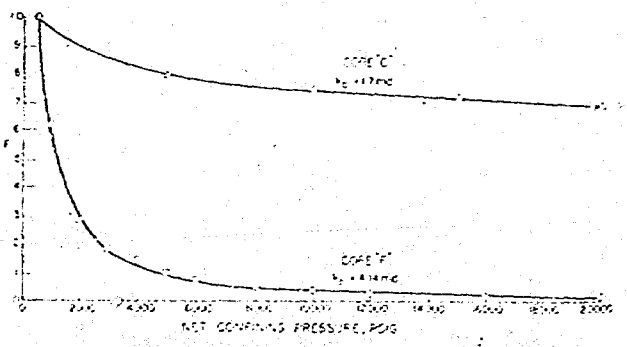


Fig. 3—Permeability ratio vs net confining pressure.

depend on confining pressure in a complex manner. In the experimental measurements, the confining pressure was applied uniformly in all directions. Since the pore pressure during the flow tests was very low, the confining pressure is, in effect, the rock stress. In relating the experimental results to reservoir calculations it is necessary to know the conditions that affect rock stress in the reservoir. In particular, stress effects near the wellbore are important.

Rock Stresses near a Wellbore

The state of stress around a wellbore in a porous medium has been treated by Lubinski[6] and more recently by Deily and Owens[7] as well as by others. The stress equations for this study were adapted from Lubinski. He defined macrostress, σ, as the average intensity of force per unit of total area, and microstress, σ', as the average intensity of force per unit area of the interpore material. A third type of stress represents the component of the macrostress that is primarily responsible for permeability and porosity changes; it will be called effective macrostress, σ'''.

First, consider macrostresses. Strain in a porous medium subjected to formation stresses (macrostresses) and pore pressure is, according to Lubinski,

$$\epsilon_r = \frac{1}{E}[\sigma_r - \nu(\sigma_\theta + \sigma_z)] + \frac{1-2\nu}{E}(1-\beta-\phi)p, \quad \ldots\ldots\ldots\ldots\ldots\ldots (1)$$

$$\epsilon_\theta = \frac{1}{E}[\sigma_\theta - \nu(\sigma_r + \sigma_z)] + \frac{1-2\nu}{E}(1-\beta-\phi)p, \quad \ldots\ldots\ldots\ldots\ldots\ldots (2)$$

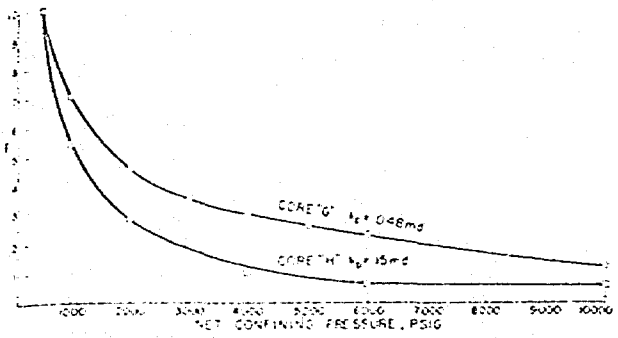


Fig. 4—Permeability ratio vs net confining pressure.

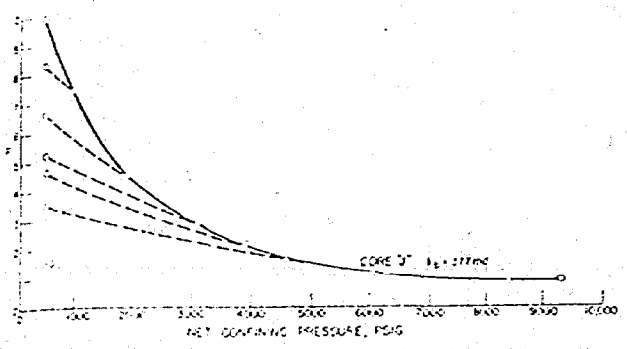


Fig. 5—Permeability recovery 1 hour after stress removal.

$$\epsilon_z = \frac{1}{E}[\sigma_z - \nu(\sigma_r + \sigma_\theta)] + \frac{1-2\nu}{E}(1-\beta-\phi)p, \quad \ldots\ldots\ldots\ldots\ldots\ldots (3)$$

where

$$\beta = \frac{(1-2\nu_i)/E_i}{(1-2\nu)/E}.$$

The shear strain is given by

$$\gamma_{r\theta} = \frac{1}{G}\tau_{r\theta} \quad \ldots\ldots\ldots\ldots\ldots\ldots (4)$$

$$\gamma_{\theta z} = \frac{1}{G}\tau_{\theta z} \quad \ldots\ldots\ldots\ldots\ldots\ldots (5)$$

$$\gamma_{rz} = \frac{1}{G}\tau_{rz} \quad \ldots\ldots\ldots\ldots\ldots\ldots (6)$$

These relationships are similar to those used in thermal stress studies for which impermeable bodies are subjected to surface forces and temperature. Because of this similarity, equations from thermal stress studies can be modified and used to determine stresses in porous rock.

Using the thermal stress equations, we find that the triaxial macrostresses near a wellbore are described by

$$\sigma_r = (1-\beta)\frac{1-2\nu}{1-\nu}\frac{1}{r^2}\left[\frac{r^2 - r_{sc}^2}{r_d^2 - r_{sc}^2}\left(\int_{r_{sc}}^{r_d} prdr - \int_{r_w}^{r} prdr\right)\right.$$
$$- \frac{r_{sc}^2 r_d^2 (p_{sc} - p_d)}{r_d^2 - r_{sc}^2}\frac{1}{r^2}$$
$$+ \frac{r_{sc}^2 p_{sc} - r_d^2 p_d}{r_d^2 - r_{sc}^2} + \phi p$$
$$\left. + \frac{r_d^2}{r_d^2 - r_{sc}^2}\left(\frac{r_{sc}^2}{r^2} - 1\right)(\sigma_f - p_d)\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots (7)$$

$$\sigma_\theta = (1-\beta)\frac{1-2\nu}{1-\nu}\frac{1}{r^2}\left[\frac{r^2 + r_{sc}^2}{r_d^2 - r_{sc}^2}\left(\int_{r_{sc}}^{r_d} prdr + \int_{r_w}^{r} prdr - pr^2\right)\right.$$
$$+ \frac{r_{sc}^2 r_d^2 (p_{sc} - p_d)}{r_d^2 - r_{sc}^2}\frac{1}{r^2}$$
$$+ \frac{r_{sc}^2 p_{sc} - r_d^2 p_d}{r_d^2 - r_{sc}^2} + \phi p$$
$$\left. - \frac{r_d^2}{r_d^2 - r_{sc}^2}\left(\frac{r_{sc}^2}{r^2} + 1\right)(\sigma_f - p_d)\right], \quad \ldots\ldots\ldots\ldots\ldots\ldots (8)$$

$$\sigma_z = (1-\beta)\frac{1-2\nu}{1-\nu}\left(\frac{2}{r_d^2 - r_{sc}^2}\int_{r_w}^{r_d} prdr - p\right)$$
$$+ \phi p - \sigma_o \quad \ldots\ldots\ldots\ldots\ldots\ldots (9)$$

The last terms in Eqs. 7 and 8 account for horizontal formation loading through impermeable boundaries, whereas the last term in Eq. 9 accounts

for overburden loading through impermeable boundaries; these terms were superimposed on Lubinski's equations. Lubinski's equations do not include these terms because he considered stresses and flow through an open cylindrical rock capped with impermeable horizontal boundaries. For example, without the last term in Eq. 7, σ_r at $r = r_d$ is $-(1-\phi)p_d$. With the last term included in Eq. 7, σ_r at $r = r_d$ is $(-\sigma_l + \phi p_d)$.

Because of symmetry, the shear stresses are zero. Note that the three stress components depend on the pressure distribution, which is to be determined. Assuming that the macrostresses can be determined, let us now consider how microstesses and effective stresses are determined from them.

Microstresses are related to the macrostresses by the following simple relationships:

$$\sigma'_r = \frac{\sigma_r}{1-\phi} \quad \ldots\ldots\ldots \quad (10)$$

$$\sigma'_\theta = \frac{\sigma_\theta}{1-\phi} \quad \ldots\ldots\ldots \quad (11)$$

$$\sigma'_z = \frac{\sigma_z}{1-\phi} \quad \ldots\ldots\ldots \quad (12)$$

Effective stresses are determined as follows (see Fig. 7). For the moment, consider only σ'_r. It can be divided into two components so that

$$\sigma'_r = p + \sigma''_r \quad \ldots\ldots\ldots \quad (13)$$

But substituting for the microstress, σ'_r, gives

$$\sigma''_r = \frac{\sigma_r}{1-\phi} - p \quad \ldots\ldots\ldots \quad (14)$$

We can now look at the original microstress in the r direction as the sum of two microstresses having magnitudes of p and σ''_r. Similarly in the other two directions, (θ, z),

$$\sigma''_\theta = \frac{\sigma_\theta}{1-\phi} - p \quad \ldots\ldots\ldots \quad (15)$$

and

$$\sigma''_z = \frac{\sigma_z}{1-\phi} - p \quad \ldots\ldots\ldots \quad (16)$$

The microstress state on a cubical element in a reservoir can be divided into two microstress states; one in which the matrix in the cube is completely surrounded, inside and out, by pressure equal to the local pore pressure and another in which the microstresses are σ''_r, σ''_θ, and σ''_z, with no pore pressure. It is reasonable to assume that rock permeability and porosity do not vary appreciably by pressure completely surrounding the rock cube. The changes in permeability and porosity, then, vary mainly because of σ''_r, σ''_θ, σ''_z. The corresponding macrostresses, called effective stresses, are

$$\sigma'''_r = (1-\phi)\,\sigma''_r = \sigma_r - (1-\phi)p \quad \ldots \quad (17)$$

$$\sigma'''_\theta = (1-\phi)\,\sigma''_\theta = \sigma_\theta - (1-\phi)p \quad \ldots \quad (18)$$

$$\sigma'''_z = (1-\phi)\,\sigma''_z = \sigma_z - (1-\phi)p \quad \ldots \quad (19)$$

Effective stresses are the ones that were produced in the laboratory experiments to obtain the data discussed in the previous section. During the laboratory tests, the effective stresses (or confining pressure) were equal in all transverse directions. Actually, the principal normal stresses (σ'''_θ and σ'''_z) are unequal near the wellbore. Therefore, in relating the rock permeabilities produced in the laboratory to permeabilities in the reservoir, the following assumption was made:

$$\sigma_e \simeq \tfrac{1}{2}\,(\sigma'''_z + \sigma'''_\theta) \quad \ldots\ldots\ldots \quad (20)$$

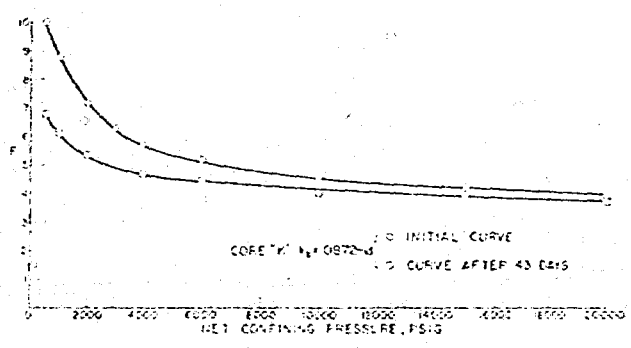


Fig. 6—Permeability recovery 43 days after stress removal.

Mathematical Model for Reservoir Gas Flow

Reduction of permeability due to intergranular macrostress (effective stress) was incorporated into a numerical model for gas flow to a well in a circular reservoir, based on the isothermal gas flow equation

$$\frac{1}{r}\frac{\partial}{\partial r}\left(-r\,\frac{p}{z}\,\frac{k}{\mu}\,\frac{\partial p}{\partial r}\right) = -\phi\,\frac{\partial}{\partial t}\left(\frac{p}{z}\right) \quad \ldots\ldots\ldots \quad (21)$$

Solution of this equation was obtained using a procedure similar to that of Bruce *et al.*[7] Gas properties were allowed to be functions of pressure. Either rate or pressure could be specified as a boundary condition at the well. The drainage radius was considered to be a no-flow boundary. The model was verified by comparing test calculations with published solutions and with the semisteady-state solution.

Permeability reduction due to stress was included by calculating the principal effective stresses for each time step. Since the net flow is radial, it was assumed that permeability reduction due to stress in the direction of flow would be small near the wellbore compared with that due to the vertical and tangential stresses. Thus the permeability reduction was assumed to be primarily a function of σ'''_θ and σ'''_z.

The vertical and tangential effective stresses were calculated by Eqs. 8, 9, 18, and 19. The effective stress for permeability reduction was calculated by Eq. 20. This stress, σ_e, is the net confining pressure on Figs. 2 through 4. In the model, the permeability was determined by the laboratory tests relating σ_e to permeability.

It can be seen that permeability depends on effective stress. Effective stress is a function of pore pressure, which in turn is a function of permeability. In the model we treated this relationship by iterating during each time step.

Similar models having permeability that varies with ore pressure were presented by Eilerts *et al.*,[5] and Raghaven *et al.*[10] However, the permeability was not considered to be a function of stress. We believe that using the permeability reduction on stress, which is a function of pore pressure, is theoretically more sound.

Prediction of Reservoir Performance

The numerical model was used to calculate expected flow rates for the example reservoir conditions shown in Table 1. Ideal gas properties were used to emphasize the effect of permeability variation with stress and to allow easy comparison with analytical solutions. The experimental permeability reduction curves for a Morrow sandstone and San Andres carbonate were used in the calculations. These curves are shown in Fig. 8.

Figs. 9 and 10 show the calculated flow rate as a function of time when the two formations are produced at a constant bottom-hole pressure of 2,000 psia. On each figure, the upper curve is for a constant permeability of 0.1 md — that is, there is no stress effect. The middle curve is for the permeability that is obtained when the porous medium is subjected to the stresses calculated for the reservoir at its initial pore pressure — that is, before production starts. The resultant permeability is shown on the two curves and is different for each because of different rock characteristics shown by Fig. 8. For these two curves the permeability was not allowed to change from its initial value during gas production. One might look at the upper curve as representing the flow rate calculated using permeability obtained from a conventional core test, and the middle curve as that calculated using permeability obtained from a transient pressure test early in the life of the reservoir. The bottom curve on Figs. 9 and 10 shows the flow rate when the permeability is variable with stress. The contrast between the middle and bottom curves shows the effect of the additional permeability reduction near the wellbore because of the pressure drawdown.

Fig. 11 shows the flow rate as a function of bottom-hole pressure for the Morrow sandstone at 0.2 and 2.2 years after start of production, for the cases of stress-variable permeability and constant in-situ permeability. In addition to having a lower flow rate, the

TABLE 1—RESERVOIR AND GAS PROPERTIES

Wellbore radius, ft	0.25
Drainage radius, ft	2,980
Net pay thickness, ft	100
Hydrocarbon porosity	0.04
Initial permeability, md	0.1
Temperature, °F	340
Initial pressure, psia	7,000
Overburden stress,* psi	10,000
Formation stress,** psi	8,000
Poisson's ratio	0.2
Rock compressibility ratio	0.25
Gas compressibility factor	1.0
Gas viscosity, cp	0.015

*Corresponds to 10,000-ft well depth.
**Formation stress was arbitrarily chosen as 80 percent of the overburden.

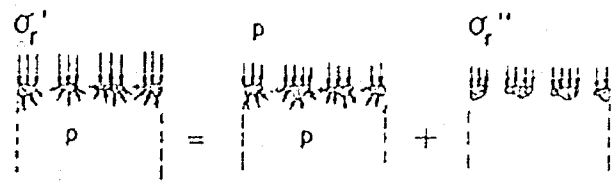


Fig. 7—Distribution of microstress.

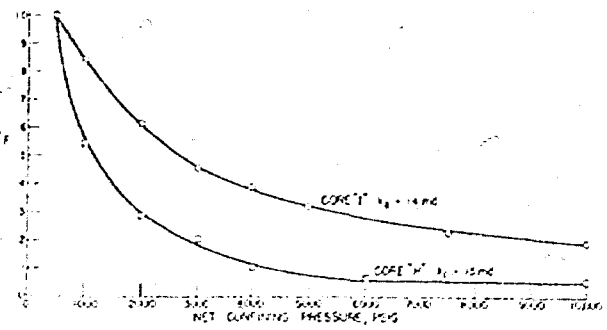


Fig. 8—Permeability ratio vs net confining pressure.

