CASE 7317: FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO

Case No.

7317

Application

Transcripts

Small Exhibits

ETC

APPLICATION OF

FOUR CORNERS GAS PRODUCERS ASSOCIATION

FOR DESIGNATION OF THE ROSA AREA OF THE BASIN DAKOTA FIELD

AS A TIGHT GAS FORMATION

RIO ARRIBA AND SAN JUAN COUNTIES, NEW MEXICO

Case No. 7313

July 29, 1981

Prepared by:

KEVIN H. McCORD
Petroleum Engineer

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION
FOR DESIGNATION OF THE ROSA AREA OF THE
BASIN DAKOTA FIELD AS A TIGHT FORMATION,
RIO ARRIBA AND SAN JUAN COUNTIES,
NEW MEXICO

The Four Corners Gas Producers Association is applying for a portion of the Basin Dakota gas field to be designated as a tight formation under Section 107 of the Natural Gas Policy Act of 1978. The proposed Rosa Tight Gas Area is located in the northeastern portion of the San Juan Basin. The area is approximately 25 miles northeast of the town of Bloomfield in northwestern New Mexico and covers portions of Rio Arriba and San Juan counties.

Exhibit No. 1 displays the Rosa Tight Gas Area on a map of the Dakota reservoir in the San Juan Basin. The Rosa Area includes approximately 270,260 acres, described as follows:

1.	T30N-R2W	Sections 1 through 36:	All
2.	T30N-R3W	Sections 1 through 36:	All
3.	T30N-R4W	Sections 1 through 36:	All
4.	T30N-R5W	Sections 1 through 36:	All
5.	T30N-R6W	Sections 1 through 36:	All
6.	T30N-R7W	Sections 1 through 36:	All
7.	T31N-R2W	Sections 1 through 36:	All
8.	T31N-R3W	Sections 1 through 36:	All
9.	T31N-R4W	Sections 1 through 36:	All
10.	T31N-R5W	Sections 1 through 36:	All
11.	T31N-R6W	Sections 1 through 36:	All
12.	T31N-R7W	Sections 1 through 36:	All

The Dakota formation in the Rosa Area meets the criteria established in Section 107 of the Natural Gas Policy Act of 1978 to be designated a tight gas formation in that (1) the estimated average in situ gas permeability throughout the pay section is expected to be 0.1 millidarcy or less, (2) the stabilized production rates, without stimulation, at atmospheric pressure of these gas wells are not expected to exceed

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 18
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

the maximum allowable production rate of 336 MCFPD for an average depth of 7950 feet to the top of the Dakota formation in this area, and (3) no well drilled into the Dakota formation in this area is expected to produce more than five barrels of crude oil per day prior to stimulation.

Exhibit No. 2 is a Dakota formation completion and production map of the proposed Rosa Tight Gas Area. The production figures presented for each producing well are initial potential, date of initial potential, average daily production for 1980, and January 1, 1981 cumulative production of gas and oil. Exhibit No. 2 also presents completion and production data from wells surrounding the proposed tight gas area. The Rosa Tight Gas Area contains 53 producing Dakota formation gas wells, while 14 wells in this area are abandoned in the Dakota at this time. A list of these wells and their production figures is presented as Exhibit No. 3. Examination of these figures indicate that these Dakota wells have not produced great quantities of natural gas, suggesting that low permeability reservoir rock could be present in the area.

Exhibit No. 4 is a type log of a Dakota well found in the Rosa Tight Gas Area. This log is from the Northwest Pipeline Corporation Rosa Unit No. 68 well, found in section 17, T31N, R5W. This well is in the north central section of the Rosa Tight Gas Area. The type log shows the entire Greenhorn and Dakota formations and part of the Mancos and Morrison formations. The type log shown is in a part of the Rosa Tight Gas Area which has exhibited better producing characteristics than the remainder of the area. Wells in remaining sections of the Rosa Area would be expected to have the same or poorer log characteristics than this type log.

The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 400 feet below the base of the Greenhorn. The formations covered in this 400 feet are the Graneros Shale, Dakota Sandstone, and Morrison formations. The Dakota formation is productive in this area, while the Morrison formation is generally water bearing. Sands in the Graneros Shale are not adequately developed in this area to be productive.

The Dakota formation has an average depth of 7950 feet in the Rosa Area, and has approximately 250 feet of gross thickness. The Dakota sandstone formation is Late Cretaceous in age with deposition occurring under both

marine and nonmarine conditions. The Dakota sandstone is the basal sequence of the southwesterly transgressing Cretaceous Sea.

The Upper Dakota sand consists of barrier beach deposits about 40 to 60 feet thick, composed of fine grained, quartz-rich sandstones characterized by an increase in grain size upward and low angle crossbedding. The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones, and sandstones. This unit represented a lagoonal type environment. The basal Dakota was deposited by a system of meandering streams creating deposits of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstones. The basal unit of Cretaceous strata in the Four Corners Area is the Burro Canyon formation. This formation was deposited in a braided stream system and is sometimes considered part of the Dakota formation. An unconformity exists between the Burro Canyon formation and the Morrison formation represented by a sharp erosional contact between the two formations.

Overall, the Dakota sand has a porosity range from 1/2 to 11-1/2% in the Rosa Area, with the average pay porosity being 4%. Silt and clay sized matrix material is present throughout the Dakota sand sequence and represents a significant portion of the bulk rock composition. This matrix material reduces the effective permeability of the formation, making it difficult to produce.

Exhibit No. 5 and 6 are log cross sections through the Rosa Area showing the continuity of the Dakota formation using the base of the Greenhorn formation for a datum line.

Permeability

The Dakota formation in the San Juan Basin is dependent on stimulation techniques to be commercially productive due to the low permeability of the reservoir rock. The Dakota in situ permeability in the Rosa Tight Gas Area is found to be less than the 0.1 millidarcy permeability cutoff used for tight gas determination. The in situ permeability for this area was calculated using data from six Dakota core analysis and was averaged to be 0.012 millidarcy.

Exhibit Nos. 7 through 12 present core analysis data used to determine the average laboratory permeability to air for Dakota formation pay zones in this area. The exhibits contain the actual core analysis reports plus summary

tables showing the analysis of cores taken from only the productive portion of the Dakota formation for each well. The cored intervals chosen for permeability averaging were determined by log examination of the interval cored for each well. Only cored intervals of sand with more than 10 ohms resistivity appearing on the Induction Resistivity log of the well were used for permeability averaging. This 10 ohms resistivity cutoff represents the average resistivity shown by the shale sections on the logs, Values less than this cutoff were not considered to be pay zones. The average laboratory permeability to air determined for the Rosa Area in this manner was 0.124 millidarcy. The actual in situ permeability of the formation is less than this laboratory determined value mainly due to the confining pressures found in the Basin Dakota reservoir.

Exhibit No. 13 presents a technical paper intitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores" written by Rex D. Thomas and Don C. Ward of the U. S. Bureau of Mines. This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs. Exhibit No. 14 explains how in situ permeability is calculated from the core analysis using the technical paper presented.

Exhibit 15 is a summary of all laboratory core analysis results, for the Rosa Tight Gas Area. An average in situ permeability value of 0.012 millidarcy was calculated from the average laboratory permeability value of 0.124 md for the Rosa Area. This in situ permeability value is well below the 0.1 millidarcy tight gas cutoff. These permeability measurements substantiate that the Dakota formation is very tight in this area and must be stimulated to obtain commercial gas production.

Stabilized Unstimulated Gas Production Rate

Obtaining stabilized unstimulated gas production rates for Dakota wells is not a standard procedure used by companies when completing their wells in the San Juan Basin. Past experience has shown that these low permeability Dakota wells must be stimulated to obtain commercial production. However, some wells drilled in the Rosa Tight Gas Area were drilled with gas as a circulation medium through the Dakota formation. This drilling procedure enables unstimulated natural gas from the Dakota formation to rise to the

surface while drilling the well.

Unstimulated natural production tests can be taken while drilling with natural gas when the gas used for circulation is shut off and the pipe rams closed on the blowout preventer stack. This enables the injected gas to blow down through a bleedoff line to the reserve pit. After injection gas has had sufficient time to return to the surface, any further gas production through this line should be unstimulated gas production from the well. A gas measuring device, such as a pitot tube, placed in the center of the natural gas production stream is used to measure the natural gas flow rate from the well. A pitot tube measures the impact pressure of the gas flow rate which is used to determine the velocity of the gas. This gas velocity, combined with the known area of the blowoff line is used to calculate the flowrate of gas through the line. Natural unstimulated gas production tests performed in this manner were found for 14 wells in the Rosa Area.