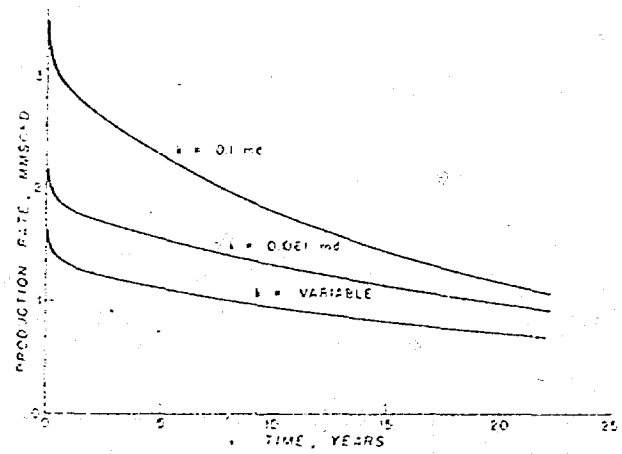


Fig. 9—Production rate vs time at constant wellbore pressure, Morrow sandstone. p_w = 2,000 psia.

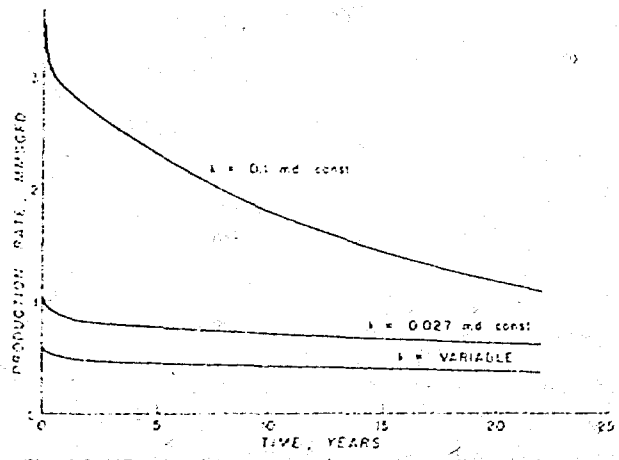


Fig. 10—Production rate vs time at constant wellbore pressure, San Andres carbonate. p_w = 2,000 psia.

stress-variable curves are somewhat flatter at low bottom-hole pressures. This suggests that in rocks with permeability sensitive to stress, increasing the pressure drawdown may not give the expected production rate increase.

Fig. 12 shows bottom-hole pressure as a function of time at a constant production rate of 1 MMscf/D for the Morrow sandstone. The permeability cases are the same as on Fig. 9. Fig. 12 is further confirmation of the possible significant effects on production from tight gas reservoirs when permeability is sensitive to rock stress.

Conclusions

1. Very tight rocks are affected by stress more than permeable rocks. This confirms the observation of McLatchie *et al.*[2]

2. The permeability of a rock depends complexly on confining pressure (stress). Rock heterogeneities, such as fractures and shale streaks, accentuate the permeability reduction due to stress.

3. The effect of stress on permeability has been incorported into a mathematical model for gas flow, based on a theoretical analysis of the stress state around a wellbore. Example calculations show that permeability reduction due to stress can significantly affect the production characteristics of wells in tight gas reservoirs.

Nomenclature

E = modulus of elasticity of bulk, psi
E_i = modulus of elasticity of rock matrix, psi
F = ratio of permeability at a given confining pressure to that at a confining pressure of 500 psig
G = shear modulus, psi
k = permeability, md
k_i = permeability of a core at 500 psig confining pressure, md
p = pore pressure, psia
p_d = drainage boundary pressure, psia
p_w = wellbore pressure, psia
r = radial distance from center of well, ft
r_d = drainage boundary radius, ft
r_w = wellbore radius, ft
t = time
z = gas compressibility factor
β = ratio of compressibility of rock matrix to that of the bulk
γ = shear strain
ϵ = normal strain
μ = viscosity, cp
ν = Poisson's ratio of bulk sample
ν_i = Poisson's ratio of rock matrix
σ = macrostress, psi
σ_c = confining pressure on core, psi
σ_f = stress due to horizontal loading, psi
σ_o = stress due to overburden, psi
σ' = microstress, psi
σ'' = effective microstress, psi
σ''' = effective macrostress, psi
τ = shear stress, psi
ϕ = porosity

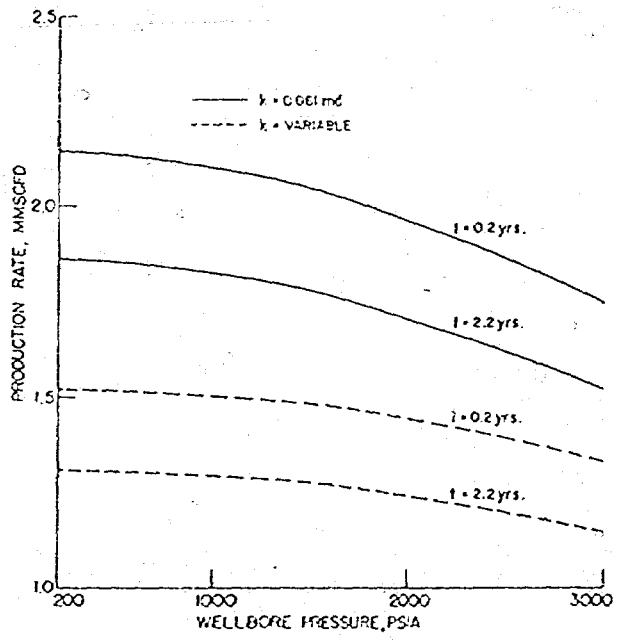


Fig. 11—Production rate vs wellbore pressure, Morrow sandstone.

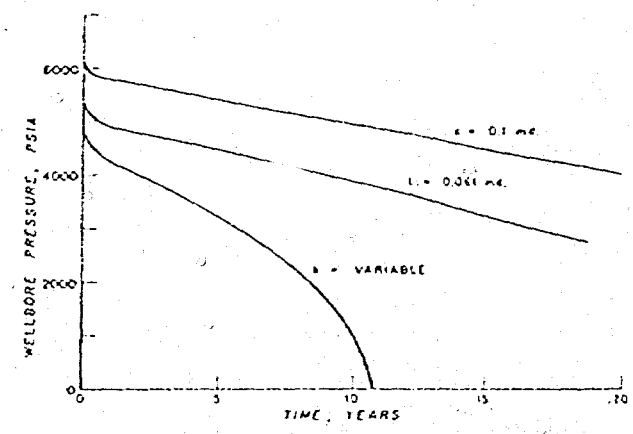


Fig. 12—Wellbore pressure vs time at constant production rate of 1 MMscf/D, Morrow sandstone.

Subscripts

r = radial

z = vertical

θ = tangential

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7. Deily, F. H. and Owens, F. C.: "Stress Around a Wellbore", paper SPE 2557 presented at SPE 44th Annual Fall Meeting, Denver, Colo., Sept. 28-Oct. 1, 1969.

8. Bruce, G. H., Peaceman, D. W., Rachford, H. H., Jr., and Rice, J. D.: "Calculations of Unsteady-State Gas Flow Through Porous Media", *Trans.*, AIME (1953) 198, 79-92.

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10. Raghaven, R., Scorer, J. T. D. and Miller, F. G.: "An Investigation by Numerical Methods of the Effect of Pressure Dependent Rock and Fluid Properties on Well Flow Tests", paper SPE 2617 presented at SPE 44th Annual Fall Meeting, Denver, Colo., Sept. 28-Oct. 1, 1969. JPT

Original manuscript received in Society of Petroleum Engineers office July 31, 1970. Revised manuscript received July 1, 1971. Paper (SPE 3001) was presented at SPE 45th Annual Fall Meeting, held in Houston, Oct. 4-7, 1970, and at SPE Annual Eastern Regional Meeting, held in Pittsburgh, Nov. 5-6, 1970.

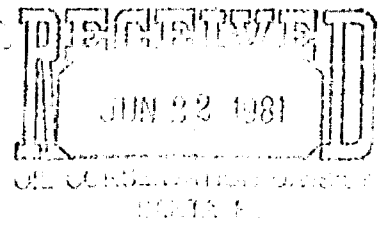
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This paper will be printed in *Transactions* volume 251, which will cover 1971.

BENSON
MINERAL
GROUP, INC.

June 18, 1981

Case 7306



State of New Mexico
Energy and Minerals Department
Oil Conservation Division
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: Tight Gas Designation
for the Chacra Formation
Sandoval County, New Mexico
filed by Dome Petroleum
Corporation

Gentlemen:

Benson Mineral Group, Inc. has received a copy of a tight sand gas formation application from Dome Petroleum Corporation for the Chacra formation in Sandoval County, New Mexico.

We feel that all of their exhibits and their information meet the tight sand qualifications and therefore are in agreement that the Chacra should be designated under NGPA Section 107 for tight sand designation at the hearing on July 2, 1981.

Sincerely yours,

BENSON MINERAL GROUP, INC.

Bruce D. Benson
President

BDB/mmm

cc: Kevin Tracy
Sr. Reservoir Engineer
Dome Petroleum Corporation

1726 Champa Street Suite 600 Denver, CO 80202 (303) 893-0883

CHACE DEVELOPMENT CO., INC.
313 Washington S.E.
Albuquerque, New Mexico 87108
(505) 266-5562

June 18, 1981

RECEIVED
JUN 22 1981
OIL CONSERVATION
SANTA FE

Case 7300

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Sirs:

This letter will inform you that we are interested in endorsing and supporting Dome Petroleum to qualify the Chacra area and the Rusty Chacra formation as a tight gas formation in Sandoval County, New Mexico.

Thank you for your consideration.

Sincerely,

Royce McCary

RM/lv

cc: Dome Petroleum Corp.

RECEIVED
JUN 24 1981
OIL CONSERVATION DIVISION
SANTA FE

TREND EXPLORATION LIMITED
777 Grant Street - Suite 600
Denver, Colorado 80203 USA
(303) 861-2472
Telex 45670

June 19, 1981

Case 7300

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P. O. Box 2088
Santa Fe, New Mexico 87501

RE: Tight Gas Designation
For the Chacra Formation
Sandoval County, New Mexico

Dear Sirs:

Trend Exploration Limited as a working interest owner with Dome Petroleum Corp. in certain wells completed in the Chacra Formation in Sandoval County, New Mexico, hereby expresses its support for Dome's proposal to qualify the Chacra Formation as a tight formation at a hearing before the Oil Conservation Division of the Energy and Minerals Department of the State of New Mexico on July 2, 1981.

We believe the engineering data to be presented by Dome Petroleum together with the application to the Oil Conservation Division will adequately meet the tight formation criteria.

Yours truly,

D. W. Martin

David W. Martin
Vice President Engineering

DWM/dg

cc: K. F. Tracy
Dome Petroleum Corp.
Dnver, Co.

314 SECURITY NATIONAL BANK BUILDING

CHARLES B. READ
PRESIDENT

NORMAN L. STEVENS, JR.
VICE-PRESIDENT

Read & Stevens, Inc.
Oil Producers
P. O. Box 1518
Roswell, New Mexico 88201

PHONE 505 622-3770

RECEIVED
JUN 24 1981
OIL CONSERVATION DIVISION
SANTA FE

June 22, 1981

Case 7300

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: Tight Gas Designation
for the Chacra formation
Sandoval County, New Mexico

Gentlemen:

Read & Stevens, Inc. is in full support of the application from Dome Petroleum Corporation on the aboved caption.

Yours very truly,

READ & STEVENS, INC.

Joe Wigley
Land Manager

JW:jj

JACK A. COLE
PETROLEUM GEOLOGIST
P.O. BOX 191
FARMINGTON, NEW MEXICO 87401
(505) 325-1415

RECEIVED
JUN 18 1981
OIL CONSERVATION DIVISION
SANTA FE

June 16, 1981

Case 7300

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P. O. Box 2088
Santa Fe, New Mexico 87501

Gentlemen:

This letter is to advise you that Jack A. Cole does hereby fully endorse and support the application of Dome Petroleum Corporation to qualify the Chacra formation in the Rusty Chacra area of Sandoval County, New Mexico as a tight gas sand formation under NGPA Section 107.

It is my intention to have a representative present at the hearing on this application scheduled for July 2, 1981. It is my opinion, after drilling, testing and completing several wells in this area, that the Chacra sand meets all requirements under the guidelines given in 18 CFR 271.705. Please incorporate this letter into the hearing file and read letter into the record of the hearing.

Sincerely,

Jack A. Cole

JAC:njs

cc: K. F. Tracy
Dome Petroleum Corporation
Denver, Colorado
E. N. Walsh

BUCKHORN
PETROLEUM CO.
A Subsidiary of Peoples Energy Corporation

RECEIVED
JUN 30 1981
OIL CONSERVATION DIVISION
SANTA FE

June 30, 1981

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
Post Office Box 2088
Santa Fe, New Mexico 87501

RE: Dome Petroleum Corp.
Tight Gas Designation Filing
Dated May, 1981
Chacra Formation
Sandoval County, New Mexico

Gentlemen:

Buckhorn Petroleum Co. has received a copy of Dome Petroleum Corp.'s captioned filing for the designation of the Chacra Formation as a "Tight Gas Formation" under Section 107 of the NGPA. As a working interest owner in several of the wells and undeveloped acreage affected by this filing Buckhorn has reviewed the submittal of Dome Petroleum and is in complete agreement with the assertions made by Dome in this filing. Buckhorn feels that the Chacra Formation meets the requirements under Section 107 to receive the "Tight Gas Formation" designation and that such a classification will encourage the development of substantial additional gas reserves from the Chacra Formation.

We ask that this letter be accepted by the Oil Conservation Division as Buckhorn Petroleum Co.'s support of Dome Petroleum Corp.'s captioned filing. Your timely consideration of this filing is appreciated.

Yours truly,

BUCKHORN PETROLEUM CO.

Walt Pearson
Manager of Engineering

WP/pla
cc: Mr. Dan B. Grabb
Natural Gas Pipeline Company of America
Post Office Box 283
Houston, Texas 77001

Mr. K. F. Tracy
Dome Petroleum Corp.
2900 Dome Tower, 1625 Broadway, Denver, Colorado 80202

elf aquitaine oil and gas
Division of Elf Aquitaine Inc

June 30, 1981

Re: Case Number 7300
Dome Petroleum Corporation's
Application for a Tight Gas Designation
for the Chacra Formation
Sandoval County, New Mexico

State of New Mexico
Energy and Minerals Department
Oil Conservation Division
P. O. Box 2088
Santa Fe, New Mexico 87501

Gentlemen:

This is to advise that Elf Aquitaine, Inc., an interest owner in numerous wells completed in the Chacra Formation, has received a copy of the exhibits contained in the referenced application, and after review concurs with Dome Petroleum Corporation's findings.

Sincerely

A. L. Nicolais
Production Manager

PEN/co/631

BFL

ONE MEMORIAL CITY PLAZA, SUITE 1200
800 GESSNER, HOUSTON, TEXAS 77024
(713) 827-9895 TELEX: PETRAKI, HOU 762-424

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION

November 25, 1981

Mr. R. L. Stamets
Oil Conservation Division
State of New Mexico
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: NMOCD Case No. 7300 - Application
of Dome Petroleum Corp. for
Designation of Dome Petroleum Corp.
for designation of a tight formation
Sandoval County, New Mexico

Dear Mr. Stamets:

As you requested, I have prepared the enclosed draft Order in the above matter.

If I may be of further assistance, please let me know.

Sincerely yours,

KENNETH BATEMAN

KB/bah
cc: Kevin Tracy
Senior Reservior Engineer
Dome Petroleum Corp.