The results of these unstimulated gas production tests are presented in Exhibit 16. These gas flowrates range from rates too small to measure to 2174 MCF of natural gas per day. The average unstimulated gas production rate is 423 MCFGPD. This value is larger than the 336 MCFGPD limit for tight gas at an average depth of 7950 feet. On an individual well basis, 6 wells meet the unstimulated natural production requirement, with 3 wells just at the limit, and 5 wells being over the 336 MCFGPD limit.

Testing natural gas wells in this manner is not very accurate, but it can give the tester some idea if a well will be gas productive or not. The exact nature of these tests have many factors which leave their results questionable:

(1) The Mesa Verde formation is also productive in the Rosa Tight gas area. While the Dakota formation is open to flow to the surface during the natural flow test, the Mesa Verde can also be producing at the same time. There is no way to seperate the production from each zone using a natural production test conducted in this manner.

(2) The length of these unstimulated production tests are not long enough to establish a stabilized production rate. This length of test can by no means be considered to be a stabilized production test of the well's productivity.

(3) The natural gas injected into the well for circulating purposes can also cause erroneous results if this gas is still returning to the surface while the test is being taken.

It is reasonable to assume that the three test uncertainties presented above could all contribute to make unstimulated production tests performed in this manner report erroneously high production rates. This assumption is

supported by well production data presented in Exhibit 16.

The well listed as number 8, the Northwest Pipeline Corporation San Juan 30-5 Unit No. 47 well shows an unstimulated natural gas production rate of 2174 MCFGPD. After fracturing, the initial production for this well was 1610 MCFGPD. The initial potential for a well is calculated from a 3 hour flow test following a 7 day pressure buildup, which is a more controlled and accurate test than the pitot tube test. This, combined with the fact that an after frac production test should definitely not be lower than the unstimulated production test, indicates the unstimulated production test is probably in error.

Exhibit 16 also presents a 13 well average unstimulated production rate which excludes the erroneous rate found for the San Juan 30-5 Unit No. 47 well. This 13 well average rate is 288 MCFGPD, which is below the 336 MCFGPD rate limit for tight gas determination in the Rosa Area. Due to the uncertain nature of the unstimulated production rate testing process, this 288 MCFGPD production rate, while below tight gas guidelines, is still thought to be higher than the actual average unstimulated gas production rate for the area.

In order to test the validity of this natural production figure, Darcy's Law was used to calculate an unstimulated gas flow rate using the average in situ permeability value of 0.012 millidarcy calculated for the Dakota formation in this area from core analysis study. Exhibit No. 17 presents this calculation and shows that an initial unstimulated gas flow rate of 39.5 MCFGPD is associated with the average in situ permeability of 0.012 millidarcy for the Rosa Area.

The calculated unstimulated gas production rate and the average actual unstimulated gas production rate (excluding the erroneous production rate mentioned previously) are both less than the 336 MCFGPD limit for a tight gas reservoir in the Rosa Area. As a result of these calculations, the unstimulated natural gas production rate from the Dakota formation in the Rosa Area is not expected to exceed 336 MCF of gas per day.

Stabilized Unstimulated Oil Production Rate

The Natural gas produced from the Rosa Tight Gas area is virtually dry gas, having very little, if any, oil or condensate production associated with it. Exhibits No. 2 and 3 show that only one well, the Northwest Pipeline

Corporation Rosa Unit No. 56, has reported any oil production associated with its' gas production. This well has only produced 26 barrels of oil since 1976. These dry gas production figures indicate that no well drilled in the Rosa Tight Gas Area is expected to produce, without stimulation, more than five barrels of crude oil per day.

Fresh Water Protection

Existing State and Federal regulations will assure that development of the Dakota formation will not adversely affect or impair any fresh water acquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Regulations require that casing programs be designed to seal off potential water bearing formations from oil and gas producing formations. These fresh water zones exist from the surface to the base of the Ojo Alamo formation. The Ojo Alamo depth averages 2385 feet in the proposed Rosa Tight Gas Area.

Most wells drilled in the Rosa Area are drilled with natural mud to an average depth of 3700 feet. After intermediate casing is set, the remainder of the well is drilled with natural gas. Neither the natural mud or gas will contaminate any fresh water zone.

Normal casing designs in the Rosa Area consist of 9 5/8" or 10 3/4" O. D. surface casing being set from the surface to an average depth of 3700 feet. The cementing of the intermediate casing includes enough cement to cover formations to a depth above the Ojo Alamo formation. The cement covers the Pictured Cliffs, Fruitland, and Kirtland formations which are possible oil and gas bearing formations throughout the area. The production casing is cemented from total depth to a depth above the Mesa Verde formation, or to a point approximately 3000 feet above total depth. This cement covers the Dakota, Gallup, and Mesa Verde which are possible oil and gas bearing formations. A temperature survey is run after cementing the production casing to assure that all necessary zones are covered with cement. Therefore, all oil, gas and water bearing formations in this area are isolated from each other by cement and casing. The major water aquifer in the area, the Ojo Alamo formation, as well as the Pictured Cliffs, Fruitland, and Kirtland formations

is covered by cement and two strings of casing to protect them from contamination with other formations.

Stimulation of the Dakota formation involves large fracture treatments, usually consisting of a one or two percent potassium chloride water base that will not harm a fresh water aquifer. Fresh water protection is adequate even with these large stimulation treatments due to zone isolation caused by cementation. The large distance of over 5500 feet between the Dakota formation and the Ojo Alamo fresh water acquifer is additional insurance that no existing fresh water zone will be contaminated by stimulation of Dakota wells in this area.

Therefore, New Mexico and Federal regulations will protect any fresh water supply that may be affected by drilling, completing and producing the Dakota formation in the Rosa Tight Gas Area.

CONCLUSION

Evidence presented in this report substantiate the following for the Four Corners Gas Producers' proposed Rosa Tight Gas Area:

(1) The estimated average in situ gas permeability, throughout the Dakota pay section, is expected to be 0.1 millidarcy or less;

(2) For an average Dakota well depth of 7950 feet, the stabilized production rate at atmospheric pressure of wells completed for production in the Dakota formation is not expected to exceed the maximum allowable rate of 336 MCF of natural gas per day without stimulation;

(3) No well drilled into the Dakota formation in the Rosa Area is expected to produce, without stimulation, more than five barrels of crude oil per day.

The proposed Rosa Tight Gas Area meets all the specifications required as stated above, and should be designated a tight formation in the Basin Dakota pool under Section 107 of the Natural Gas Policy Act of 1978.

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. William F. Carr
Campbell, Byrd & Black
Attorneys at Law
Post Office Box 2208
Santa Fe, New Mexico

Re: CASE NO. 7317
ORDER NO. R-6883

Applicant:

Four Corners Gas Producers Association

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 Tom Kellahin, Gary Paulsc , Larry Paine

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

CASE NO. 7317
Order No. R-6883-A

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO.

NUNC PRO TUNC ORDER

BY THE DIVISION:

It appearing to the Division that Order No. R-6883 dated January 11, 1982, does not correctly state the intended order of the Division,

IT IS THEREFORE ORDERED:

(1) That Finding No. (6) on pages 2 and 3 of Order No. R-6883 is hereby corrected to read in its entirety as follows:

"(6) That the area for which a tight formation designation is sought is one of very limited development being comprised of approximately 846 proration units of which 66 are developed by one well and two by one well plus an infill well."

(2) That the corrections set forth in this order be entered nunc pro tunc as of January 11, 1982.

DONE at Santa Fe, New Mexico, on this 14th day of April, 1982.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY
Director

S E A L
fd/

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
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SECRETARY

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(505) 827-2434

April 19, 1982

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

Re: Tight Formation Applications

Dear Mr. Kilchrist:

At the request of one of your staff members, I am enclosing a copy of the transcript of the Oil Conservation Division hearing in our Case No. 7395 on the application of Curtis J. Little for designation of a tight formation in Rio Arriba County, New Mexico. The recommendation made in this case was forwarded to you as Division Order No. R-6875 dealing with the Pictured Cliffs formation.

I am also enclosing a copy of our Order No. R-6883-A which is a Nunc Pro Tunc order amending Order No. R-6883 which was previously forwarded to you for your consideration. Mr. Leonard Gruskiewicz of your staff pointed out an error in our Order No. R-6883 and this "A" order corrects that error.

Thank you for your assistance with these matters.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr

enc.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

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

April 15, 1982

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

Re: Tight Formation
Designations

Dear Mr. Kilchrist:

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

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

If we can be of further assistance, please advise.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr
enc.

United States Department of the Interior

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

RECEIVED
FEB 07 1982
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. 7317, Order No. R-6883, dated January 11, 1982, that the Dakota formation underlying the described lands in subject order in San Juan and Rio Arriba Counties, 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

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico.

CASE 7317

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:
William F. Carr, Esq.
CAMPBELL, BYRD, & BLACK P. A.
Jefferson Place
Santa Fe, New Mexico 87501

I N D E X

E X H I B I T S

MR. STAMETS: We'll call next Case 7317.

MR. PEARCE: Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, & Black, Santa Fe, appearing on behalf of the applicant.

This is a continuation of Case 7317 and I would request that the record show that Kevin McCord, who testified in the previous case, is qualified and that he is under oath in this matter.

MR. STAMETS: The record will so show.

KEVIN H. McCORD

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

DIRECT EXAMINATION

BY MR. CARR:

Q Mr. McCord, have you prepared additional exhibits for introduction in this case at the request of the Commission?

A. Yes, I have.

Q. Will you please refer to what has been marked for identification as Four Corners Exhibit A, identify this, and explain what it shows?

A. In our previous hearing there was some question as to the quality of the Dakota formation in the eastern four townships, that being 30 North, 2 West; 31, 2; 30, 3; and 31, 3.

I have prepared some information to try and show that the Dakota formation exists and has the same or poorer qualities as the rest of the Rosa Unit.

Exhibit A is an electric log, the E. L. Poteet Monero Dome No. 1. This well is located Township 31 North, Range 1 West, Section 24, so it's off your map. It's approximately six miles to the east of the area, and what I'd like to point out on Exhibit A is on page four, tops of formations, the Greenhorn, Graneros, and Dakota, are shown, the Dakota being at 2300 feet.

My purpose of this exhibit is to indicate the Dakota is present. This is to the east of the area and there is Dakota to the west of the area. I'm assuming there is Dakota formation in between.

The Dakota being at 2300 feet, which is considerably different from the average of 7950 for the Rosa tight gas area. This is due to a steep upward trend of the formation there; we're coming out of the San Juan Basin in that area.

Q Mr. McCord, will you now refer to what has been marked for identification as your Exhibit B and review this for Mr. Stamets?

A. Exhibit B presents core data from Rodney DeVilliers well, the No. 31 - 1 West Jicarilla. This well is located approximately four miles south of our four townships in question; location 29 North, 3 West, Section 21.

This presents the actual core analysis results on page two, and on page one is a summary of core analysis for this well.

This indicates that our laboratory permeability is 0.018 millidarcies and applying a 10 percent factor to this, which we considered for the rest of the Rosa Unit, results in a 0.002 millidarcy in situ permeability for this well.

I've also noted that a DST was run on this well when they were completing -- excuse me, when they were drilling it, and they estimated 15 to 20 Mcf of gas per day at the surface. I used this 0.002 millidarcy in my Darcy's Law calculation, as presented previously, and that resulted in a 9 Mcf per day flow rate.

This indicates the closeness of these

two ways of estimating natural flow.

Q Mr. McCord, have you also reviewed DS -- or cased hole DST's on wells located elsewhere but in this general area?

A. Yes, I have. I've looked at a cased hole DST run by PanAm Corporation. This is the Jicarilla No. 1 Pagosa, which is located three miles north of our four subject townships, Township 32 North, Range 3 West, Section 23.

I reviewed this cased hole DST data, attempted a Horner plot on it, and I was not able to come up with any reliable permeability information from this well. The flow mentioned during this DST, I believe they recovered 90 feet of drilling mud, which calculates to virtually no flow of reservoir fluids at all; therefor, it was a dry hole, and it indicated this area was not productive.

Q Does Southland Royalty Company also have plans in the area?

A. Yes, sir. At this time Southland Oil Company -- or excuse me, Southland Royalty is drilling the Sims Federal No. 1 Well, and this is in 30 North, 4 West, Section 13, and this is the northwest of the southeast. It is -- it was one of the wells I referred to last time as some of the new developments in the area.

Their current status, they are currently running a cased hole DST as of two days ago. Therefor, we don't have this information at this time. We will try to evaluate this information and supply it to the Conservation Division when we get this data available.

MR. CARR: Mr. Stamets, we would request that the record be held open to permit us to submit the written results of the Southland Royalty Company test as soon as it can be obtained. We had hoped to have it today, but they're doing it this week, and we'll get it to you as soon as it's possible.

MR. STAMETS: Okay, that would be fine.

A. Okay. Mr. Stamets, I'd like to point out that there were, other than the one dry hole mentioned previously in 30 North, 3 West, Section 34, a Sunray DX Oil Company Jicarilla Tribal No. 1, there were no other Dakota formation tests in these four townships; therefor, I have surrounded the area with the data I've just presented to you. This is virtually all we can come up with to try and tie this area into the rest of the Rosa Unit.

It's obviously a poor area. There's been no wells drilled in the area. The incentive prices will certainly help us to develop this area.

MR. STAMETS: So what you've given us today is basically three wells that form a triangle from 31,1, to 32, 3, to 29, 3, that seem to indicate that the Dakota formation is extant in those four townships, and that it is not any better than the formation evidence that you presented at the last hearing.

A. That is correct.

MR. STAMETS: Okay.

Q. Mr. McCord, will you now refer to Exhibit C and review this for Mr. Stamets?

A. Exhibit C is an update of the new locations in the area, updating my map of figure -- of Exhibit Number Two, presented previously.

I've noted there that we have 19 wells with some sort of current activity as of August 6th of 1981. This is -- these 19 wells are listed on pages two and three of Exhibit C, and the appropriate information following them about what has been going on during this time period.

Page one, I've summarized wells not plotted on this map. As you'll notice there, we have 16 wells that have been drilled, 3 that have just been staked. Of these 16 as of August 6th, only 4 have been completed as -- as to IP data. We have three producers in the area and one dry hole. And this is just a written list of these new wells.

MR. STAMETS: All the IP's on here are after frac?

A. Yes, sir, they are.

MR. STAMETS: Did any of these wells make any attempts to determine pre-frac flow?

A. To my knowledge, no, they did not. It's possible, digging through some of Northwest Pipeline's records, we might be able to come up with some sort of pre-frac flow rate. My feeling is that that information would be no different from the information we've already got doing the same -- same procedures.

Q. Mr. McCord, of the three producers shown on Exhibit C, do all three of these appear to be -- look like they will be economic successes?

A. Well, we have the one dry hole, which obviously is not. We have one well, the well listed as No. 4, Northwest Pipeline 30-5 No. 50, with an IP of 735 Mcf of gas per day. My economics, which I'll show later, will indicate that that will not be an economic well under 103.

Wells -- Well No. 2, Schalk 54 No. 1-E, 2170 Mcf per day, and Well 18, Rosa No. 77 for an IP of 2544 Mcf of gas per day, also I'll show later these indicate to be indicative of an average well for the area, which is what I used in my economics.

Q. Mr. McCord, will you now refer to Exhibit D and explain to Mr. Stamets what this shows?

A. All right, Exhibit D was some information supplied to me by Mitchell Energy Corp. This information is supplemental to Exhibit Number Sixteen, presented previously.

Okay, Exhibit Number Sixteen indicates a number of pre-frac natural flow tests taken in the Rosa Tight Gas Area, mainly by Northwest Pipeline Corp. These wells are generally in 30-5 and 31-6. This information supplied by Mitchell Energy Corp., as you can see from the start, pre-frac, pre-stimulation rate tests are in 31-4, 31-5, in that area, so we're talking about the northern part of the area.

So we have additional information here. This 8-well pre-stimulation average that they referred to of 119 Mcf per day, refers to their eight tests that they've taken in the northern part of the Rosa Area.

Also here, K. McCord 14 well pre-stimulation average of 423, are my results as presented in Exhibit Number Sixteen. They've averaged the entire 22 wells for 312 Mcf per day average for a Rosa Well, and I also indicated in Exhibit Sixteen, and they have here, I excluded Well No. 8 in the average, in that its production, its natural production rate of 2174 Mcf of gas per day was higher than its after frac flow rate of 1610 Mcf of gas per day. I felt that this test was in error; therefor, I deleted it from my average.