Mailing Address: P.O. Box 787, Santa Fe, N.M. 87501
Street Address: 220 Otero St., Santa Fe, N.M. 87501 (505) 982-4374

L. C. White
Sumner S. Koch — *Larry C. White*
William Booker Kelly — *Forrest S. Smith*
John F. McCarthy, Jr. — *John N. Patterson*
Kenneth Bateman — *Paula Tackett*
Benjamin Phillips — *Filmore E. Rose*

Attorneys and Counselors at Law

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

January 12, 1982

Mr. Kenneth Bateman
White, Koch, Kelly & McCarthy
Attorneys at Law
Post Office Box 787
Santa Fe, New Mexico 87501

Re: CASE NO. 7300
ORDER NO. R-6874

Applicant:

Dome Petroleum Corporation

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

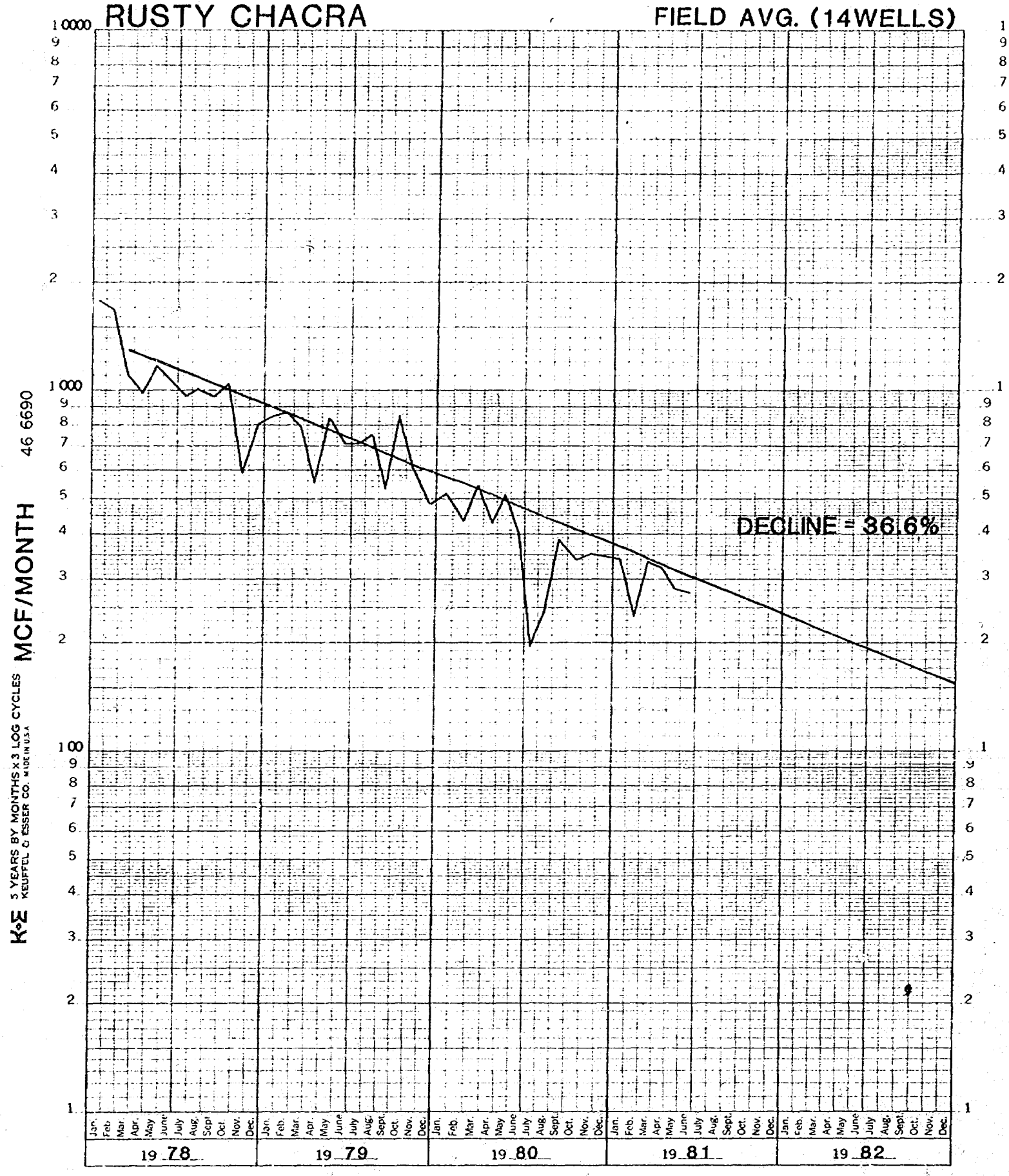
Copy of order also sent to:

Hobbs OCD x
Artesia OCD x
Aztec OCD x

Other _____

RUSTY CHACRA

FIELD AVG. (14WELLS)

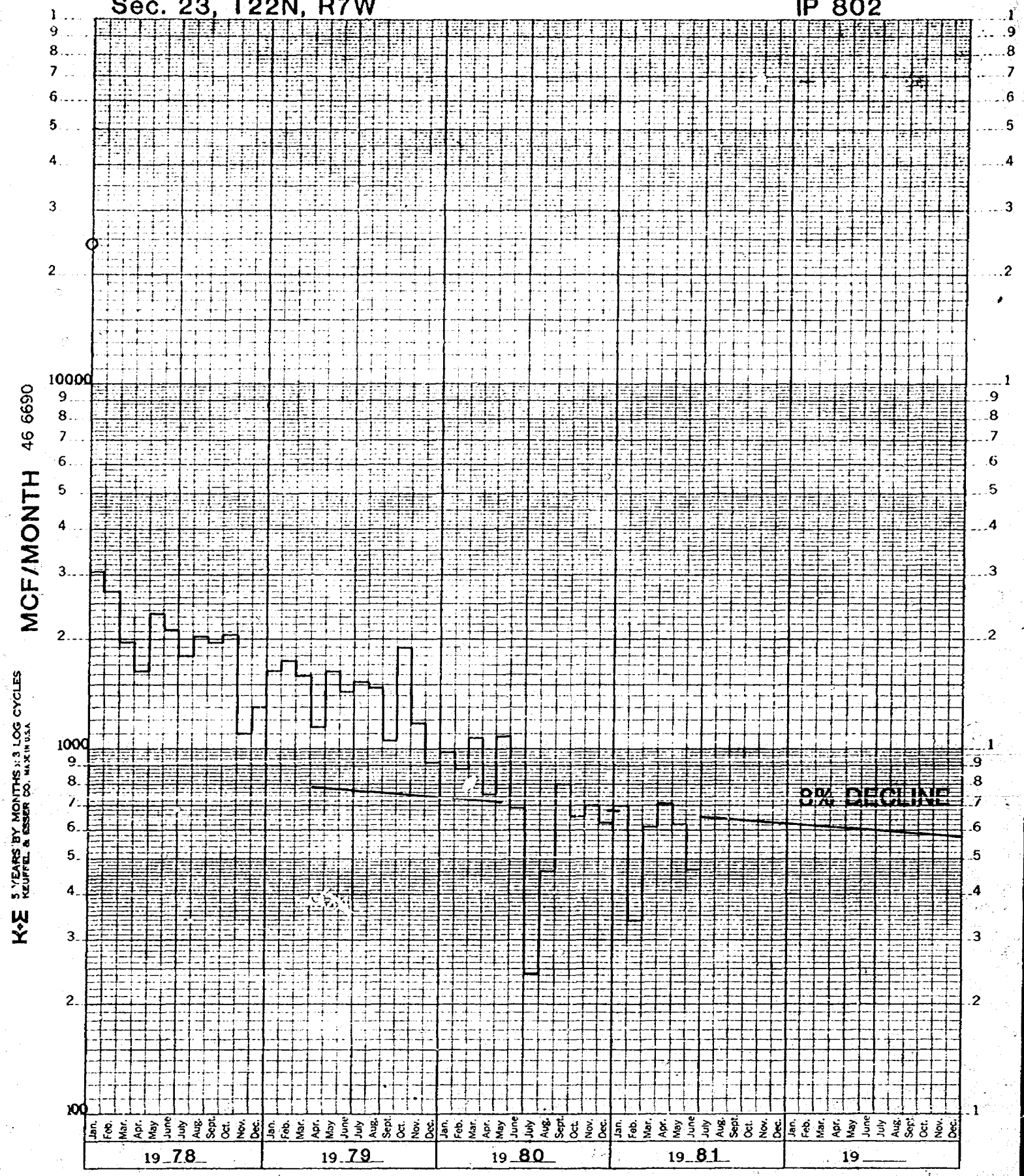


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RUSTY NAVAJO 2

Sec. 23, T22N, R7W

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IP 348

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GULF FEDERAL 2

Sec. 11, T22N, R7W

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RUSTY NAVAJO 5

Sec. 22, T22N, R7W

IP 960

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

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RUSTY FEDERAL 1
Sec. 11T22N, R7W

IP 450

MCF/MONTH

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K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
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Apr.	Apr.	Apr.	Apr.	Apr.
May	May	May	May	May
June	June	June	June	June
July	July	July	July	July
Aug.	Aug.	Aug.	Aug.	Aug.
Sept.	Sept.	Sept.	Sept.	Sept.
Oct.	Oct.	Oct.	Oct.	Oct.
Nov.	Nov.	Nov.	Nov.	Nov.
Dec.	Dec.	Dec.	Dec.	Dec.

RUSTY FEDERAL 4
Sec. 13 T22N, R7W

IP 1423

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

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Mar.	Mar.	Mar.	Mar.	Mar.
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June	June	June	June	June
July	July	July	July	July
Aug.	Aug.	Aug.	Aug.	Aug.
Sept.	Sept.	Sept.	Sept.	Sept.
Oct.	Oct.	Oct.	Oct.	Oct.
Nov.	Nov.	Nov.	Nov.	Nov.
Dec.	Dec.	Dec.	Dec.	Dec.

RUSTY FEDERAL 2

Sec. 14 T22N, R7W

IP 457

MCF/MONTH

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K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY NAVAJO 4

Sec. 26 T22N, R7W

IP 404

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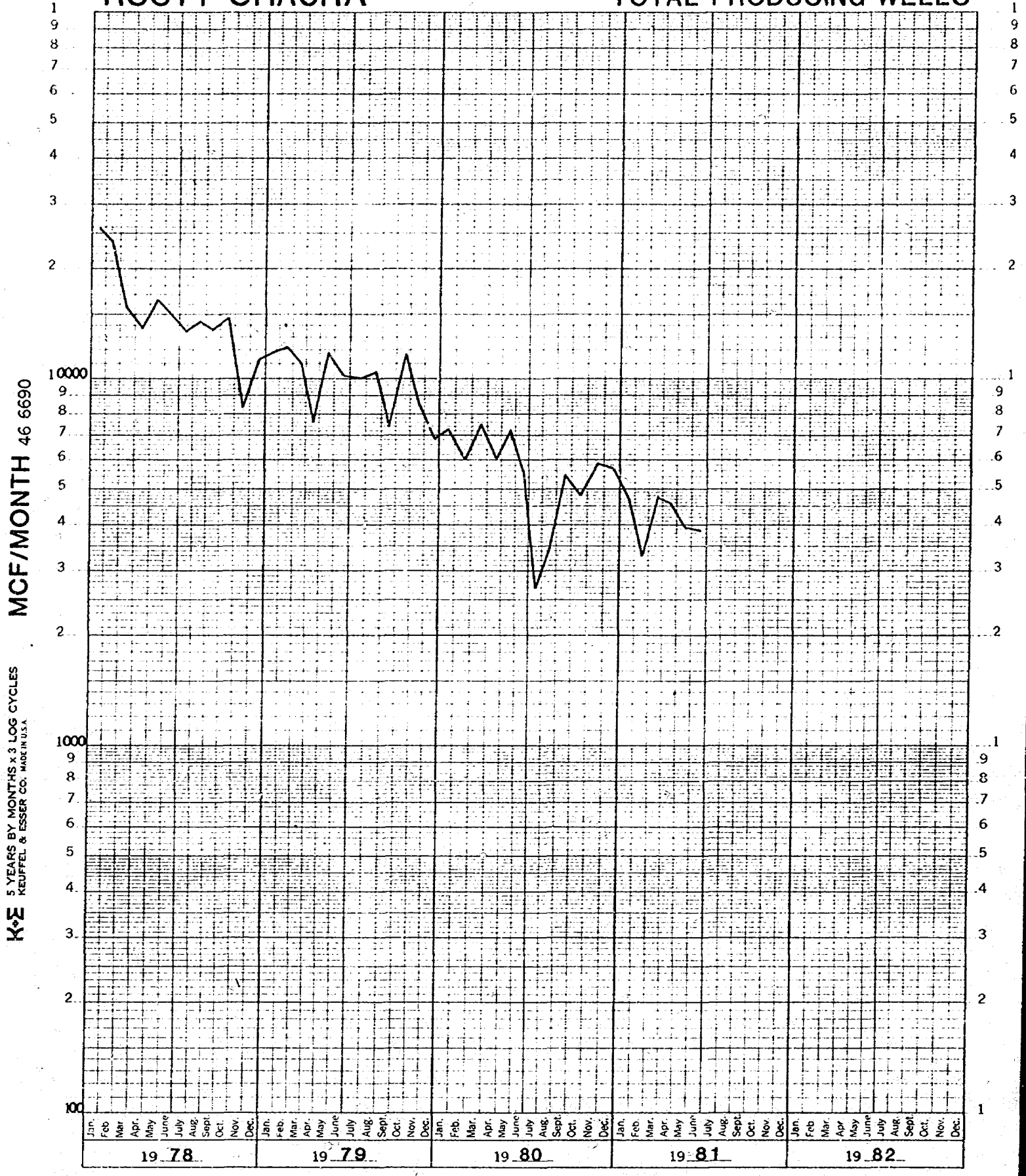
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY CHACRA

TOTAL PRODUCING WELLS

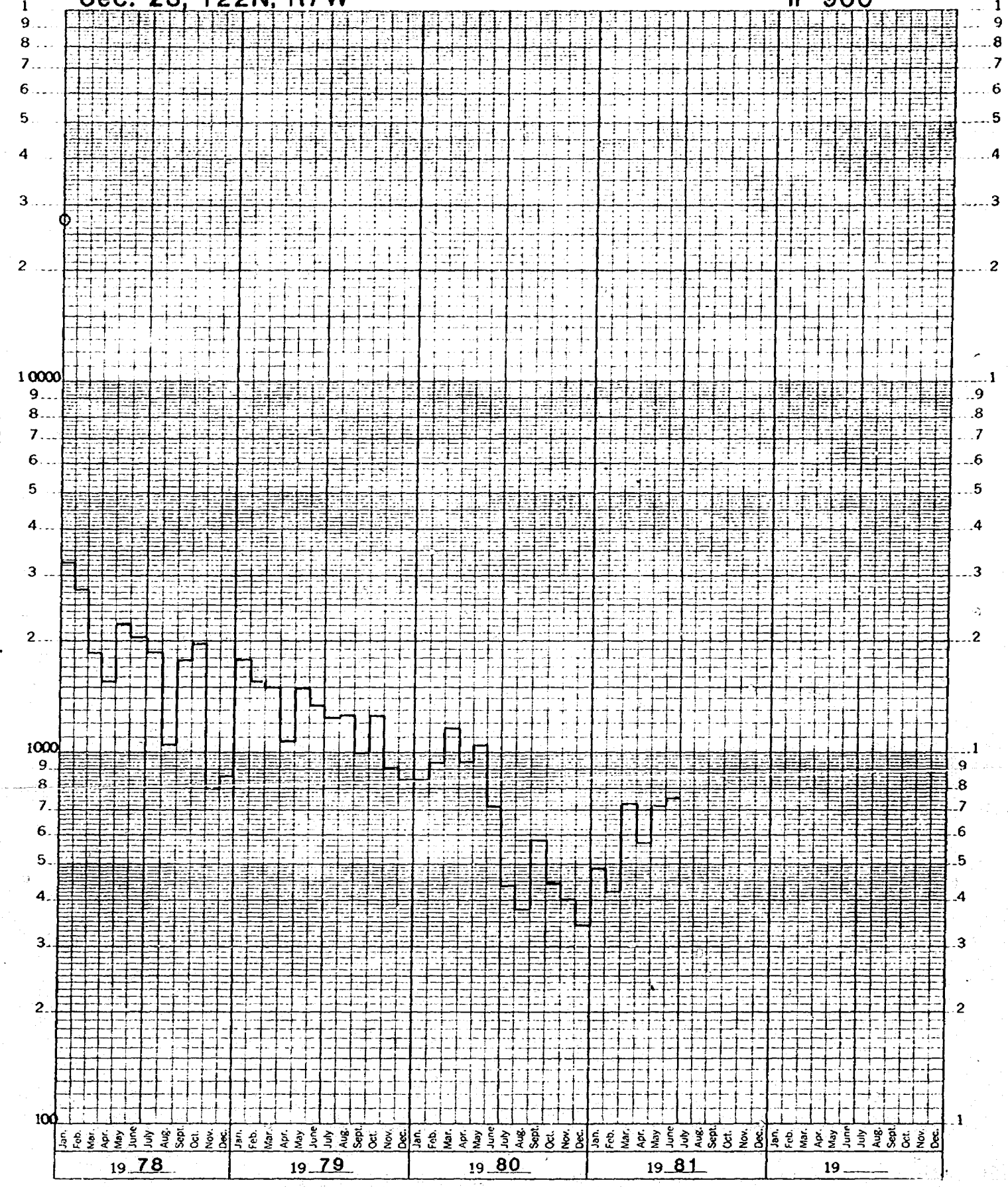


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RUSTY NAVAJO 1

Sec. 23, T22N, R7W

IP 900

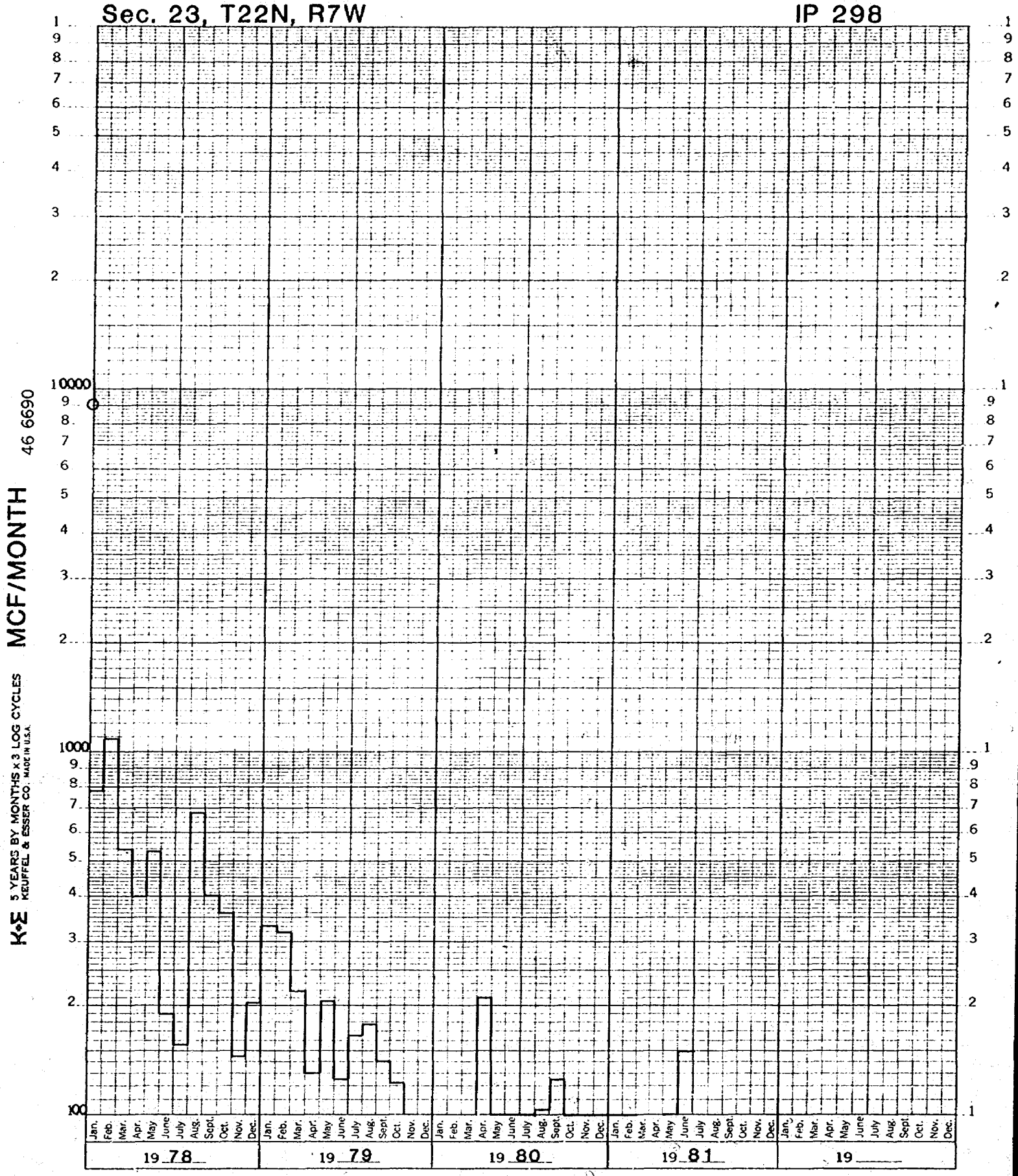


K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY NAVAJO 3

Sec. 23, T22N, R7W

IP 298



K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY FEDERAL 3

Sec. 14, T22N, R7W

IP 1472

MCF/MONTH

46 6690

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

10000
1000
100

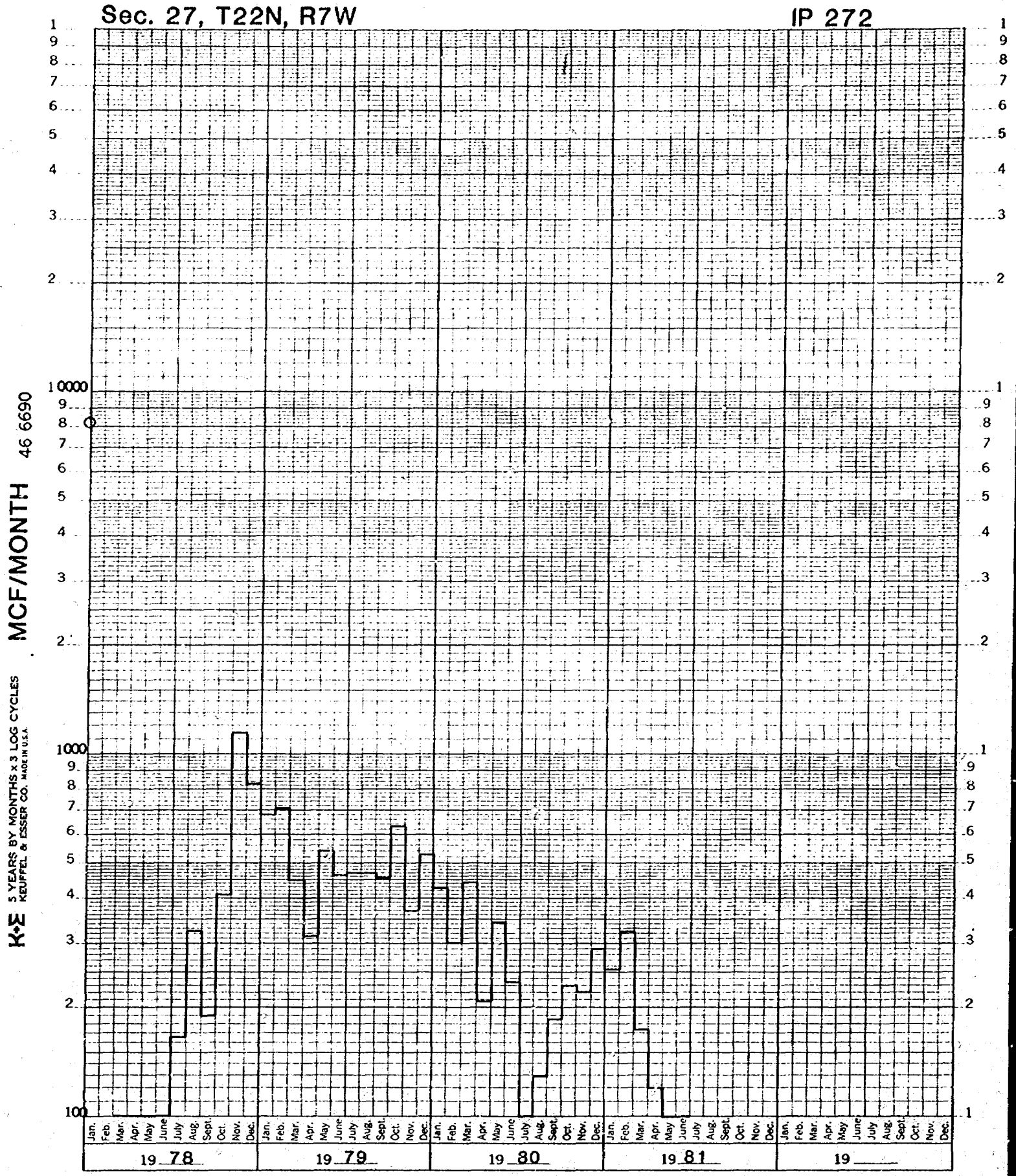
19 78 | 19 79 | 19 80 | 19 81 | 19 ____

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

RUSTY NAVAJO 6

Sec. 27, T22N, R7W

IP 272



K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

GULF FEDERAL 1

Sec. 13, T22N, R7W

IP 581

MCF/MONTH 46 6690

10000
9
8
7
6
5
4
3
2
1000
9
8
7
6
5
4
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2
100

Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

RUSTY NAVAJO 7

Sec. 22, T22N, R7W

IP 769

MCF/MONTH

46 6690

K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.

10000
1000
100

Jan Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.

19 78 | 19 79 | 19 80 | 19 81 | 19 ____

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION

RECEIVED
DEC 0 3 1981
OIL CONSERVATION DIVISION
SANTA FE

December 1, 1981

Mr. R. L. Stamets
Oil Conservation Division
State of New Mexico
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: NMOCD Case No. 7300 - Application of Dome Petroleum Corp for Designation of Dome Petroleum Corp for designation of a tight formation Sandoval County, New Mexico.

Dear Mr. Stamets:

In reference to my letter of November 25, 1981, in the above captioned matter, I mailed to you a copy of a draft order. The order enclosed with that letter was not the correct one. I am enclosing at this time the order that should have been forwarded with the November 25th letter.

I apologize for any inconvenience this may cause you.

Sincerely,

B. Hawkins

Barbara A. Hawkins
Secretary to
KENNETH BATEMAN

:bah
enclosure
cc: Kevin Tracy

812.014

Mailing Address: P.O. Box 787, Santa Fe, N.M. 87501
Street Address: 220 Otero St., Santa Fe, N.M. 87501 (505) 982-4374

L. C. White
Sumner S. Koch
William Booker Kelly
John F. McCarthy, Jr.
Kenneth Bateman
Benjamin Phillips
Larry C. White
Forrest S. Smith
John N. Patterson
Paula Tackett
Filmore E. Rose

Attorneys and Counselors at Law

RECEIVED
DEC 03 1981

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL AND CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7300
ORDER NO. _____

APPLICATION OF DOME PETROLEUM
CORP FOR DESIGNATION OF A
TIGHT FORMATION, SANDOVAL
COUNTY, NEW MEXICO

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on July 2, 1981, at Santa Fe, New Mexico before Examiner Richard L. Stamets and was readvertised and reopened at a hearing held at 9 a.m. on October 21, 1981, at Santa Fe, New Mexico before examiner Richard L. Stamets.

NOW, on this _____ day of _____, 1981, 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, Dome Petroleum Corp , requests that the Division in accordance with Section 107 of the Natural Gas Policy Act, and 18 C.F.R. §271.703, recommend to the Federal Energy Regulatory Commission that the Chacra Formation underlying the following lands situated in Sandoval County, New Mexico, hereinafter referred to as the Chacra formation, be designated as a tight formation in the said Federal Energy Regulatory Commission's regulations:

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections: 1 through 18: All
Sections: 20 through 27: All
Sections: 35 through 36: All

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 4: All
Sections: 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 36: All

(3) That the Chacra formation underlies all the above described lands; that the formation consists of fine grained and clay filled transitional shaly sands and silt stones; that the top of such formation is found at an average depth of 1658 feet below the surface of the area set forth in Finding No. 2 above; that the thickness of said formation varies with an average thickness of 300 feet within said area.

(4) That the type section for the Chacra formation for the proposed tight formation designation is found at a depth of approximately 1946 feet to 2340 feet on the Birdwell density and neutron and induction electric logs dated 9/5/80 and 9/6/80 respectively, of the Dome Federal 20-22-6 No. 2 Rusty Chacra located in Unit No. P of Section 20, Township 22 North, Range 6 West, N.M.P.M. Sandoval County, New Mexico.

(5) That the Chacra formation underlying the above described lands has been penetrated by 70 wells of which only fourteen are currently producing natural gas from the Chacra formation.

(6) That the evidence presented in this case demonstrated that no well formerly or currently completed in the Chacra formation within the proposed area may reasonably be presumed to have exhibited permeability gas productivity or crude oil productivity in excess of the following parameters:

(a) average in situ gas permeability throughout the pay section of 0.1 millidarcy; and

(b) stabilized production rates, without stimulation, against atmospheric pressure, as found in the table set out in 18 C.F.R. §271.703-(c)(2)(B) of the regulations; and

(c) production of more than five barrels of crude oil per day.

(7) That based on an analysis of available data from existing wells within the proposed area and utilizing generally and customarily accepted petroleum engineering techniques and measurements:

(a) the estimated average in situ gas permeability throughout the pay section of the Chacra formation is expected to be 0.1 millidarcy or less; and

(b) the stabilized production rate, against atmospheric, of wells completed for production in the Chacra formation, without stimulation, is not expected to exceed production levels determined by reference to well depth, as found in the table set out in 18 C.F.R. §271.703(c)(2)(B) of the regulations; and

(c) no well drilled into the Chacra formation is expected to produce, without stimulation more than five barrels of crude oil per day.

(8) That the Chacra formation underlying the area described in Paragraph 2 hereof is not being developed by infill drilling.

(9) That the evidence presented in this case demonstrated that the application of incentive pricing is reasonably necessary to stimulate further development of the proposed tight formation underlying the area described in Paragraph 2 hereof.

(10) That within the proposed area there is a recognized aquifer being the Ojo Alamo, found at an average depth of 800 feet or approximately 858 feet above the Chacra formation.

(11) That existing State of New Mexico and Federal Regulations relating to casing and cementing of wells will assure that development of the Chacra formation will not adversely affect the said aquifers.

(12) That the Chacra formation should be recommended to the Federal Energy Regulatory Commission for designation as a tight formation.

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. §271.703 of the regulations that the Chacra formation underlying the following described lands in Sandoval County, New Mexico be designated as a tight formation:

TOWNSHIP 21 NORTH, RANGE 5 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 21 NORTH, RANGE 6 WEST, NMPM
Sections: 1 through 18: All
Sections: 20 through 27: All
Sections: 35 through 36: All

Case No. 7300
Order No. _____

TOWNSHIP 21 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 4: All
Sections: 10 through 13: All

TOWNSHIP 22 NORTH, RANGE 6 WEST, NMPM
Sections: 6 through 8: All
Sections: 16 through 22: All
Sections: 26 through 36: All

TOWNSHIP 22 NORTH, RANGE 7 WEST, NMPM
Sections: 1 through 36: All

(2) The jurisdiction of this cause is hereby 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

WHITE,
KOCH, KELLY
&
McCARTHY
A PROFESSIONAL ASSOCIATION

Supplemental Info RHS

July 23, 1981

Mr. Richard Stamets
Hearing Examiner
Oil & Conservation Division
Energy & Minerals Department
State of New Mexico
State Capitol
P. O. Box 2088
Santa Fe, NM 87503

RE: Case No. 7300, Application of Dome Petroleum Corporation for a Designation of Tight Formation, Sandoval County, New Mexico

Dear Mr. Stamets:

As you requested at the hearing on July 2, 1981, my clients have prepared the enclosed information which clarifies or elaborates on the testimony introduced at the hearing.

1. Revised Exhibit 2. I enclose two copies of a revised Exhibit 2 which have been revised to clearly indicate those wells within the subject area which are not included in the application, and which have been drilled to a different productive formation, namely the Gallup formation. In that respect, the new exhibit is not materially different from the exhibit introduced at the hearing.

2. Horner Plot Calculation: (Exhibits 9, 10 and 11) At the hearing a question was raised concerning the method by which h, the formation thickness, was derived to calculate K, permeability, from the value of kh calculated from the Horner plot. Enclosed are copies of the formation density-gamma-ray logs across the pay section for each of the three wells which were the subject of extended pressure build-ups. The shaded intervals on the logs indicate the porous sands counted in the value of h, while the unshaded shale breaks were excluded. The Dome Navajo 20-22-7 #1 was slightly different in that the well was perforated and fracture treated as two separate intervals. A bridge plug is still in the well at 1525 feet, separating the two intervals in the well bore. Sands from both

L. C. White
Sumner S. Koch
William Booker Kelly
John F. McCarthy, Jr.
Kenneth Bateman
Benjamin Phillips
C. Emery Cuddy, Jr.

Larry C. White
Forrest S. Smith
Daniel H. Friedman
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Attorneys and Counselors at Law

WHITE, KOCH, KELLY & McCARTHY
A PROFESSIONAL ASSOCIATION

intervals were included in calculating h for the reason that after second fracture stimulation, both zones are experiencing communication behind the casing and therefore, all of the sands counted are contributing to production. Daily completion reports are included to show what work was done on the well. Communication between zones was shown during squeeze cemeting operations and was apparently re-established with fracture stimulation. In any event, if only the top sands are included in h, the permeability for this well would calculate to be 0.115 md resulting in an average for the three wells of 0.095 md, still within the qualifying range for NGPA Section 107 incentive prices.

3. Cores: As you know, the core permeability results in the opinion of the expert witness, did not reliably reflect in situ conditions. Enclosed are three articles from the Journal of Petroleum Technology which discuss the effect of overburden stress and water saturation on formation permeability. In situ conditions include overburden stress on the formation close to 1200 psi and water saturation of 60 percent or greater. As is shown in the article entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", the effect of 60 percent water saturation alone is enough to lower the core permeability result to 10 percent or less of the dry core value. The result is, of course, significant variation between the dry core permeability measurements and the measured in situ gas permeability obtained from the Horner pressure build-up plots.

I trust that the enclosed material will supply the information which you requested at the hearing. If not, please let me know. You requested that I draft a proposed order in this matter. I will do so shortly and forward it to you.

With very best regards, I am,

Sincerely,

Kenneth Bateman

KB:dka
cc: Mr. K. F. Tracy

Dome Navajo 20-22-7 #1
SENE Sec 20, T22N, R7
Sandoval County, New Mexico

DHC $45,700

2/1/79 WOCU

2/2/79 WOCU

2/3/79 WOCU
2/4/79 WOCU
2/5/79 WOCU

2/6/79 WOCU Will drop from report until completion unit on location

6/17 thru 6/18/79 Prep to complete. Moved in Completion rig on 6/16/79 @ 4:00 PM. Past 24 hrs MICU & RU. Cost: $270, Cum Cost: $83,631

6/19/79 Well flowing to clean up after frac. Tag PBTD @ 1697' & test to 3000 psi - OK. Displace hole w/2% KCl, swab FL to 1400' & perf 1557-67', 1574-84' & 1592-96', twelve holes total. Ran retrievable pkr & breakdown perfs w/250 gals acid and balls; good action, did not ball off. Frac'd Chacra perfs 1557-96' w/18,000 gal 20% quality foam & 46,500# 20/40 sand. Breakdown press 1500 psi, Max treating press 1500 psi, Average treating press 1500 psi. Average injection rate 15 BPM. ISDP 1250 psi 15 minutes SI 1150 psi. Job Complete 4:36 PM 6/18/79. Load to recover 128 BW. Open well to pit after 1 hr SI. Cost: $18,109, Cum Cost: $101,740.