They also did the same and came up with a 224 Mcf of gas per day average for the Rosa area.

Q What is the production limitation prescribed by the Oil Conservation Division rules for a depth of 7950?

A. This is 336 Mcf of gas per day, so we're below it.

MR. STAMETS: In either event.

A. In either event.

Just additional information to try and tie in more of the acreage, to indicate that my initial -- my additional information was holding throughout the area.

Q Will you now refer to Four Corners Exhibit E and review this for Mr. Stamets?

A. Exhibit E is the economic criteria requested by the Commission. I worked with Frank Chavez on these numbers and we came up with a production rate, listed there under No. 1, for an average Rosa Well throughout the entire area, Year 1 to be 330 Mcf of gas per day; Year 2, 205; Year 3, 145; Year 4, 115; and Year 5-on with an 8-1/2 decline in our yearly production.

This forecast was constructed by using an IP of 2100 Mcf of gas per day for Rosa -- for all the average Rosa wells, or for the entire Rosa wells in the area.

They averaged 2100 Mcf of gas per day. The first month average on-line production, being in the range of 15 to 20 percent, as I pointed out previously, being 420 Mcf of gas per day. Applying a decline rate of 40 percent for Year 1, 35 percent for Year 2, 25 percent for Year 3, 15 percent for Year 4, and 8-1/2 percent for year 5 on, results in a production rate shown under 1.

Also, this is a dry gas area, so no condensate production figures were used.

This type of production rate is indicative of the area and it also results in an average ultimate natural gas production of 0.691 Bcf for 33 wells tested in the area. This was the best average production we could come up with for the area.

Once again, using this average, you assume we have no dry holes at all in the area, so this will be a high side case on economics.

The average well life for a Rosa -- for a Rosa well would be 30 years. Natural gas prices used in our economics, we started with an NGPA 103 based price of July, 1981, and this was 2.476 dollars per Mcf of gas, and we used a 10 percent per year escalation rate.

We used a BTU factor of 1.15 and for the 107 price we used double the NGPA 103 price.

In figuring taxes we used the State and Local tax rate of 9 percent and Federal Income tax rate of 50 percent.

We considered to be -- we considered to have a Federal Oil and Gas Lease, using a 12-1/2 royalty to our government. Operating costs of $3000 per year, which will escalate at 10,000 per year.

MR. CARR: 10 percent.

MR. STAMETS: How about 10 percent?

A. Excuse me, 10 percent per year -- you can read better than I can . Overhead expenses of 20 percent investment and 20 percent of yearly operating costs, and a sales delay of six months.

Page two of my economics reviews that we have reserves of .691 Bcf over a 30-year well life.

At Mr. Chavez' request we ran the economics, determined payout, determined return on investment and present worth for the projects at 103 and 107 prices, in first Case 1 and Case 2, using no discount rate there for our money.

I presented two different well costs, one of $470,000 and one of $820,000. The reason I did this, Northwest Pipeline claims that a well can be drilled and produced in the -- drilled and fraced and ready for completion for $470,000.

Case 2, I believe, is a little more realistic. Amoco, the last three wells they have drilled, have been in excess of $800,000, and the four wells that Mitchell is currently drilling, the Rosa 81 through 84, they indicate those costs are going to be well over $800,000 a well.

So there's a difference in operating practices there.

Anyway, for Case 1, $470,000 well cost, using 103 prices, payout of 3.17 years, return on investment of 7.01, with a present worth of 1.869 million dollars.

When we look at 107 prices, our payout decreases to 1.68 years, return on investment of 16.32, and a present worth of 4.438 million.

Case 2, using an $820,000 well cost, 103 prices, our payout is 5.97 years, return on investment of 3.51, with a present worth of 1.662 million.

Using 107, our payout decreases to 2.77 years, return on investment of 8.74, present worth of 4.141 million.

Now, in Case 3, I attempted to use some type of discount factor to have somewhat more reasonable numbers. It's certainly going to cost us something to invest our money in this project. 15 percent discount, we might be looking at a high side due to today's economics. A number of 20, and Mitchell suggested 22 percent in what they use, might be a better indication of -- of the -- of what this project will actually result in.

Anyway, using a 15 percent discounted money, our present worth, discounted 15 percent for our $470,000 case, considerably drops to a $253,000 present worth, versus our initial 1.869 million.

When we look at 107's instead of 4.3 million dollar present worth, that drops to 808,000 dollars.

Therefor, when you use this discounted money, due to the 30-year life of the project, your economics change considerably.

This DROI number 15 is discounted return on investment and this is nothing more than our summation of our cash flows discounted 15 percent and divided by the well cost to give an indication of -- of what type of return on investment we'd be looking at discounted.

For $470,000 this number is less than 1, 0.54; for 107 it's 1.72.

The significance of this number, when this number is zero, that means you've -- you've gotten 15 percent back on your money.

Also presented for an $820,000 well case, which is what I believe is more indicative of the cost of the wells in the area, present worth 15 for 103 price is only $39,000. Our DROI 15 is 0.05. It -- we've just broken even there.

And with a 107 price, our present worth would jump to $593,000 with DROI 15, 0.72.

I would say that a DROI of 15 in the neighborhood of 1, would be something of an economical project. Anything less than that, you might be better off putting your money elsewhere.

Also, with Mr. Chavez' request, I contacted Amoco and they supplied us with some economics for their Gallegos Canyon infill wells, and I used these as a comparison to these Rosa wells to indicate what infill wells would look like using a 103 price for an established 103 economic area.

There were somewhat different parameters used. Our average well cost for these wells is approximately $420,000, and this was taken from ten infill well locations scattered throughout the Gallegos Canyon area.

BTU factor used was 1.1. This is wet gas that they produce. We did not use a condensation -- or condensate production in our economics. Reserves for these wells, approximately 1.176 Bcf with a well life of 40 years.

103 prices, a payout of 2.73 years, return on investment of 16.04, and undiscounted present worth of $3,820,000.

When you use our 15 percent discounted numbers, present worth 15, $440,000, and discounted return on investment 15 of 1.05.

Comparing that with our $820,000 there is certainly quite a difference in the economics there.

Q. Mr. McCord, it would appear, then, that the Gallegos Canyon infill wells are more economical to drill and produce than the Rosa area?

A. That is correct.

Q. And all of these calculations are based on the assumption that you -- all the wells you drill are in fact producers?

A. Once again, yes, that's -- this is probably a high side because there are numerous dry holes in this area, and this assumes every well you drill will be a producer, producing .691 Bcf.

Q. In your opinion, without the incentive price will the Rosa Area be developed?

A. No, sir, I don't believe it will. I believe that only wells that will be drilled under current 103 prices are the wells needed to -- to hold acreage in the area. I don't think it will be adequately developed without 107 prices.

Q. Generally, what conclusions now can you reach about the entire area which is governed by this application?

A. I'll just state again the conclusions I've drawn in my initial presentation.

The estimated average in situ gas permeability throughout our Dakota pay section in the Rosa Tight Gas Area is expected to be .1 millidarcy or less.

For an average Dakota well depth of 7900 feet, a stabilized production rate at atmospheric pressure of wells completed for production in the Dakota formation, is not expected to exceed the maximum allowable rate of 336 Mcf of natural gas per day without stimulation.

No well drilled in the Dakota formation in the Rosa Area is expected to produce without stimulation more than 5 barrels of crude oil per day; therefor, I believe that the Rosa Tight Gas Area meets all the specifications required as stated and should be designated a tight formation in the Basin Dakota Pool under Section 107 under the Natural Gas Policy Act of 1978.

Q. Mr. McCord, were Exhibits A through E compiled under your direction?

A. Yes, all but Exhibit D, which was, as I stated, presented to me by Mitchell Energy Corp.

Q And your -- does your review of these exhibits indicate that they are correct and accurately portray the data you are attempting to show?

A. Yes, they do.

MR. CARR: At this time, Mr. Stamets, we would offer Exhibits A through E.

MR. STAMETS: These exhibits will be admitted.

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

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. McCord, Exhibit E, the last page of your economic exhibit.

A. Yes, sir.

Q In Case No. 1 you're looking at what you consider to be the lowest possible well cost in the area?

A. That is correct.

Q And does your 107 situation mean that you could do -- that this is comparable to putting your money in a money market certificate with 16.32 percent interest?

A. No. Your return on investment number is not a percentage. That's -- that number is generated by taking your total cash flow generated divided by your well cost.