6/20/79 Well dead. Past 24 hrs well open. Cost: $5,096, Cum Cost: $106,836 (2-3/8" tbg cost incl).

6/21/79 Well flowing. Past 24 hrs RU NOWSCO, blew 4 BW out of hole w/Nitrogen & cleaned hole. Well making estimated 100 MCF/D gas, no fluid. Cost: $150, Cum Cost: $106,986.

6/22/79 Well flowing. Past 24 hrs flowed well, well making est. 75 MCF/D gas - no fluid. Cum Cost: $106,986

6/23/79 Past 24 hrs flowed well, well making est. 75 MCF/D gas - no fluid. Cum Cost: $106,986

6/24/79 Prep to frac Upper Chacra. Past 24 hrs flowed well 6 hrs. Well making est 75 MCF/D gas - no fluid. Move in Completion Unit & Rig up. TOH w/tbg & PU retr BP. TOH & set BP @ 1550', Completion Unit Moved in @ 12 Noon 6/24/79. SDFN. Cum Cost: $107,559.

6/25/79 Past 24 hrs load hole w/wtr & 2% KCl + 2 gals Clay-stay/1000 gals. Displ 5' of sand on top of BP. Pres tested plug to 3000 psi, swab Fluid level to 1400', TOH, RU Perforators. Perf'd well as follows: 1487-1491' 5 hole, 1496 1 hole, 1504-1508 5 hole, 1512, 1524 7 holes, 1530 1 hole, 1535 1 hole. TIH w/retr pkr & set @ 1395', acidize w/250 gals 15% FE acid & 30 ball sealers, Breakdown pres 950 psi, Max treat pres 2850 psi, Avg treat pres 1500 psi. While balling off, pressure dropped from 2850 to 350 psi in 15 sec. Released pkr & attempted to tag plug. Lacked 24' getting to depth of plug set. TOH w/pkr. SDFN. Cost: $11,391, Cum Cost: $119,950.

6/26/79 Prep to squeeze Lower Chacra perfs. Past 24 hrs TIH w/tbg, had 24' of sand fill on top of BP, cleaned well to top of BP w/Nitrogen. TOH & PU pkr & retr head, TIH w/pkr, loaded hole w/KCl wtr. Set pkr @ 1540', pres test plug & tbg to 3000 psi, released pkr & set @ 1389', pres test csg to 3000 psi, Breakdown perfs w/fluid @ 900 psi w/inject. rate of 3 BPM @ 350 psi & 2 BPM @ 275 psi. TOH w/pkr & BP. Prep to set

Rusty Chacra
Dome Navajo 20-22-7 #1
990 FEL 1600 FNL
Sec. 20, T22N, R7W
Sandoval County, New Mexico

TD 3600'
AFE $113,200
Dome WI 43.75%
AFE CC $67,500

6/27/79 Prep to squeeze. Past 24 hrs RU Wireline truck, TIH w/cmt retainer & set @ 1525', TIH w/tbg to cmt ret, broke circ, latched into cmt ret, RU Halliburton, started pumping cmt, had pressure on backside immediately, displaced cmt to ret, max pres 500 psi, pulled out of ret & reversed cmt out. SWI for 2 hrs, open well & had vacuum on backside. Latched into cmt ret & pumped fluid, still had communication on backside. SDFN. Cost: $850, Cum Cost: $127,259.

6/28/79 Prep tp pressure test squeeze job. Past 24 hrs, filled hole w/8 bbls 2% KCl wtr & broke circ. Latched into cmt retainer & unable to pump thru ret. Pulled stinger out of ret & displ 35 sxs Cl "B" cmt w/2% CaCl on top of ret. Pulled 12 stds tbg, bradenhead squeezed 7 bbls cmt thru perfs. Max sqz pres 500 psi, lower tbg to top of ret & reversed 3 bbls cmt out of hole. SWI for 1½ hrs, filled hole w/fluid - less than ½ bbl to fill hole. Pulled 8 stds tbg. SDFN. Cost: $4,386, Cum Cost: $131,645.

6/29/79 Prep to squeeze well. Past 24 hrs filled hole w/5 bbls KCl wtr, pres tested well @ 1 BPM, Inj press 350 psi, TOH w/tbg & PU pkr. TIH w/pkr & set @ 905', mixed & pumped 35 sxs Cl B cmt w/2% CaCl, pumped 3½ bbls cmt into formation & hesitated squeeze, pumping ½ bbl every 15 mins, max press 800 psi. Well wouldn't squeeze, overdisplaced 2 bbls. Cost: $3,719, Cum Cost: $135,364.

6/30/79 Past 24 hrs pressure tested squeeze job. Breakdown pres 800 psi, mixed & pumped 35 sxs Cl B cmt w/2% CaCl, displ 3 bbls cmt thru perfs, well squeezed @ 1500 psi, shut well in. Prep to drill cmt out of csg. Cost: $4,438, Cum Cost: $139,802.

7/1/79 SD for Sunday

7/2/79 Prep to frac. Past 24 hrs RU to drill cmt out of csg, TIH w/bit drilled cmt from 1025-1525', circ hole clean, press test csg to 1000 psi, TOH, prep to frac. Cost: $1,860, Cum Cost: $141,662.

7/3/79 Present Operations: flow well to clean up after frac.
TIH w/tbg. Swab fluid 1350', TIH w/tbg. RU perforator, perf'd as follows: 1487-1491' 5 holes, 1496-1497', 3 holes, 1504-1508', 9 holes, 1512'-1520' 17 holes. RU Halliburton and NOWSCO. Frac thru Chacra. Perforated 1487-1520 w/22,000 gal 70% quality foam, 54,000# of 20-40 sand. Break down pressure 2400 psi. Max treating pressure 1700 psi. Average treating pressure 1400 psi. AIR 20 BPM. ISIP 1300 psi. Job complete 2:15 PM 7-2-79. Blow to recover 157 BW. Open well to pit, after 1 hr, shut in. Cost: $11,701. Cum Cost $153,363.

1/4/79 Well flowing to clean up after frac. Flwd 24 hrs, stripped tbg in hole & NU wellhead, opened well to pit. Cost: $633. Cum Cost: $153,996

7/5/79 Well flowing to clean up after frac. Flowed 24 hrs making foam & frac water. Cost: $153,996.

7/6/79 Well flowing to clean up after frac. Flowed well 24 hrs. Well making estimated 75 MCFPD 2/½" stream foamy frac water.

7/7-8-9/79 Present Operation: Flow to clean up.
Flowed 24 hours. Well making estimated 75 MCFD gas with 1/2" stream foamy water.
Cum Cost: $153,996

Rusty Chacra
Dome Navajo 20-22-7 #1
990 FEL 1600 FNL
Sec. 20, T22N, R7W
Sandoval County, New Mexico

TD 3600'
AFE $113,200
Dome WI 43.75%
AFE CC $67,500

7/10/79 Past 24 hrs flowed well 6 hrs. Well making estimated 75# MCFPD gas w/no fluid. Well shut-in.

7/11/79 Prep to clean well out, past 24 hrs WSI, Cum Cost $153,996

7/12/79 Well flowing to clean up. Past 24 hrs RU Nowsco, blew & cleaned 20' of sand out of well to PBTD @ 1525', TOH w/tbg, RU Loggers, Ran GR/CCl from 1525-1000', TIH w/tbg, Landed tbg @ 1515', NU wellhead & Open well to pit. Daily Cost: $2,598, Cum Cost: $156,594.

7/13/79 WSI. Past 24 hrs, flowed well 8 hrs, well making est. 75 MCFPD gas w/no fluid.

7/14 thru
7/16/79 Well SI past 72 hrs

7/17/79 WSI for Potential test. Cum Cost: $156,594.

7/18/79 WSI for Potential test. Cum Cost: $156,594

7/19/79 WSI for Potential Test. Cum Cost: 156,594.

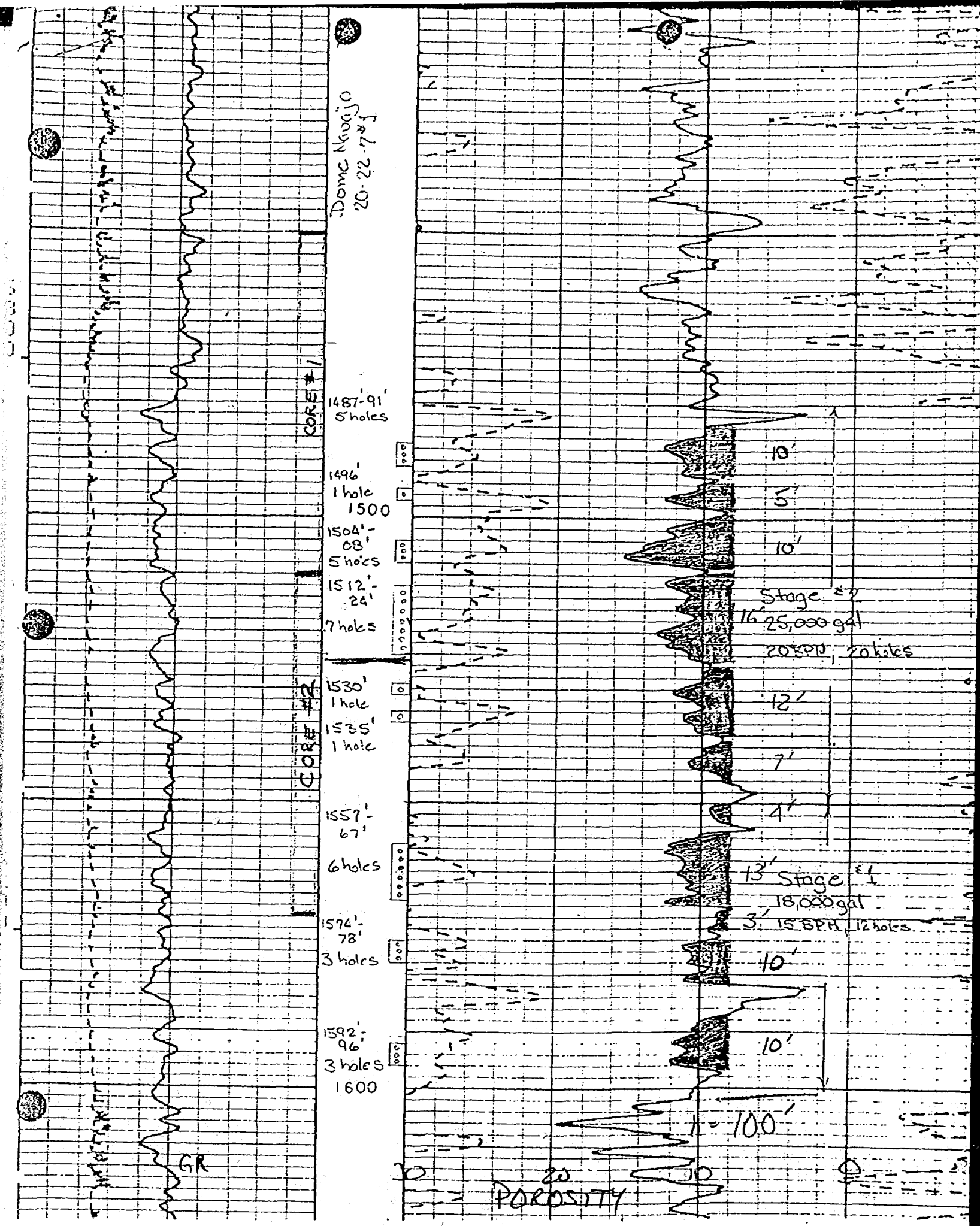
7/20/79 WSI for Potential Test

7/21 thru
7/23/79 Well SI for Potential Test. Cum Cost: $154,594.

7/24/79 Well SI for Potential Test. Cum Cost: $156,594.

7/25/79 Well SI for Potential Test. Cum Cost: $156,594.

7/26/79 WSI 8 days, SITP 320#, SICP 320#, Ran 3 hr POTENTIAL TEST thru 3/8" chk, FTP 35#. Temp 55 degrees. Well Potentialed 158 MCFPD. Cum Cost: $156,594. FINAL REPORT, WOPL.


Dome Navajo
20-22-17 #1
CORE #1
CORE #2
1487-91'
5 holes
1496'
1 hole
1500
1504'-08'
5 holes
1512'-24'
7 holes
1530'
1 hole
1535'
1 hole
1557'-67'
6 holes
1574'-78'
3 holes
1592'-96'
3 holes
1600
GR
10'
5'
10'
Stage #2
16' 25,000 gal
20 SPM, 20 holes
12'
7'
4'
13'
Stage #1
18,000 gal
3' 15 SPM, 12 holes
10'
10'
1" = 100'
20
10
POROSITY

Dome
Fed.
19-22-6
#1

Perf. 1698-1700
2 holes

Perf 1708
1 hole

Perf.
1714-22
5 holes

Perf.
1724-
36 ? holes

Perf
1738-44
4 holes

Perf.
1772-79
8 holes

Perf.
1794-96
3 holes

Perf.
1804-05
2 holes

CORE 1

CORE 2

GR

POROSITY

30 20 10 0

2'
6'
44'
30'
8'
6'
105'

STAGE 2
FOAM FRAC
32,000 # SAND

STAGE 1
FOAM FRAC
32,000 # SAND

SW/SW
Sec 13
T22-R7

1700

CHASE
RUSTY
FED. #4

1738+5178
Chacra A

1758-62

1766-68

1773-81

1789-93

1800

1798-1801

1820+5096
Chacra B

Caliper Curve

Gamma Ray

1872

1891+5025
Chacra C

1900

GR FR

BULK DENSITY

11'

43' 10%
9' 14%

37'

41'

52'

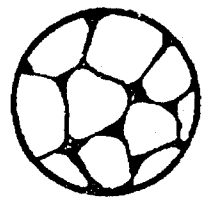
31' 10%
7' 14%

COMPENSATION

Wet

POROSITY

POROSITY
30 20 10 0



A Laboratory Study of Low-Permeability Gas Sands

F.O. Jones, SPE, Amoco Production Co.
W.W. Owens, SPE, Amoco Production Co.

Introduction

Yearly compilations of U.S. oil and gas reserves by the American Gas Assn.[1] show that U.S. gas reserves reached a maximum in 1967 of nearly 290 Tcf (8×10^{12} m^3). With the exception of the year 1970 when Prudhoe Bay reserves were added, gas reserves have declined at a near-constant rate of 10 Tcf (2.8×10^{11} m^3) per year since then. To help moderate or reverse this trend, the industry is extending its exploration and development efforts to include horizons with permeabilities in about the same range as common cement – i.e., microdarcies. The design of stimulation treatments to achieve commercial rates of production and reliable assessment of potential reserves in such low-permeability rocks demands accurate knowledge of their permeability, porosity, and flow properties. Though meager, there is sufficient information already available in the literature to suggest that some of the flow properties of these rocks differ markedly from those of more permeable rocks and, thus, require closer study.

Results of several different studies of the properties of low-permeability gas-producing horizons have been published previously. A study by Thomas and Ward[2] showed that the permeability of cores from the Pictured Cliffs and Fort Union formations were affected significantly by confining pressure. Porosities, however, were not altered greatly. They also reported that the presence of a simulated connate water saturation (about 50%) reduced gas permeabilities to only 10% to 20% of the specific gas permeability. Vairogs *et al.*[3] concluded that very low-permeability rocks are affected by stress to a greater degree than those having higher levels of permeability. This agreed with results reported earlier by McLatchie *et al.*[4]

Tannich[5] mathematically studied liquid removal from fractured gas wells in low-permeability horizons and concluded that in very low-permeability rocks, cleanup times could be extensive but that permanent formation damage was not likely. The study, however, provided no measured experimental data of the flow properties of low-permeability rocks.

Early wells drilled and cored by Amoco Production Co. in the Wattenberg field of Colorado in the Union Pacific Railroad Lease Area indicated the need for further laboratory studies of tight gas sands. Large differences in formation permeabilities, as derived from core and pressure buildup analyses, were not entirely explainable from data available in the literature. In addition, developments in stimulation design showed the need for reliable reservoir permeability values to prevent overdesign

0149-2136/80/0009-7551$00.25
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Editor's Note: This paper won the 1980 Award for Outstanding Applied Research presented May 29 by the U.S. National Committee for Rock Mechanics of the National Research Council.

Routine permeabilities of tight gas sands are shown to be greater than under reservoir conditions, often by more than a hundred-fold, because of the great relief of stress, absence of connate water, and increased gas slippage. Correlations are presented that can be used to estimate in-situ permeability from routine data.