So your return on your investment, you're getting 16 times the money you spent, is what that number means.

That is not a percentage.

MR. CARR: Over thirty years.

A. Yes, and that's over thirty years, also.

The percentages involved are your discounted return on investment that I have presented, and what this number indicates, since I have discounted it at 15 percent, that means any number over zero will give you a -- any number greater than zero will give you more than a 15 percent return on your money, and assuming you can get 15 percent in the bank or anything to that, it's certainly a lot -- a lot better proposition to put your money in the bank and get it back that way.

Q. Can you convert, for example, in a 103 situation, the 0.54, can you convert that into a percentage rate of return?

A. Not from the figures I have here. These were the numbers supplied to me by Amoco. I don't have their printout. This was information that they considered confidential and did not want to present unless we -- we absolutely had to.

We can confer from that DROI 15 number that your return would be less -- excuse me, somewhat more than 15 percent, but the actual number, we don't have.

MR. STAMETS: Other questions of this witness?

MR. CHAVEZ: Yes, sir.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. McCord, in a discounted rate of return what does the absolute number zero indicate? Does that indicate a break even point?

A. Yes, it does.

Q. At 15 percent.

A. That's right. That would mean that your money is worth -- all that is doing is taking your future monies and bringing it to the present.

Q. Okay. The average depth for the Dakota in these townships, how did you arrive at that again?

A. I -- every well involved in the area, I took the top of the Dakota formation and we averaged that number.

A. Okay. But in the far eastern townships the slope of the Dakota is quite a bit steeper and the Dakota formation is at about 2300 feet.

A. Now, that, once again, that well is outside of the formation -- outside of the area. Now, the actual -- you're right, it is going up at a steep angle there. Where it exactly turns, we need to have a well out there to -- to show us where the Dakota is. I don't know that.

Q. Can you make some kind of projection as to the rate of dip which the -- or rate of rise towards the east throughout --

A. Not other than it's very steep. It -- it comes up real fast, and that's just -- I have not worked that much with the geology in that area.

Q. Would work such as that give you an average Dakota depth which might be shallower than what you'd use for where wells were completed and thus require a smaller volume of unstimulated flow rate?

A. That is possible, although not -- it would be -- it's my feeling we've got most of our area over here established and all our wells are established, are somewhat deeper than that. We have a small portion of our area over here to the far east that might be possibly shallower than that. If we take an average, it could bring that number down, but once again, if you weighted your average, your number would certainly be very close to what we've got. This would not be a great percentage of these wells.

Q Do you know what depth the Southland Royalty Simms Federal Well encountered the top of the Dakota?

A. No, sir, but we'll know that when we get our information. That's -- that well, they just moved the drilling rig off of it. They, in fact, they were trying to speed up their completion to get this DST data to present for this hearing, so we will have that information then.

MR. CHAVEZ: I have no further questions.

RECROSS EXAMINATION

BY MR. STAMETS:

Q Mr. McCord, in Case No. 1 on Exhibit E, is that an economic venture at the 103 price?

A. Under the 103 price that would be a very marginally economic venture. Once again, looking at your discounted return on your investment 15, that being 0.54, it's in the range between zero and one, which makes it questionable. Due to the fact, knowing how these economics were arrived at, being an average well where you drill no dry holes, you'll get .7 Bcf, it would marginally economic as it is there.

If you consider everything involved, the real chance that you could drill a dry hole, those numbers are not really realistic; they're the high side. So therefor, I would say that if it was economic, it was just on the margin of it.

The more -- the more common cost of $820,000, or more indicative cost, that's -- that's not economic, no.

Q. And the return on investment means that you get back $7.00 for every dollar you spent over a period of years?

A. Yes, sir, that's correct, over thirty years. There's a time -- that time factor means an awful lot when you consider discounted money.

Q. And if you put your money in a 15 percent money market certificate, or some such thing as that, you would -- would you be making more money than drilling this well?

A. Under 103, $470,000 case, you would make more money drilling the well.

If it was $820,000, you'd break even. So you'd be a lot better off putting your money in the bank.

Once again, assuming you have a commercial well, not a dry hole. That -- that factor is always going to be involved, because we're talking average well, and there are dry holes in the area.

The only way to counter that effect is use a success factor or to greatly increase the cost of your wells. It's something to take into account, the cost of dry holes, which would even decrease our economics even more.

Q. How does Northwest Pipeline drill such economical wells?

A. I've had that asked to me quite a few times. They have somewhat different completion practices than, say, Amoco would, but other than that, they're doing it real cheap.

Q. Does Amoco management know about the engineering of Northwest Pipeline?

A. Well, since we have a lot of Amoco management here, I would prefer not to talk about it.

I'm sure they -- they probably know that but once again, you've got a difference in philosophy of companies on how to complete these wells. Some people feel that large fracture treatments, large volume treatments, are the way to go. Other companies, such as Northwest, feel you don't need to go to all that trouble.

I guess time will tell with thirty years of Dakota well production which is best.

But other than that, it's -- it's just

a difference in philosophy of the companies.

Now that's just the stimulation costs, is a big factor there. That certainly doesn't account for all the difference in those costs. Those are just the costs reported to me.

Q. It sounds to me as though what you're saying is, that if -- if Northwest Pipeline were the operator of this entire area, and they got the 103 price, they'd be ab'e to drill it up and make money.

A. If they got the 103 price?

Q. Right.

A. If they drilled no dry holes. If they did, if they drilled dry holes, it's marginally economic right now, as presented in Case 3.

Like I said before, I feel that a DROI number less than one is somewhat questionable economics in whether you should be drilling that, because there are -- there are success factors involved.

Q. So the Exhibit E estimates that every well will be a producer and does not try to take into account a certain number of dry holes in respect to the average recovery for the entire area.

A. Correct. Once again, the way to do that or to incorporate that type of number, would -- would be to considerably increase your well costs or incorporate some type of success factor there. But once again, using this -- this type of approach, comparing the actual economics we found right here versus our Gallegos Canyon well, it shows a considerable difference in the two projects.

Q Looking at the original Exhibit Two, it appears, though, there aren't too many dry holes through the central north/south portion of the area, at least in comparison to the numbers, percentages both east and west of there, is that correct?

A. Yes, that is. My feeling there is that these are all areas held by units and to develop these units and to show to the USGS that they're adequately trying to develop these units, wells are going to have to be drilled.

Under the current pricing scheme, we certainly have less chance of finding a dry hole in this area versus drilling our exploratory wells and developing the entire acreage. I believe that's why there's been a considerable number of wells drilled in this area versus the rest of it. I think that to develop your outer areas we're going -- we're going to need some type of price incentive to have this done.

Also, another fact, these wells in the -- in the middle part of the area developed essentially on 320-

acre spacing. Other than two instances there have not been any infills drilled.

So companies don't feel it's that economical of a venture to be drilling more wells in the area.

Q. Do you feel that the ratio of dry holes will increase as you move west and east out of this central area?

A. Yes, greatly.

Q. I don't recall from the original hearing if there was any geologic evidence that was indicating that there is a fairway or something through here that was being drilled up, or these wells are simply being drilled because of GEological Survey demands on drilling, or is this where the older wells were and these wells are being drilled as stepouts.

A. I would say more in the stepout area. I don't remember presenting any fairway type areas that we -- that you just referred to. Most of these are older wells. They're stepping out, trying to, really, just -- just satisfy your unit agreement, and some type of drilling to have an adequate development of the area.

Q. In Case No. 1, with the 103 pricing, what percentage of dry holes would it require to be drilled before that process became uneconomical?

A. It wouldn't take but one, probably.

Q. One in four, one in five, one is three, one in two?

A. I imagine, at a guess, you could probably say one in eight, as far as that goes. You're talking here, once again, looking at your discounted return on investment numbers, it's marginal now assuming no dry holes. Just say using a dry hole will increase your initial well cost from $470,000 up, well, you see that doubling that money right there brings it down to just a break even point there.

So that would take, what, one dry hole in -- let's see, one dry hole in two, wouldn't it?

Q. Uh-huh. That would mean that if you had got every other hole a dry hole, it would be a break even proposition. So what would that, say, if you had one dry hole in four, it would be a money making proposition?

A. Considering that $470,000 that sounds reasonable, yes. Once again, though, that's one instance where they claim they can drill it for that -- that type of money, and we have -- and that was just a number presented to me and the last seven wells, or the last three wells Amoco has drilled and the last four wells Mitchell has drilled in the area cost $800,000, so therefor, considering that $470,000 well cost for those, it's not reasonable at all.