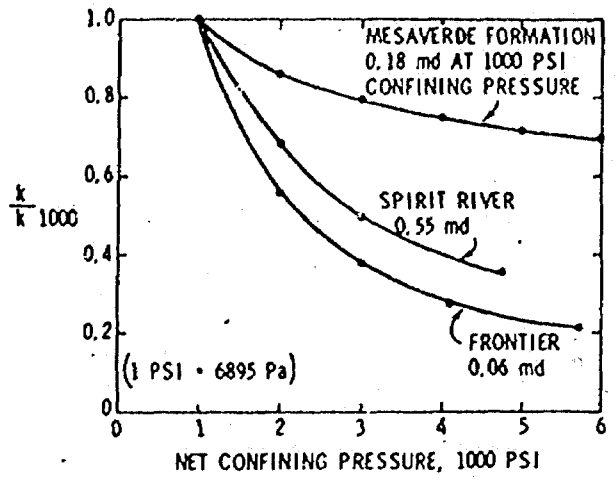


Fig. 1 – Effect of confining pressure on tight gas sand permeability.

(and cost) of massive hydraulic fracturing treatments. In addition, concern existed over the proper choice of drilling and stimulation fluids to minimize formation damage. This study is part of an ongoing Amoco study to provide answers to these and other problems that arise in the development of tight gas sand reserves.

Reported here are the results of selected laboratory tests that were designed to (1) study the factors that cause routine core-analysis permeability values to be different from those that exist in the reservoir, (2) study the range of the influence of these factors in low permeability producing horizons of interest to Amoco, (3) develop, if possible, correlations for predicting reservoir values of permeability from core analysis results, and (4) evaluate the effects of invasion of fluids of different salinities on the rate of regainment of permeability to gas.

Apparatus and Experimental Procedure

Plug samples ¾ in. (1.9 cm) in diameter and 1 in. (2.5 cm) long drilled parallel to formation bedding planes were tested in Hassler sleeve holders capable of exerting up to 10,000 psi (69 MPa) confining pressure uniformly in all directions ("hydrostatic" test conditions). Permeability to either gas or water could be measured at injection pressures up to 1,000 psi (6.9 MPa) and were measured at flow rates sufficiently low to avoid turbulence. Vacuum deaerated liquids, passing through line filters, were supplied to the cores at constant pressure by nitrogen-driven transfer cylinders designed to prevent diffusion of nitrogen into the driven liquid. Flowing pressures were measured with Bourdon gauges for gas and variable reluctance diaphragm transducers and indicators for liquid. Confining pressures were exerted by oil and were adjusted to compensate for average pore pressure to obtain a given net confining pressure.

Flow rates of liquids were measured by timing their travel in pipets. Flow rates lower than 10^{-6} cm^3/s could be measured to allow measuring permeabilities down to 10^{-6} md. Low gas flow rates were measured by timing the passage of the meniscus when displacing oil from a horizontal pipet whose tip was bent downward to discharge under oil. This arrangement – with its constant, slightly negative oil head – insured instant displacement of oil by gas and avoided complications from the action of interfacial forces at either the meniscus or pipet tip. Pipets of 1- to 2-cm^3 capacity with 0.01-cm^3 subdivisions ordinarily were used. It is important that the meniscus travel horizontally; if the oil head changes during flow measurement, gas between the core and meniscus will change volume sufficiently to introduce significant error when using small-bore pipets. However, 10-cm^3 pipets can be operated vertically with less than 1% error if volume between the core and pipet is less than 5 cm^3. Samples were liquid-saturated by evacuating them in pressure chambers for 4 hours at pressures less than 1 mm Hg (130 Pa), after which deaerated liquid was admitted and then pressured at 1,000 psi (6.9 MPa) for 16 hours to dissolve remaining traces of gas. Pore volume compressibilities were determined using the Hassler cells and measuring the liquid displaced into calibrated pipets (0.001-cm^3 subdivisions) with time allowed to obtain equilibrium at each step.

Effects of confining pressure on permeability ordinarily were measured in gas flow tests using dry cores. Permeabilities were measured at increasing confining pressure levels up usually to the reservoir net overburden pressure. [Net overburden pressure is taken to be the difference between gross overburden pressure, assumed to increase at 1.0 psi/ft (22.6 kPa/m), and reservoir fluid pressure.] Klinkenberg (no gas slippage) permeabilities were determined at the highest confining pressures by the conventional method of measuring permeabilities at more than one average flowing pressure; preliminary investigations indicated that measurements at two injection pressures provided sufficient data. Gas drive tests were performed using cores which had been saturated with formation water and whose permeability to water had been determined. For reasons discussed in a later section, nitrogen was injected, usually at 1,000 psi (6.9 MPa) (sometimes lower, if needed, to avoid turbulence) until 3,500 cm^3 (at ambient pressure) had emitted downstream. Permeability was monitored throughout the test. Holdup volumes were too great to permit measuring the rate of water production; consequently, saturation data for determining relative permeabilities could not be collected except for end points.

Results

Effect of Confining Pressure on Permeability

The large effect of confining pressure on the permeability of tight gas sands documented earlier[2-4] also was found in this study. Hydrostatically applied confining pressures equaling reservoir net overburden pressure [5,000 to 6,000 psi (34 to 41 MPa)] reduced permeability nearly 10-fold below the routine values measured under surface conditions in which confining pressure is 150 to 250 psi (1 to 1.7 MPa). Reductions ranged from less than threefold to

more than 20-fold. Typical results are shown in Fig. 1. The reason that confining pressure has greater effects on tighter sands than on more permeable ones is not well established. A popular conjecture holds that rock compression is distributed as greater fractional changes of the smaller apertures of the tight sands, the effect of which is further increased by the fact that flow depends on a higher power of the aperture dimension (round capillaries vary as the fourth power and slits by the cube of the dimension).

The experimental data were plotted in a number of ways in search of linear relationships to facilitate data handling, correlation, and, ultimately, to simplify testing. For representing behavior between 1,000 psi (6.9 MPa) and reservoir net overburden conditions, a plot of the cube root of permeability vs. the logarithm of confining pressure was found well-suited. Fig. 2 shows plots of the cube root of permeability against the logarithm of confining pressure using the data presented in Fig. 1 to illustrate the linear character of this relation. Permeability values are normalized on the basis of permeability measured at 1,000 psi (6.9 MPa) net confining pressure to allow direct comparison of the influence of confining pressure independent of permeability level; the slopes of the lines are measures of this influence. A convenient form of the equation for the relation is

$$k = k_{1,000}\left(1 - S\log\frac{P_k}{1,000}\right)^3, \quad \ldots\ldots\ldots\ldots (1)$$

where S, the magnitude of the negative slope, is given by

$$S = \frac{1 - \left(\frac{k}{k_{1,000}}\right)^{1/3}}{\log\frac{P_k}{1,000}} \quad \ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Use of the straight-line relation simplifies both testing and handling of data. Permeabilities need be measured at only two confining pressures to fix the slope parameter of the equation well enough for most engineering purposes. Measurements usually are made at 1,000 psi (6.9 MPa) and at the reservoir net overburden pressure. The S factor, the absolute value of the slope, embodies the effect of confining pressure in a single number convenient for conceptual and correlation purposes. Increasing values of S imply increasing effects of confining pressure. Moderate effects of stress, such as seen in testing higher permeability rocks, produce S factors in the vicinity of 0.1 to 0.2. Significant effects, as obtained in most tight gas sand tests, yielded S factors in the range of 0.3 to 0.6 with factors greater than 0.7 indicating large reductions. A rock decreased 10-fold in permeability below routine permeability by reservoir overburden pressure would have an S factor of approximately 0.4.

Generally, the lower the core permeability the more it is affected by confining pressure. This is illustrated in the top half of Fig. 3, a plot of S factors of Frontier formation samples against the logarithms of permeabilities measured at 1,000-psi (6.9-MPa)

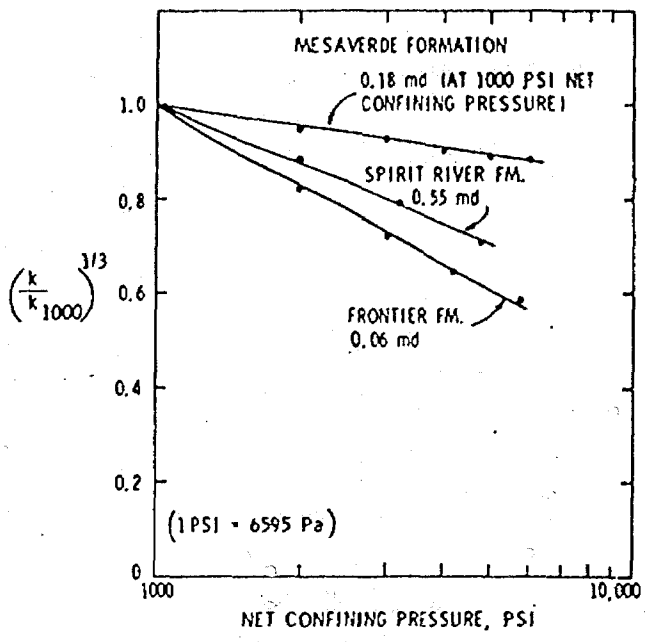


Fig. 2 – The cube root of permeability as a linear function of the logarithm of confining pressure.

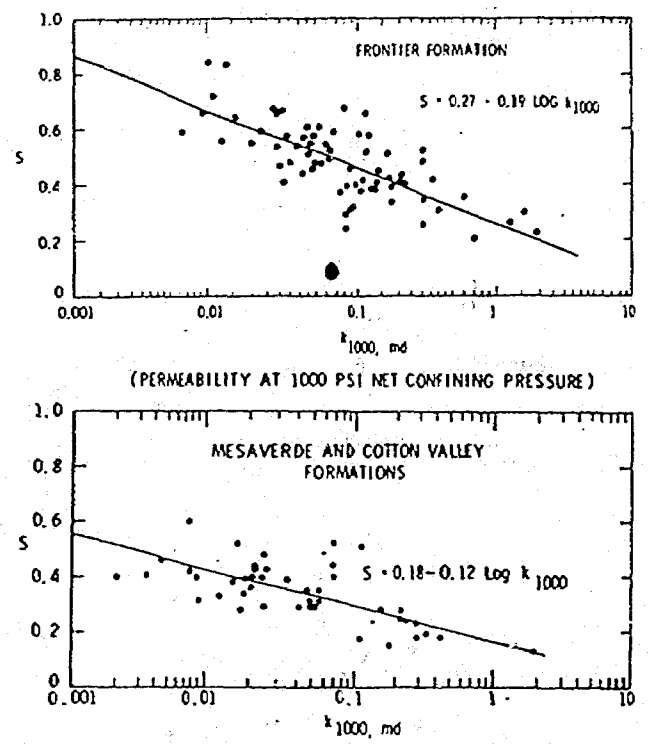


Fig. 3 – Correlation of permeability stress factor S with permeability.

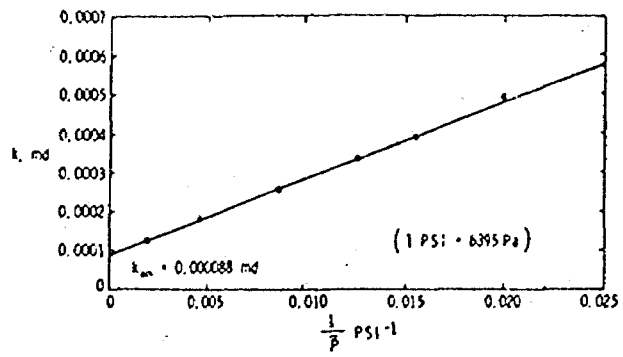


Fig. 4 – Determination of Klinkenberg permeability.

TABLE 1 – COMPARISON OF KLINKENBERG AND OIL PERMEABILITIES

Formation	Net Confining Pressure (psi)	k_∞ (md)	k_o (md)
Mesaverde	5,100	0.0092	0.0092
Mesaverde	5,200	0.0040	0.0032
Frontier	5,400	0.0018	0.0013
Frontier	5,500	0.0018	0.0010
Frontier	5,500	0.0039	0.0037
Frontier	5,500	0.0026	0.0023
Frontier	5,700	0.0066	0.0050

net confining pressure. Note also that the data, although scattered, have a linear trend. A best-fit straight line through the data affords a compact description of the average effect of confining pressure on permeability of cores from this formation. Fig. 3 shows plots of this type. Frontier formation data plotted in the upper half of the figure show effects of stress on permeability which are greater than those for the Mesaverde and Cotton Valley formations shown in the lower half.

No correlation between permeability and reduction due to confining stress was found which extended down to the 150- to 250-psi (1- to 1.7-MPa) net confining pressure condition commonly used in routine core testing; such correlations evidently must be made on an individual formation basis. Permeability measured at 1,000-psi (6.9-MPa) net confining pressure usually is between 0.4 to 0.75 times the routine permeability.

Above 2,000-psi (14-MPa) net confining pressure the logarithm of permeability vs. the logarithm of confining pressure produces fairly linear plots that possibly may be the best correlative relation for use in predicting effects by confining pressure on permeability as reservoirs are depleted.

Gas Slippage

Gas slippage, or Klinkenberg[6] effects, are large in tight gas sands. As an example, a sample with 0.001-md true, or Klinkenberg, permeability typically would exhibit about 0.003 md with gas injected at 100 psig (0.69 MPa) and exiting at atmospheric pressure, and more than 0.007 md if upstream pressure were 15 psig (103 kPa). Effective pore radii of sands with less than 0.1 md are indicated by mercury injection data and by gas slippage theory to range downward from 1 micron (1 μm) into the size realm of the mean free paths of the gas molecules. Because of this, there was concern that the conventional extrapolative procedure (in which permeability plotted vs. reciprocal arithmetic mean pressure is extrapolated to zero reciprocal pressure) for determining Klinkenberg permeability might not yield a straight line for the very low-permeability tight gas sands. The reason for this concern was that Warburg's model,[7] on which Klinkenberg based his development, assumed mean free path length was small compared with capillary radius. Klinkenberg ascribed depressions in b factors (the slope of the line connecting a data point to the Klinkenberg permeability in the above plot) determined at reduced pressure to this departure from Warburg's model. In this study, however, very good straight-line Klinkenberg plots were obtained for rocks with Klinkenberg permeabilities even less than 0.0001 md. An example is given in Fig. 4, showing the results of a test on an 0.000 088-md sample in which upstream pressures ranged from 50 to 1,000 psig (0.34 to 6.9 MPa). Both dry Klinkenberg permeabilities and specific permeabilities to a 1.3 cp (1.3 mPa·s) refined oil (Soltrol 130) were measured in tests on a series of cores in the 0.001- to 0.01-md range; the results are given in Table 1. Oil permeabilities were equal to or lower than Klinkenberg permeability in every case, averaging 25% less. The agreement is sufficiently close, however, to assume that Klinkenberg permeabilities obtained by the extrapolation procedure are satisfactory for practical application. It is not known which, if either, of the permeabilities is "correct." Oil permeabilities might be low because of interactions between the oil and rock, or Klinkenberg values may trend higher because of departure from the Warburg model.

For this study, Klinkenberg permeabilities and b factors were calculated from permeabilities measured usually at 100- and 1,000-psig (0.7- and 6.9-MPa) upstream pressure and atmospheric pressure downstream. Lower pressures were used when necessary during tests of the more-permeable samples to avoid turbulence. The measurements were made at net confining pressures equaling reservoir net overburden pressures. Confining pressure was increased sufficiently to offset average increase in pore pressure to keep confining pressure essentially constant during determination of the Klinkenberg permeability. Klinkenberg's b factor was calculated from the data using the Klinkenberg equation:

$$k_a = k_\infty \left(1 + \frac{b}{\bar{P}}\right). \quad \ldots\ldots\ldots\ldots\ldots\ldots (3)$$

As indicated by the equation, the b factor is an index of the magnitude of the gas slippage effect. It often is regarded as the fractional increase in apparent permeability which would be observed when

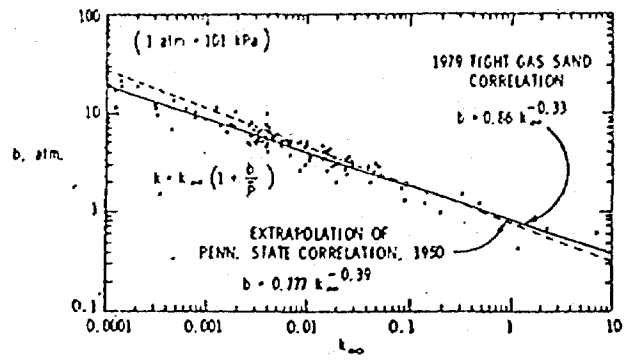


Fig. 5 – Klinkenberg *b* factor as a function of Klinkenberg permeability.