MR. STAMETS: Are there any other questions of this witness? Mr. Kendrick, back in the hall, we'll give you a turn.

QUESTIONS BY MR. KENDRICK:

Q Mr. McCord, the cost of development figures that you've given in the range of $400,000 to $800,000, relates only to drilling and completing the well, has no secondary recovery or, excuse me, secondary or remedial action numbers involved.

A. That's correct. Another -- the only numbers involved are therefor operating costs or just what we've used here.

We've used $3000 per year escalating at 10 percent as straight operating costs.

We've also include overhead expenses of 20 percent of investment and 20 percent of yearly operating costs, so those are also involved as expenses for the well, but no -- no remedial work.

Q If remedial action were required on one of the classes of wells, would you expect it to be needed on the cheaper original cost or the more expensive original cost?

A. That's a good question. This could be a personal feeling, but I personally think that -- that you need to put more of a fracture stimulation on these wells, which would increase your cost.

Using that as the only basis of the difference in the costs, I know there's something else involved there, too, but my feeling is that in the life of the well, this would certainly be a better completion practice to use.

But if the $470,000 well cost had a somewhat smaller size fracture stimulation, it's possible that this well might need the remdial work more than the $800,000 well, bringing up the cost.

MR. STAMETS: Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q. Mr. McCord, has Southland Royalty apprised you of their AFE cost for the Chacosa Canyon No. 1 or for the Simms Federal 1 that they are presently testing, of what their costs have been to date?

A. I haven't asked for that information but that should be easy enough to get, especially since they're going to supply us with this other information. I'm sure they'd more than happy to supply us with an AFE.

MR. STAMETS: Good, you can supply that along with the other information.

Any other questions?

MR. PLUMLEY: Yes, sir.

MR. STAMETS: Identify yourself for the record, please.

MR. PLUMLEY: I'm Byron Plumley, with Atlantic Richfield, out of Denver.

I'd like -- there was a telegram sent yesterday, I think, to the Commission, and I would like to reiterate that.

ARCO has reviewed and agrees with this application, and that ARCO would urge the Commission to approve of this application.

MR. STAMETS: All right, we appreciate that.

If there are no further questions, Mr. McCord may be excused.

Are there any other statements?

With the provision for the other information that we've discussed here, the case will be taken under advisement.

(Hearing concluded.)

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CERTIFICATE

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. 7317, heard by me on 8-26 1981.
Richard L. Stamets, Examiner
Oil Conservation Division

LIST OF EXHIBITS

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
1	Dakota Reservoir Map	Show location of Rosa Tight Gas Area with respect to Basin Dakota production.
2	Dakota Formation Well Completion and Production Map	Show production figures of completed and dry Dakota wells in and around the tight formation area.
3	Rosa Tight Gas Area Wells	List production figures of completed and dry Dakota wells in the tight formation area.
4	Type Log	Show log characteristics and depth of Dakota formation.
5	Cross Section A-A'	Show Dakota formation development in a west-east direction.
6	Cross Section B-B'	Show Dakota formation development in a north-south direction.
7	Core Analyisis Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	Show average laboratory core permeability.
8	Core Analysis El Paso Natural Gas Company San Juan 30-5 Unit No. 28-X	Show average laboratory core permeability.
9	Core Analysis El Paso Natural Gas Company San Juan 30-6 Unit No. 31	Show average laboratory core permeability.
10	Core Analysis Amoco Production Company Rosa Unit No.1	Show average laboratory core permeability.
11	Core Analysis Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	Show average laboratory core permeability.
12	Core Analysis Blackwood & Nichols, LTD. Northeast Blanco Unit No. 1	Show average laboratory core permeability.
13	Technical Paper	Present relationship between laboratory and in situ permeability.
14	Determination of In Situ Permeability	Show method of determining in situ permeability from laboratory core analysis.
15	Summary of Permeability Data	Shows summary of permeability data, average laboratory permeability and in situ permeability.
16	Natural Production Tests	Lists natural production tests taken and average results.
17	Darcy's Law Calculation	Show unstimulated gas production rate using average in situ permeability.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 3
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

EXHIBIT NO. 3

ROSA TIGHT GAS AREA WELLS

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Sunray DX Oil Co.	#1 Jicarilla Tribal	NW/NW 34 30-3	8213	09/64	D&A	---	---
El Paso Natural Gas Co.	Carson #2	NW/SW 7 30-4	8083	09/79	869/0	302/0	.055/0
El Paso Natural Gas Co.	39 San Juan 30-4 Unit	SE/NW 18 30-4	8425	02/81	2506/0	New Well	---
Coastline Petroleum	1 Schalk-76	SW/NW 25 30-4	8675	02/75	D&A	---	---
Southland Royalty Co.	#1 Carson	NW/SW 1 30-5	8030	10/69	2129/0	129/0	.518/0
Schalk Development Co.	Schalk #54	SE/NE 2 30-5	8018	01/73	2501/0	111/0	.297/0
Schalk Development Co.	Schalk #55	NE/NE 3 30-5	7940	03/73	3298/0	34/0	.126/0
Southland Royalty Co.	Cat Draw #1	SW/SW 4 30-5	7780	09/68	2074/0	SI	.186/0
Northwest Pipeline Corp.	39 San Juan 30-5 Unit	SW/NE 7 30-5	7686	07/75	1703/0	67/0	.123/0
Northwest Pipeline Corp.	37 San Juan 30-5 Unit	NE/SW 8 30-5	7688	01/74	3944/0	87/0	.503/0
Northwest Pipeline Corp.	70 San Juan 30-5 Unit	NE/NE 9 30-5	7752	12/80	1584/0	New Well	---
Northwest Pipeline Corp.	49 San Juan 30-5 Unit	SW/SW 9 30-5	7683	12/80	855/0	New Well	---
Northwest Pipeline Corp.	73 San Juan 30-5 Unit	NW/NE 10 30-5	7919	03/81	2635/0	New Well	---
Northwest Pipeline Corp.	72 San Juan 30-5 Unit	SW/SW 10 30-5	7790	04/81	2456/0	New Well	---
Schalk Development Co.	Schalk #57	NE/NW 12 30-5	8009	07/73	5107/0	148/0	.452/0
Northwest Pipeline Corp.	52 San Juan 30-5 Unit	SE/SW 15 30-5	7920	03/81	2679/0	New Well	---
Northwest Pipeline Corp.	53 San Juan 30-5 Unit	NE/SW 16 30-5	7685	12/80	1209/0	New Well	---
Northwest Pipeline Corp.	47 San Juan 30-5 Unit	NW/SW 17 30-5	7794	08/75	1610/0	129/0	.235/0