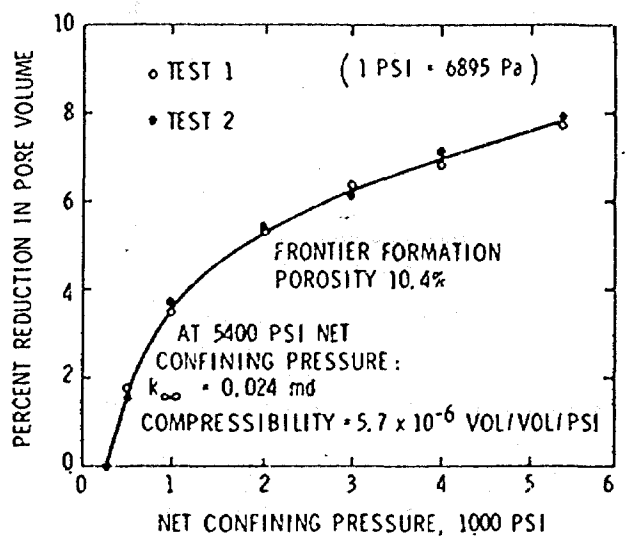


Fig. 6 – Pore volume compressibility of typical tight gas sand sample.

measuring permeability with gas at atmospheric pressure.

The results of measurements made on more than 100 tight gas sand samples are given in Fig. 5 as a plot of the logarithm of *b* factor against the logarithm of Klinkenberg permeability, a method used by Heid *et al.*[8] for presenting results of the 1950 study of Pennsylvania State U. for the API. The tight gas sand data are scattered closely about a straight line not greatly different from an extrapolation of the best-fit straight line through the higher-permeability 1950 Penn State data, the equation for which is

$$b = 0.777\, k_\infty^{-0.39} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

The best line through the tight gas sand data given in this study is

$$b = 0.86\, k_\infty^{-0.33} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

As discussed in the 1950 Penn State study, for ideal cases consisting of a parallel capillary bundle, *b* should vary inversely as the square root of permeability, which would yield a slope of −0.5 cycles/cycle. The −0.39 slope was regarded as nearly corresponding to this idealized view. The −0.33 slope obtained in this tight gas sand study is reminiscent of the cube root relation arising from Lamb's[9,10] expression for flow through ducts and suggests that apertures controlling flow in the tight gas sands may be slit-like rather than round.

The tight gas sand correlation (Eq. 5) yields values of the *b* factor sufficiently accurate for many practical purposes. The correlative power function may be substituted for *b* in Klinkenberg's equation as follows.

$$k_a = k_\infty \left(1 + \frac{0.86\, k_\infty^{-0.33}}{\bar{P}}\right). \quad \ldots\ldots\ldots\ldots (6)$$

This expression can be used as a starting point for generating graphs or numerical solutions for calculating Klinkenberg permeabilities and *b* factors from ordinary permeability data, provided the pressures used in the measurements are known. An expression originating from Eq. 6 from which k_∞ may be estimated from permeabilities k_a measured at 100-psig (0.69-MPa) upstream pressure is

$$k_\infty = 10^{(-0.0398 \log^2 k_a + 1.067 \log k_a - 0.0825)}, \quad 0.0001 \text{ md} < k_a < 1 \text{ md}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

which agrees with Eq. 6 within a few percent over the k_a range of 0.0001 to 1 md.

Pore Volume Compressibility

The chief reason for measuring pore volume compressibility was to determine if porosity values measured in routine tests were significantly greater than under reservoir conditions. It was found that the behavior of tight gas sands was similar to higher-permeability consolidated rocks and that the porosity measured at the surface was not appreciably greater than at depth. Pore volume diminished usually between 5 and 10%; a rock exhibiting 10% porosity under surface conditions would have 9.0 to 9.5% porosity in the reservoir. For many purposes, the effect of overburden pressure on porosity can be ignored. Multiplying porosity by a factor of 0.95 will correct most data sufficiently close to reservoir-condition porosity for all but the most exacting purposes. Pore volume compressibility averages about 6×10^{-6} vol/vol/psi (vol/vol/6895 Pa).

Results of a typical test are shown in Fig. 6. The percent decrease in pore volume is given as a function of increasing confining pressure. The pore volume compressibility at reservoir stress level is calculated from the slope of the curve at the reservoir net overburden pressure, taking also into account the pore volume decrease up to that point. Table 2

TABLE 2 – PORE VOLUME COMPRESSIBILITY

Formation	Porosity (%)	Net Confining Pressure (psi)	Permeability to H_2O (md)	Pore Volume Decrease (%)	Pore Volume Compressibility (vol/vol/psi x 10^6)
Mesaverde	12.8	5,200	–	5.7	5.4
Mesaverde	12.1	5,200	0.00057	5.8	5.0
Mesaverde	10.6	5,200	0.0025	6.6	6.0
Mesaverde	13.6	5,200	–	3.8	5.1
Mesaverde	13.4	5,200	0.0015	5.6	4.3
Frontier	13.2	5,400	0.0073	7.8	5
Frontier	14.3	5,700	0.00029	9.5	5.7
Frontier	11.6	5,700	0.012	10.4	3.5
Frontier	7.0	5,500	0.00091	4.3	2.7
Frontier	10.0	5,500	–	8.5	6.1
Frontier	11.1	5,500	–	10.4	9.0
Frontier	10.8	5,500	0.000069	9.8	9.1
Frontier	12.1	5,500	0.00041	4.6	3.2
Frontier	13.6	5,500	–	9.6	7.7
Frontier	13.8	5,500	–	7.1	5.9
Frontier	13.5	6,700	–	8.1	3.3
Frontier	14.0	5,700	0.00052	7.0	5.5
Muddy "J"	10.8	4,000	0.0012	8.3	9.2
Spirit River	10.2	4,000	0.0099	8.1	15.7

presents the data from a number of such tests, showing both pore volume compressibility and total effect on pore volume.

Effect of Water on Core Permeability

Water greatly reduces permeability of tight gas sands and in a manner different from its effect on higher-permeability sands. Brine causes almost as great a reduction in permeability as fresh water. For example, a 60,000-mg/L NaCl solution will reduce permeability typically 85% below Klinkenberg permeability of the dry core; introduction of distilled water will cause further reduction but only in the order of another 10% for a total reduction of about 95%. Examples of such test results are given in Table 3. A more permeable water-sensitive sand, such as Berea, would lose about 50% permeability upon introducing the above brine but would lose more than 49% additional permeability upon exposure to distilled water for a total reduction of more than 99%. Fresh water has a lesser proportionate effect on tight gas sands possibly because otherwise dispersible clays or mineral fines may tend to be mechanically locked or wedged in place in the smaller pores of the fine-textured rocks and, thereby, are inhibited from moving to form obstructions. However, the reason that even highly saline solutions can reduce permeability severely is not explained easily. There are several existing theories that alone or in combination may offer explanation. The most popular theory, although subject to much controversy concerning the magnitude of the effects, holds that water adjacent to high-energy surfaces becomes ordered to result in viscosity increase or even solidification sufficient to

TABLE 3 – EFFECT OF FRESH WATER ON PERMEABILITY

Formation	Net Confining Pressure (psi)	k_∞* (md)	k_w** (md)	k_{H_2O}† (md)
Lewis	2,000	0.0077	0.00094	0.00027
Lewis	2,000	0.0070	0.00094	0.00034
Mesaverde	5,300	0.0031	0.00032	0.00010
Mesaverde	5,300	0.0063	0.0021	0.00080
Mesaverde	5,300	0.014	0.0040	0.00064
Mesaverde	6,000	0.0039	0.00055	0.00036
Mesaverde	6,000	0.091	0.076	0.041
Mesaverde	6,000	0.0040	0.0011	0.00037
Frontier	2,000	–	0.0026	0.0009
Frontier	2,000	0.092	0.016	0.0047
Frontier	2,000	0.089	0.033	0.0090
Frontier	2,000	0.0090	0.00029	0.00013
Frontier	6,700	0.010	0.00084	0.00051
Frontier	5,700	0.0065	0.0010	0.00026
Spirit River	4,000	0.033	0.011	0.0037
Spirit River	4,000	0.0068	0.0010	0.00091
Spirit River	4,000	0.0011	0.000031	0.000022

*Klinkenberg permeability of dry core at indicated confining pressure.
**Specific permeability to formation water at indicated confining pressure.
†Specific permeability to distilled water at indicated confining pressure following flow of 50,000-mg/L NaCl solution to sensitize clays.

reduce effective pore diameter significantly. Calculations based on Poiseuille's and Lamb's laws applied to pore radii calculated from Klinkenberg b factor[6,8] indicate that fixed layers of water would need to be in the order of 100 Å (0.01 μm) or more to account for the minimum reduction observed in 0.001- to 0.1-md samples of this study.

Smectites exfoliate and most clays and many other mineral fines associate with water in going from the dry to the moistened state (even in brine) to increase the volumes of aggregates. Apertures could be reduced by this mechanism sufficient to impede flow.

The specific permeabilities to formation water of more than 100 tight gas sand samples were measured. Klinkenberg permeabilities were measured with the samples dry prior to the water flow tests. All tests were made at net confining pressure equaling reservoir net overburden pressures. The results are given in Fig. 7 as a plot of the logarithm of water permeability vs. the logarithm of Klinkenberg permeability. Two features are evident: the trend is linear and the lower the permeability the more water reduces permeability. A line centered in this data is the power function

$$k_w = k_\infty^{1.32}, \quad k < 1 \text{ md} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (8)$$

This correlative function may be used to calculate the average effect of water on permeability. Plots such as these of data from single formations or rock types may be less scattered, meaning that, in particular cases, laboratory data from samples selected from a range of permeabilities can be used to determine the exponent applicable for use in the water-effect power equation for that formation. Examination of Fig. 7 shows that the boundary of minimum effect appears well defined; a line along this boundary has a slope of about 1.13 cycles/cycle. A line bounding most of the data below 0.1-md dry Klinkenberg permeability on the side of maximum effect has a slope of about 1.5 cycles/cycle. This function can be used in conjunction with the correlations describing effects of stress and slippage to obtain estimates of in-situ gas permeability from routine permeability values. This is discussed in a later section.

Clay content was not found to correlate with effect of water on permeability. Large clay content usually forecasts large effects of water, but low clay content does not forecast low effects. Cores with large amounts of clay probably were affected most because of the low permeability resulting from the presence of clay rather than by effects of the clay itself.

The fact that water of even high salinity can seriously affect tight gas sand permeability but that, in contrast, fresh water has relatively less additional effect has obvious practical significance. Limiting entry of water during drilling or stimulation should help preserve reservoir permeability and hasten cleanup time. Filtrate invasion from muds can be reduced by maintaining mud weights close to balance, or even underbalanced, with respect to reservoir pressure. Minimizing postfracture shut-in times might also reduce fracturing-fluid invasion and

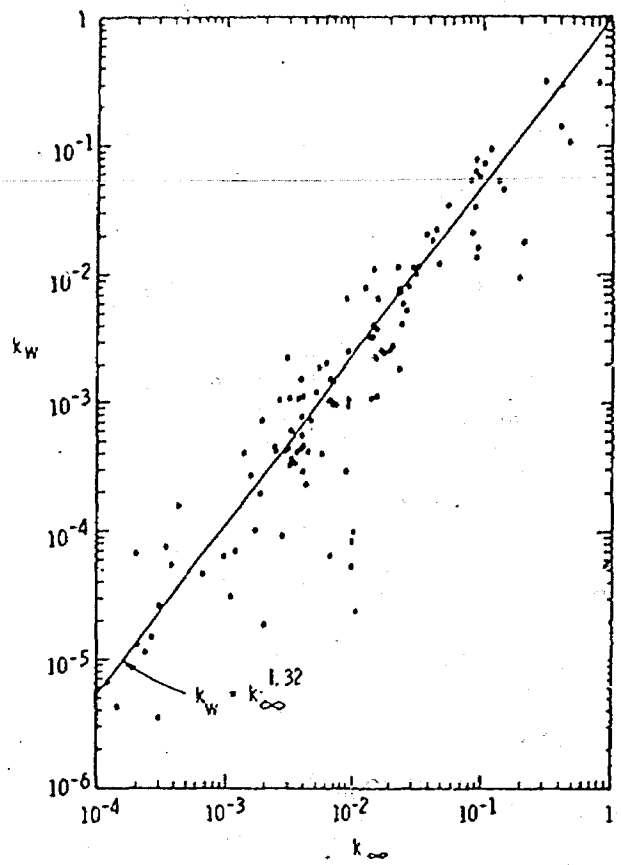


Fig. 7 – Specific water permeability as a function of Klinkenberg permeability.

prove beneficial. Another point implied, since fresh water is not a great deal more harmful than brines, is that less concern is needed regarding the chemical composition of fracturing fluids or mud filtrates.

Effect of Partial Water Saturation on Gas Permeability

Those tight gas sands whose specific water permeabilities are a great deal less than the Klinkenberg permeabilities of the dry samples also have correspondingly low gas permeabilities in the presence of simulated connate water saturations. As a first approximation, effective gas permeability under reservoir conditions can be taken as equal to specific permeability to water measured under reservoir stress conditions. Experiments demonstrating this observation are discussed as follows.

Relative permeability apparatus suitable for testing tight gas sands was not available at the initiation of the study. Exploratory gas drive experiments showed, however, that gas injected usually at 1,000 psi (6.9 MPa) into the plug samples [¾-in. (1.9-cm) diameter and 1-in. (2.5-cm) long] for a time sufficient to produce 3,500 cm^3 downstream at atmospheric pressure reduced water saturations to an average of 40% pore space. Under these conditions most of the water is removed by displacement; not more than 10% pore space of the water was evaporated. No attempt was made to measure or account for saturation gradients which may have existed. An example of the development of permeability with

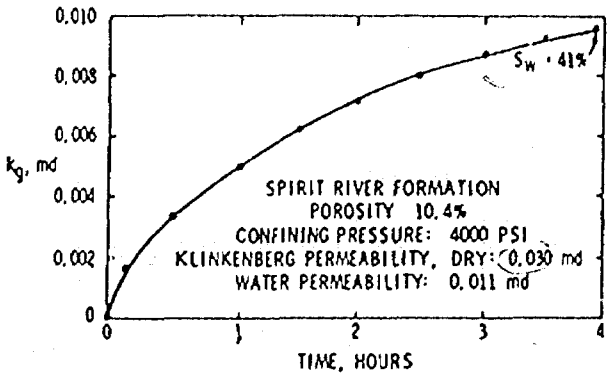


Fig. 8 – Establishment of gas permeability during displacement of water by gas.

time in a gas drive test of this type is shown in Fig. 8. Results of 22 gas drive tests are given in Table 4 in which are compared Klinkenberg permeabilities of the dry cores, specific permeabilities to water, and effective gas permeabilities at the indicated water saturations. There is a degree of bias in that testing of higher-permeability samples was favored because of the inordinate length of time required for tests of samples with less than 0.001-md permeability. Examination of the data shows that effective gas permeability in every case is nearer the specific water permeability, most often by a large margin, than to the Klinkenberg permeability of the dry sample. In more than three-fourths of the cases, effective gas permeability is within a factor of two of the specific permeability to formation water. Effective gas permeability averaged about 35% higher than specific water permeability. This suggests, as mentioned earlier, that the more easily obtained water permeability values could be used for estimating formation gas permeability. Gas drive tests are lengthy and must be attended closely, while, on the other hand, several specific water permeability tests may be conducted simultaneously by one person, usually faster than a sample per cell per day.

Combined Effects of Confining Pressure, Gas Slippage, and Water on Permeability

The individual effects of stress, gas slippage, and water on tight gas sand permeability have been described in the preceding sections. Also, the measurement of specific formation water permeability under reservoir stress conditions was suggested as a core test for estimating effective gas permeabilities under reservoir conditions. This section deals with methods of estimating reservoir-condition gas permeability using routine core analysis data.

Routine permeabilities are inexpensive and consequently plentiful, but because they are measured on dry cores at low stress levels and low flowing gas pressures, they poorly represent in-situ tight gas sand permeabilities. Routine values range from ten to more than a thousand times too high. Also, because of variability in response, routine values cannot be depended upon for comparison purposes. Frontier sand samples compared with Mesaverde sand samples, for example, commonly exhibit higher routine values but lower effective gas permeabilities under reservoir conditions of stress, presence of water saturation, and elimination of slippage. Methods for correcting routine permeability values to reservoir-condition permeability must, therefore, not only compensate for the large changes but also for the wide range of rock variability.