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	38 San Juan 30-5 Unit	SW/NE 18 30-5	7667	06/80	2035/0	New Well	---
Northwest Pipeline Corp.	6 San Juan 30-5 Unit	SW/SW 19 30-5	7607	03/56	P&A	---	---
Northwest Pipeline Corp.	48 San Juan 30-5 Unit	NW/NE 20 30-5	7790	01/80	3691/0	New Well	---
Northwest Pipeline Corp.	27 San Juan 30-5 Unit	SW/SW 20 30-5	7646	12/59	1309/0	24/0	.248/0
Northwest Pipeline Corp.	51 San Juan 30-5 Unit	NW/NE 21 30-5	7759	12/80	4792/0	New Well	---
Northwest Pipeline Corp.	71 San Juan 30-5 Unit	SW/SW 22 30-5	7807	12/80	2145/0	New Well	---
El Paso Natural Gas Co.	28-23-X San Juan 30-5 Unit	NE/NE 23 30-5	8075	09/59	D&A	---	---
Northwest Pipeline Corp.	38 San Juan 31-6 Unit	NE/NW 2 30-6	7832	04/81	2828/0	New Well	---
El Paso Natural Gas Co.	31 San Juan 30-6 Unit	SE/SW 33 30-6	7550	07/59	964/0	29/0	.255/0
Blackwood & Nichols	12 NE Blanco Unit	SW/NE 18 30-7	7590	06/60	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #42	SW/NE 19 31-4	not given	11/61	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #43	NW/SE 19 31-4	8158	05/62	2352/0	98/0	.064/0
Irving Pasternak	Rosa Unit #49	SW/SW 27 31-4	8430	11/63	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #63	SW/NE 30 31-4	8088	11/77	225/0	63/0	.004/0
Coastline Petroleum	1 Schalk-58	NE/SW 2 31-5	7856	08/73	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #53	NW/NE 8 31-5	7900	03/70	1043/0	126/0	.668/0
Northwest Pipeline Corp.	Rosa Unit #80	NE/SW 8 31-5	7845	03/81	2155/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #70	NW/NW 10 31-5	8162	01/66	1500/0	261/0	.248/0
Northwest Pipeline Corp.	Rosa Unit #48	SW/SE 11 31-5	8151	12/62	3207/0	326/0	.218/0
Northwest Pipeline Corp.	Rosa Unit #40	SW/NW 11 31-5	8358	07/51	3560/0	271/0	.216/0
Northwest Pipeline Corp.	Rosa Unit #61	SE/SW 13 31-5	8124	11/77	337/0	55/0	.074/0
Northwest Pipeline Corp.	Rosa Unit #65	NE/NE 17 31-5	7870	08/78	3095/0	163/0	.104/0
Northwest Pipeline Corp.	Rosa Unit #68	NW/SW 17 31-5	not given	08/80	5757/0	609/0	.093/0
Northwest Pipeline Corp.	Rosa Unit #62	NE/NW 25 31-5	8088	11/77	342/0	82/0	.106/0
Northwest Pipeline Corp.	Rosa Unit #64	NE/NE 29 31-5	7950	10/78	1843/0	175/0	.132/0
Northwest Pipeline Corp.	Rosa Unit #52	NW/NW 33 31-5	7980	02/70	2401/0	248/0	1.095/0
Northwest Pipeline Corp.	Rosa Unit #55	NE/SE 34 31-5	8056	10/74	264/0	167/0	.386/0
Northwest Pipeline Corp.	Rosa Unit #56	SW/NW 35 31-5	8200	11/75	675/0	96/0	.232/26
Northwest Pipeline Corp.	Rosa Unit #54	NE/SW 36 31-5	8284	09/74	304/0	SI	.029/0
Amoco Production Co.	Rosa Unit 35-X	NE/SW 5 31-6	7822	10/59	D&A Dak. MV Comp.	---	---
Amoco Production Co.	Rosa Unit #36	SE/NE 11 31-6	7955	12/59	P&A MV Comp.	---	---
Amoco Production Co.	Rosa Unit #1	SW/SE 11 31-6	7865	09/52	560/0 (P&A)		---
Northwest Pipeline Corp.	Rosa Unit #66	NW/SW 13 31-6	7957	08/78	4427/0	245/0	.928/0
Amoco Production Co.	Rosa Unit #69	NW/NW 16 31-6	7918	09/80	P&A	---	---
Northwest Pipeline Corp.	79 San Juan 31-6 Unit	NE/SW 22 31-6	7757	03/81	1858/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #51	NE/NW 23 31-6	7823	01/70	1385/0	170/0	.736/0
Northwest Pipeline Corp.	36 San Juan 31-6 Unit	NE/NE 27 31-6	7806	03/81	2557/0	New Well	---
Northwest Pipeline Corp.	24 San Juan 31-6 Unit	NE/SW 27 31-6	7939	12/73	1341/0	SI	.269/0
Northwest Pipeline Corp.	16 San Juan 31-6 Unit	SE/SW 33 31-6	7895	07/59	1783/0	SI	.074/0
Northwest Pipeline Corp.	33 San Juan 31-6 Unit	SW/NE 34 31-6	8712	06/80	4119/0	New Well	---
Northwest Pipeline Corp.	35 San Juan 31-6 Unit	NE/NE 35 31-6	7908	07/80	2643/0	New Well	---
Northwest Pipeline Corp.	31 San Juan 31-6 Unit	SE/SE 35 31-6	7796	06/80	3770/0	New Well	---
Northwest Pipeline Corp.	37 San Juan 31-6 Unit	SW/SE 36 31-6	7952	04/[illegible]1	2370/0	New Well	---
Blackwood & Nichols	58 NE Blanco Unit	NE/NE 13 31-7	7975	11/59	2461/0	217/0	1.387/0
Blackwood & Nichols	57 NE Blanco Unit	NE/NE 21 31-7	7780	09/59	1235/0	37/0	.44[illegible]/0
Blackwood & Nichols	55 NE Blanco Unit	NW/NE 22 31-7	7856	10/58	275/0	27/0	.182/0
Blackwood & Nichols	1 NE Blanco Unit	SE/NE 27 31-7	7792	10/52	536/0	217/0	2.398/0
Amoco Production Co.	McKay #1	NW/NE 28 31-7	7765	03/71	D&A	---	---
Blackwood & Nichols	56 NE Blanco Unit	NE/NE 34 31-7	7660	11/58	2839/0	30/0	.417/0

EXHIBIT NO. 7

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 30-5 Unit No. 27
Basin Dakota Field
SW/SW, Sec. 20, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7650-7651	1	0.01
7651-7652	1	0.01
7652-7653	1	0.01
7653-7654	1	0.02
7654-7655	1	0.01
7655-7656	1	0.02
7658-7659	1	0.02
7661-7662	1	0.03
7662-7663	1	0.02
7667-7668	1	0.02
7669-7670	1	0.01
7670-7671	1	0.02
7688-7689	1	0.01
7689-7690	1	0.01
7690-7691	1	0.60
7691-7692	1	0.01
7692-7693	1	0.01
7694-7695	1	0.02
7696-7697	1	0.25
7697-7698	1	0.01
7707-7708	1	0.01
7708-7709	1	0.02
7709-7710	1	0.03
7719-7720	1	0.01
7720-7721	1	1.51
7721-7722	1	0.07
7722-7723	1	0.25
7723-7724	1	0.10
7724-7725	1	0.01
7727-7728	1	0.02
7728-7729	1	0.04
7729-7730	1	0.02
7730-7731	1	0.01
7731-7732	1	0.04
7732-7733	1	0.02
7733-7734	1	0.66
7769-7770	1	0.04
7770-7771	1	0.03
7771-7772	1	0.03
7773-7774	1	0.01
7774-7775	1	0.01
7775-7776	1	0.02
7776-7777	1	1.44
7777-7778	1	0.11
7778-7779	1	0.10
7779-7780	1	0.21
7780-7781	1	0.13

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 7
CASE NO. 7313
Submitted by MCCORD
Hearing Date 7-29-81

San Juan 30-5 Unit No. 27, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.01
7783-7784	1	0.03
7784-7785	1	0.03
7785-7786	1	0.09
7786-7787	1	0.02
7787-7788	1	1.01
7788-7789	1	0.05
7789-7790	1	0.06
7790-7791	1	0.05
7791-7792	1	0.31
7792-7793	1	0.03
7793-7794	1	0.02
7794-7795	1	0.01
7795-7796	1	0.05
7796-7797	1	0.18
7797-7798	1	0.61
7798-7799	1	0.34
TOTAL	65	9.07

Avg. K = $\frac{9.07}{65}$ = 0.140 md.

CHEMICAL & GEOLOGICAL LABORATORIES

Farmington

CORE ANALYSIS REPORT

Company El Paso Natural Gas Company
Well No. San Juan 30-5 #27-20
Field Wildcat
County Rio Arriba
State New Mexico

Date September 23, 1959 Lab. No.
Location Sec. 20-30N-5W
Formation Dakota
Depths 7649' - 7799'
Drilling Fluid Water Base Mud

LEGEND

C—Crack
F—Fracture
H—Horizontal
O—Open

* Permeability probably caused by existing shale interlaminations

NF—No Fracture
IS—Insufficient Sample

S—Slight
St—Stain
V—Vertical
Vu—Vugs

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY PERCENT	PERMEABILITY MILLIDARCIES		SATURATIONS		CONNATE WATER	SOLUBILITY	
				HORIZONTAL	VERTICAL	% PORE SPACE RESIDUAL OIL	% PORE SPACE TOTAL WATER		MUD ACID	15 % ACID
		Core No. 1 7649 - 7710								
1	VF	7650-51	7.7	0.01		Trace	27.8			
2	NF	7651-52	8.5	0.01		Trace	16.7			
3	VF	7652-53	6.7	0.01		Trace	12.2			
4	VF	7653-54	7.7	0.02		Trace	12.4			
5	VF	7654-55	5.2	0.01		0	21.2			
6	VF	7655-56	8.6	0.02		0	15.8			
7	VF	7658-59	8.8	0.02		Trace	12.4			
8	VHF	7661-62	10.2	0.03		0	15.2			
9	VF	7662-63	9.6	0.02		0	19.2			
10	VHF	7667-68	10.0	0.02		Trace	20.5			
11	VHF	7669-70	6.5	0.01		Trace	15.4			
12	VHF	7670-71	7.9	0.02		1.4	20.6			
13	HF	7688-89	4.9	0.01		Trace	26.1			
14	HF	7689-90	5.0	0.01		Trace	24.2			
15	HF	7690-91	5.9	0.60*		Trace	35.9			
16	HF	7691-92	3.7	0.01		Trace	94.9			
17	VHF	7692-93	7.8	0.01		Trace	54.7			
18	NF	7694-95	9.3	0.02		Trace	14.2			
19	HF	7696-97	11.4	0.25*		0	27.7			
20	NF	7697-98	6.3	0.01		0	18.6			
21	VHF	7701-02	2.6	0.01		0	62.3			
22	VHF	7707-08	2.0	0.01		0	44.5			
23	VHF	7708-09	6.1	0.02		0	16.0			
24	VHF	7709-10	5.9	0.03		Trace	33.9			