Two methods for estimating reservoir-condition gas permeability are suggested. The first involves

TABLE 4 – COMPARISON OF EFFECTIVE GAS PERMEABILITY TO SPECIFIC WATER PERMEABILITY

Formation	Net Confining Pressure (psi)	k_{ro} (md)	k_w (md)	k_g (md) @ S_w (%)	
Mesaverde	5,100	0.0092	0.0050	0.0028	40
Mesaverde	5,200	0.0032	0.00057	0.00079	29
Mesaverde	5,200	0.0035	0.00041	0.00010	29
Mesaverde	5,200	0.0096	0.0025	0.0033	34
Mesaverde	5,200	0.0068	0.0015	0.0020	34
Frontier	5,100	0.0067	0.000065	0.000054	44
Frontier	5,400	0.0017	0.00010	0.000070	47
Frontier	5,400	0.024	0.0073	0.0083	60
Frontier	5,700	0.0039	0.00029	0.00071	33
Frontier	5,700	0.047	0.012	0.029	60
Frontier	5,500	0.0027	0.00091	0.00075	43
Frontier	5,500	0.0012	0.000069	0.000073	49
Frontier	5,500	0.0043	0.00041	0.0011	33
Frontier	6,700	0.016	0.0011	0.0028	40
Frontier	5,700	0.010	0.00052	0.0015	52
Muddy "J"	4,000	0.0050	0.0012	0.0015	38
Cotton Valley	4,900	0.0014	0.00040	0.00026	45
Cotton Valley	4,900	0.044	0.022	0.018	32
Spirit River	4,000	0.030	0.011	0.010	41
Spirit River	4,000	0.023	0.011	0.010	38
Spirit River	4,000	0.033	0.0037*	0.0063	40
Spirit River	4,000	0.0068	0.00091*	0.0011	39

*Distilled water following 60,000-mg/L NaCl solution.

correcting sequentially for stress, slippage, and presence of connate water and is the more flexible of the two because adjustments can be made for the individual effects. The second method is derived from the first in which all effects are compounded into a single "stadium" equation (providing "ballpark" values) with two parameters that are varied simultaneously over the range from minimum to very large effects of stress, water, and slippage. Neither method, at least at present, appears capable of high precision, but the two methods do provide more reasonable values for reservoir gas permeability than the routine permeability values.

The first method requires five steps: (1) correction of routine permeability to that at 1,000-psi (6.9-MPa) confining pressure, (2) calculation of S factor (influence of pressure), (3) calculation of effect of overburden pressure using the S factor, (4) correction for gas slippage, and (5) calculation of the effect of water. Core tests over a range of permeability values for each rock type can be used to evaluate necessary parameters that then may be applied to existing routine results. For scoping studies, values of the necessary parameters may be assumed. Only three estimates are necessary: (1) the correction of routine permeability to 1,000-psi (6.9-MPa) confining pressure (a factor usually of 0.4 to 0.75), (2) selection of an S factor equation between defined upper and lower limits, S = (0.1 to 0.3) − (0.1 to 0.23) log $k_{1,000}$, and (3) selection of a water-effect exponent for Eq. 8 that also lies within the reasonably well-defined limits of 1.13 to 1.5; k_w then is assumed equal to k_g.

This method was used to generate a series of curves ranging from minimum to maximum effect of stress and water, assuming that rocks most affected by stress were also most affected by water. These calculations all generated gently curving, almost linear curves in plots of the logarithms of routine permeability against the logarithms of the calculated reservoir-condition gas permeability. Straight lines were fitted by eye to these curves, which lay within a few percent of the calculated value over the range of 0.02- to 0.55-md routine permeability. The intercepts and the slopes of these lines are the coefficients and exponents used in the stadium equation:

$$k_g = a\,k^b,$$
$$0.02 \text{ md} < k < 0.55 \text{ md} \quad \ldots\ldots\ldots\ldots\ldots (9)$$

k_g is effective gas permeability under reservoir conditions, and k is routine permeability. The coefficient a varies from 1/5 to 1/20 and the exponent c varies from 1.5 to 2.7 as the effect of stress and water increases.

Severity of Effects of Stress and Water	a	c
Minimum	1/5	1.5
Moderate	1/7.5	1.9
Great	1/12	2.3
Very great	1/20	2.7

Examples of formations having lower effect of stress and water are clean Mesaverde and Cotton Valley sands. Those moderately affected are shaly Cotton Valley sand samples and cleaner Frontier sands. Most Frontier samples studied exhibited large effects, and some experienced very large effects. Lesser effects tend to accompany increased induration, while increased clay content appears associated with larger effects. Parameters of a = 1/7.5 and c = 1.9 are reasonable values for use as first approximations in the absence of other information.

Conclusions

Results of compressibility and flow tests on more than 100 tight gas sand core samples from five formations indicate the following.

1. Confining pressure simulating net reservoir overburden pressure reduces permeability of tight gas sands two to more than 10 times, depending on permeability and rock type. The cube root of permeability was found to be a linear function of the logarithm of confining pressure; the slope of the line indicative of the intensity of the effect of stress and was found correlatable with permeability, with correlations varying with rock type. Lower permeability rocks were more affected by stress than higher permeability ones.

2. Gas slippage (Klinkenberg) effects were found to be substantial, as would be anticipated for lower permeability rocks. Slippage effects were found correlatable with an expression not greatly different from an earlier expression derived from more permeable rocks.

3. Water (including brine) severely reduced permeability with the effect more pronounced in the lower permeability rocks. This indicates that preservation of permeability in an invaded zone in a reservoir would be assisted by minimizing invasion of water during drilling and fracturing. Water permeability was found correlatable with Klinkenberg permeability.

4. Specific water permeability measured at the reservoir level of confining pressure was found useful as an approximation of effective gas permeability under conditions of reservoir stress, gas slippage, and partial water saturation.

5. Despite large permeability reductions caused by brine, reducing salinity has comparatively less additional effect, to suggest that the chemical composition of mud filtrates or fracture fluids is ordinarily of secondary importance in preventing permeability impairment.

6. Pore volume compressibility of tight gas sands is of the same order as more permeable sands. Pore volume under reservoir overburden conditions was indicated to average 93% of that under no stress for the samples tested.

7. Effects of stress, gas slippage, and water were found correlatable with permeability but not directly with clay content. Lower permeability rocks experienced large effects with both low and high clay contents. These results suggest that the large effects observed with clay-laden rocks are attributable to the low permeabilities accompanying the high clay content, not to the fact that the fine material was clay.

8. Correlations were found to enable estimating in-situ effective gas permeability from routine core analysis data by taking into account the separate effects of stress, gas slippage, and partial water saturations.

Nomenclature

a = coefficient for stadium equation
b = Klinkenberg b factor, atm
c = exponent for stadium equation
k = permeability, md
k_a = apparent gas permeability, md
k_g = effective permeability to gas, partial water saturation present, md
k_o = specific permeability to oil, md
k_w = specific permeability to water, md
k_∞ = Klinkenberg (no gas slippage) permeability, md
$k_{1,000}$ = permeability measured of dry core at 1,000-psi (6.9-MPa) net confining pressure, md
$\bar{P}$ = arithmetic mean of gas pressure in core during flow of gas, atm (Pa)
P_k = confining pressure, psi (Pa)
S = stress factor defined in text

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SI Metric Conversion Factors

atm	× 1.013 250*	E + 02	= kPa
L	× 1*		= dm^3
psi	× 6.894 757	E − 03	= MPa
torr (mm Hg, 0°C)	× 1.333 224	E − 01	= kPa

*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office March 9, 1979. Paper accepted for publication Dec. 21, 1979. Revised manuscript received July 7, 1980. Paper (SPE 7551) first presented at the SPE 1979 Symposium on Low-Permeability Gas Reservoirs, held in Denver, May 20-22.

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

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Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-5] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[4] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1-5] causing greater reductions in permeability for low-permeability rocks.[2-5] The effect of overburden pressure on relative permeability has been found to be small[1] or nonexistent.[3]

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

increasing external pressures of about 500, 1,000, 2,000, 3,000, 4,000, 5,000, and 6,000 psi. External pressures actually were somewhat higher to compensate for internal pressure. The core and stainless steel end pieces were placed in a rubber sleeve (piece of bicycle innertube) 0.1 cm thick. Rubber cement was used to seal the stainless steel end pieces to the rubber sleeve. Shrinkable plastic tubing proved unsatisfactory because high pressure was required to seal the core. The jacketed core was mounted in a high-pressure cell with distilled water as the external fluid.

Cores used in relative permeability studies were first subjected to high external pressure and then allowed to recover their initial permeability. Bulk volume, dry weight, and porosity were measured by conventional gas-expansion techniques. Cores then were subjected to a vacuum (0.3 psia) for 2 hours, immersed in water, and allowed to stand under a vacuum overnight. The cores were weighed and again subjected to vacuum overnight and weighed again to assure complete saturation. Most of the cores were completely saturated after one night. Porosity values calculated on the basis of water saturation are in good agreement with those measured by conventional gas-expansion techniques.

Water in the core was allowed to evaporate at atmospheric conditions to a saturation of about 70 percent and the core was placed in the holder for 2 hours under external pressure (100 psi above inlet) only so the water saturation was uniform. Gas permeability then was measured at three inlet pressures between 30 and 100 psia with atmospheric pressure at the outlet. This procedure was repeated for decreasing water saturations at the same external pressure. After the permeability was measured the core was weighed to determine if any water was lost. In all cases the amount lost was negligible. After the core was dried in a vacuum oven, the gas permeability at this external pressure was measured. The procedure was repeated for external pressures of 3,000 and 6,000 psi.

Results and Discussion

Effect of Overburden Pressure on Permeability

Core number, length, porosity, and initial permeability of the cores used in this research are shown in Table 1. The core number refers to the depth in feet at which the core was obtained. Typical plots of the effect of simulated overburden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

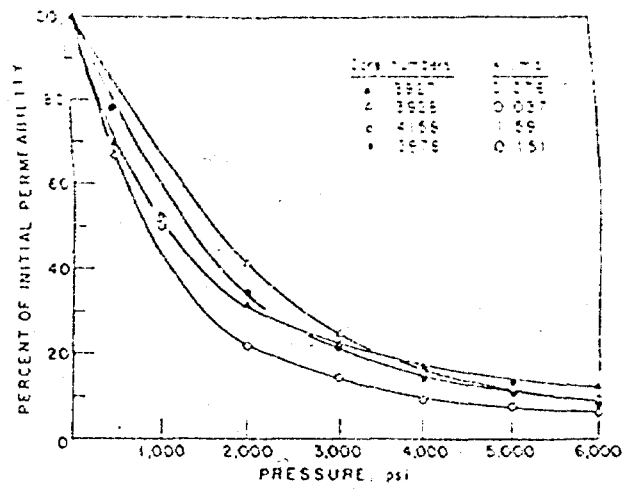


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

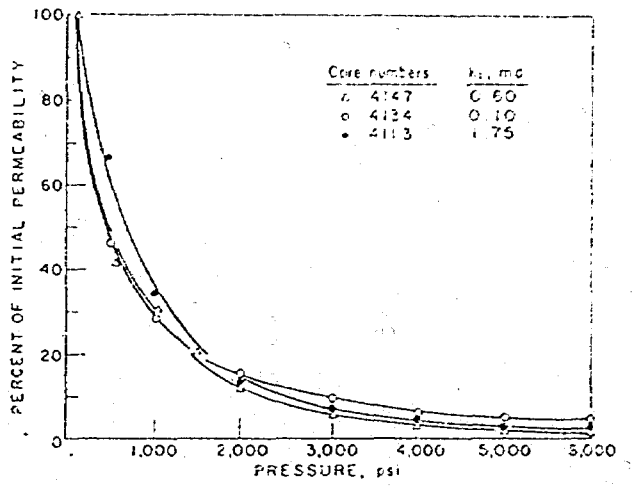


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

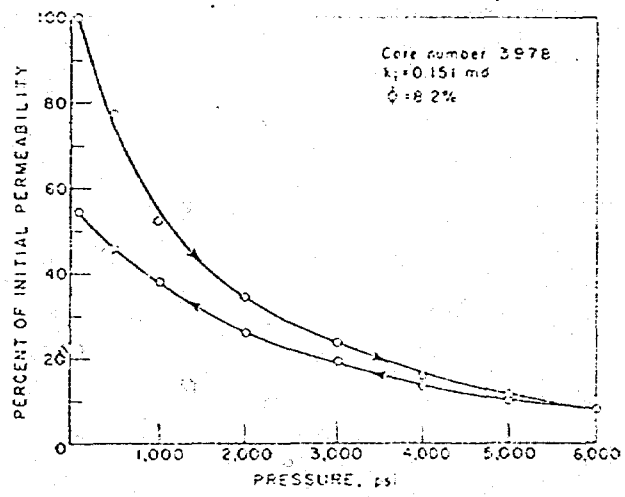


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.60	0.247	0.181	0.071	0.034	0.0186	0.0118	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.015
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.
**Slightly fractured.
†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.004
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.100	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test, it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

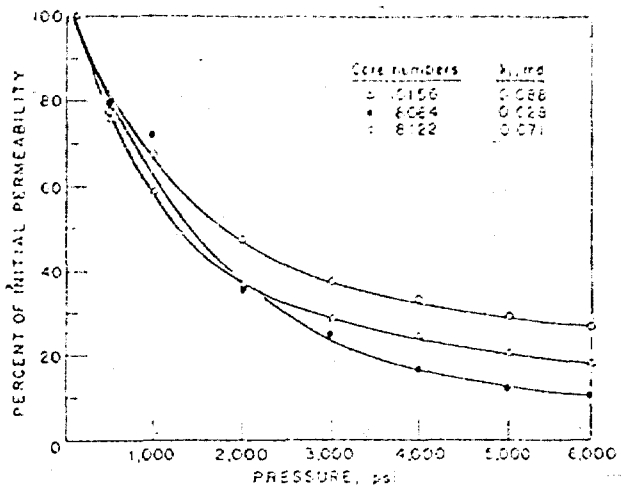


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

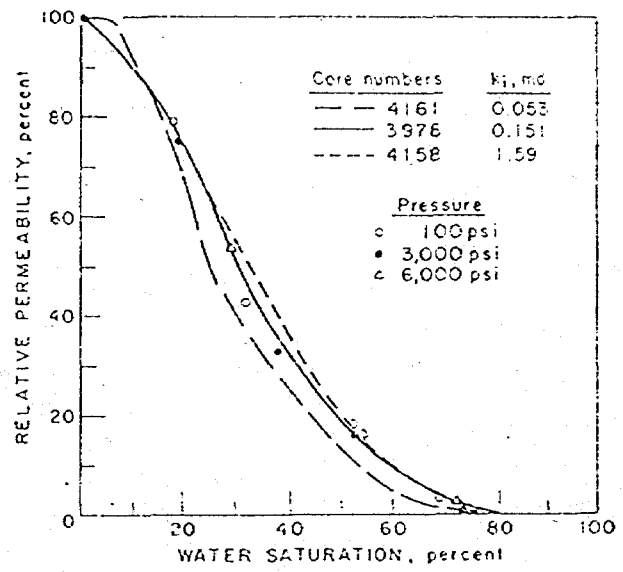


Fig. 5—Relative gas permeability of Gasbuggy cores.

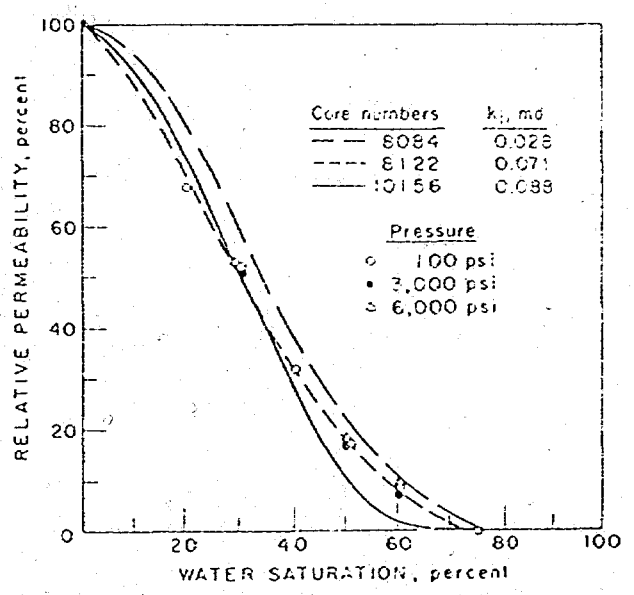


Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

Cores are not yet available from Projects Rio Blanco and WASP.

Original manuscript received in Society of Petroleum Engineers office June 16, 1971. Revised manuscript received Dec. 20, 1971. Paper (SPE 3634) was presented at SPE 46th Annual Fall Meeting, held in New Orleans, Oct. 3-6, 1971.

Conclusions

The gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Most of the decrease takes place at pressures to 3,000 psi. At 3,000 psi, the permeability of unfractured samples ranges from 14 to 37 percent of the initial permeability. In fractured samples, permeability may be reduced to as low as 6 percent of initial permeability.

Water saturation also reduces the gas permeability greatly; however, the relative permeability does not change significantly with overburden pressure.

Permeability calculated from laboratory results are in good agreement with in-situ permeabilities determined from production test data. Although not confirmed, predictions for other projects appear to be reasonable.

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Memo

From ~~DRINKARD CHILDS~~
Planner

To

9/28/81

Kevin Tracey w/ Dome Petroleum in Denver called & went over w/ me about my comments.

Oil Conservation Santa Fe, New Mexico

Memo

From
Ola Garcia
Secretary

To mike.

Kevin Tracy

303 620-3121

Dome Petroleum

Call back when you have a chance.

Perry has my economic evaluation stuff

Oil Conservation Santa Fe, New Mexico