El Paso Natural Gas Company
San Juan 30—5 #27-20

Wildcat
Rio Arriba County, New Mexico

LEGEND: C—Crack; F—Fracture; H—Horizontal; O—Open; NF—No Fracture; IS—Insufficient Sample; S—Slight; St—Stain; V—Vertical; Vu—Vugs

* Permeability probably caused by existing shale interlaminations

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY % PORESPACE	PERMEABILITY MILLIDARCIES HORIZONTAL	PERMEABILITY MILLIDARCIES VERTICAL	SATURATION % PORE SPACE RESIDUAL OIL	SATURATION % PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	SOLUBILITY 15% ACID
		Core No. 2 7710 - 7719 Recovered 9'								
		No samples analyzed								
		Core No. 3 7719 - 7727 Recovered 6½'								
25	VHF	7719-20	3.8	0.01		0	30.3			
26	HF	7720-21	2.8	1.51*		0	60.7			
27	HF	7721-22	3.[illegible]	0.07		0	33.8			
28	HF	7722-23	2.4	0.25*		0	60.8			
29	HF	7723-24	4.5	0.10*		0	51.6			
30	VHF	7724-25	2.6	0.01		0	38.5			
		Core No. 4 7727 - 7738 Recovered 10'								
31	VHF	7727-28	3.0	0.02		0	16.0			
32	VHF	7728-29	3.4	0.04		0	11.8			
33	VHF	7729-30	5.4	0.02		0	11.3			
34	VHF	7730-31	1.8	0.01		0	12.2			
35	HF	7731-32	3.9	0.04		0	13.9			
36	VF	7732-33	2.5	0.02		0	12.0			
37	HF	7733-34	3.9	0.66*		0	11.0			
		Core No. 5 7738 - 7799 Recovered 61'								
38	NF	7768-69	10.1	0.04		0	39.2			
39	NF	7769-70	10.8	0.04		0	45.4	41.5		
40	NF	7770-71	10.5	0.03		0	47.1			
41	NF	7771-72	7.7	0.03		0	38.4			
-		7772-73	No sample taken							
42	NF	7773-74	5.9	0.01		Trace	49.2			
43	NF	7774-75	5.9	0.01		Trace	48.1			
44	VF	7775-76	2.5	0.02		Trace	55.2			
45	VF	7776-77	5.7	1.44*		Trace	49.6			
46	NF	7777-78	6.9	0.11		Trace	53.3	44.1		
47	NF	7778-79	7.4	0.10		0	39.3			
48	NF	7779-80	7.6	0.21		0	37.9	42.0		
49	NF	7780-81	6.2	0.13		0	40.3			
50	NF	7781-82	4.6	0.10		Trace	34.1			
51	VF	7782-83	3.8	0.01		Trace	86.8			
52	HF	7783-84	4.1	0.03		Trace	73.7			
53	NF	7784-85	4.2	0.03		Trace	68.3			
54	NF	7785-86	4.6	0.09		0	41.3			
55	NF	7786-87	5.4	0.02		0	53.0	44.7		
56	NF	7787-88	7.0	1.01*		0	42.0			
57	NF	7788-89	6.6	0.05		0	45.9	49.5		
58	NF	7789-90	6.9	0.06		0	49.6			
59	NF	7790-91	6.9	0.05		0	31.2			
60	NF	7791-92	6.4	0.31		0	26.1			
61	NF	7792-93	3.2	0.03		0	26.3			

El Paso Natural Gas Company
San Juan 30-5 #27-20

Wildcat
Rio Arriba County, New Mexico

LEGEND

C—Crack
F—Fracture
H—Horizontal
O—Open

NF—No Fracture
IS—Insufficient Sample

S—Slight
St—Stain
V—Vertical
Vu—Vugs

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY % PORESPACE	PERMEABILITY MILLIDARCIES HORIZONTAL	PERMEABILITY MILLIDARCIES VERTICAL	SATURATIONS % PORE SPACE RESIDUAL OIL	SATURATIONS % PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	SOLUBILITY 10 %. ACID
		Core No. 5 continued								
62	VF	7793-94	5.8	0.02		0	39.1			
63	VF	7794-95	4.0	0.01		0	52.3			
64	NF	7795-96	8.3	0.05		0	49.9			
65	NF	7796-97	9.5	0.18		Trace	51.7			
66	NF	7797-98	9.4	0.61		Trace	52.1			
67	NF	7798-99	9.4	0.34		Trace	53.2	46.2		

EXHIBIT NO. 8

Company: El Paso Natural Gas Company
Well: San Juan 30-5 Unit No. 28-X
Basin Dakota Field
NE/NE, Sec. 23, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8075-8076	1	0.02
8076-8077	1	0.01
8077-8078	1	0.01
8078-8079	1	0.01
8079-8080	1	0.01
8080-8081	1	0.01
8081-8082	1	0.01
8082-8083	1	0.01
8083-8084	1	0.01
8084-8085	1	0.01
8085-8086	1	0.01
8090-8091	1	0.01
8091-8092	1	0.01
8092-8093	1	0.01
8093-8094	1	0.01
8094-8095	1	0.01
8095-8096	1	0.01
8096-8096.8	.8	0.01
8116-8117	1	0.03
8117-8118	1	0.01
8118-8119	1	0.01
8119-8120	1	0.01
8120-8121	1	0.02
8121-8122	1	0.01
8122-8123	1	0.01
8123-8124	1	0.01
8124-8125	1	0.01
8125-8126	1	0.01
8126-8127	1	0.01
8127-8128	1	0.01
8128-8129	1	0.01
8129-8130	1	0.02
8130-8130.9	.9	0.01
8133-8134	1	0.01
8134-8135	1	0.01
8138-8139	1	0.01
8139-8140	1	0.01
8140-8141	1	0.01
8141-8142	1	0.01
8142-8143	1	0.01
8143-8144	1	0.01
8144-8145	1	0.01
8145-8146	1	0.01
8146-8147	1	0.01
8147-8148	1	0.65
8148-8149	1	0.01
8155-8156	1	0.01
8156-8157	1	0.01
8157-8158	1	0.01
8158-8159	1	0.01
8159-8160	1	0.01
8160-8161	1	0.05
8161-8162	1	0.02
8162-8163	1	7.2

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 8
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

San Juan 30-5 Unit No. 28-X, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8163-8164	1	0.01
8164-8165	1	0.02
8165-8166	1	0.01
8166-8167	1	0.01
8167-8168	1	0.01
8190-8191	1	2.10
8191-8192	1	0.24
8192-8193	1	0.01
8193-8194	1	0.07
8200-8201	1	0.01
8201-8202	1	0.01
8202-8203	1	0.01
8203-8204	1	0.01
8204-8205	1	0.01
8205-8206	1	0.01
8206-8207	1	0.01
8207-8208	1	0.01
8208-8209	1	0.01
8209-8210	1	0.01
8210-8211	1	0.01
8222-8223	1	0.19
8223-8224	1	0.01
8224-8225	1	0.01
8225-8226	1	0.01
8226-8227	1	0.01
8229-8230	1	0.01
8230-8231	1	0.02
8238-8239	1	0.01
8239-8240	1	0.01
8240-8241	1	0.01
8241-8242	1	0.01
8242-8243	1	0.28
8246-8247	1	0.01
8247-8248	1	0.01
TOTAL	87.7	11.66

Avg. $\frac{11.66}{87.7}$ = <u>0.133 md</u>

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

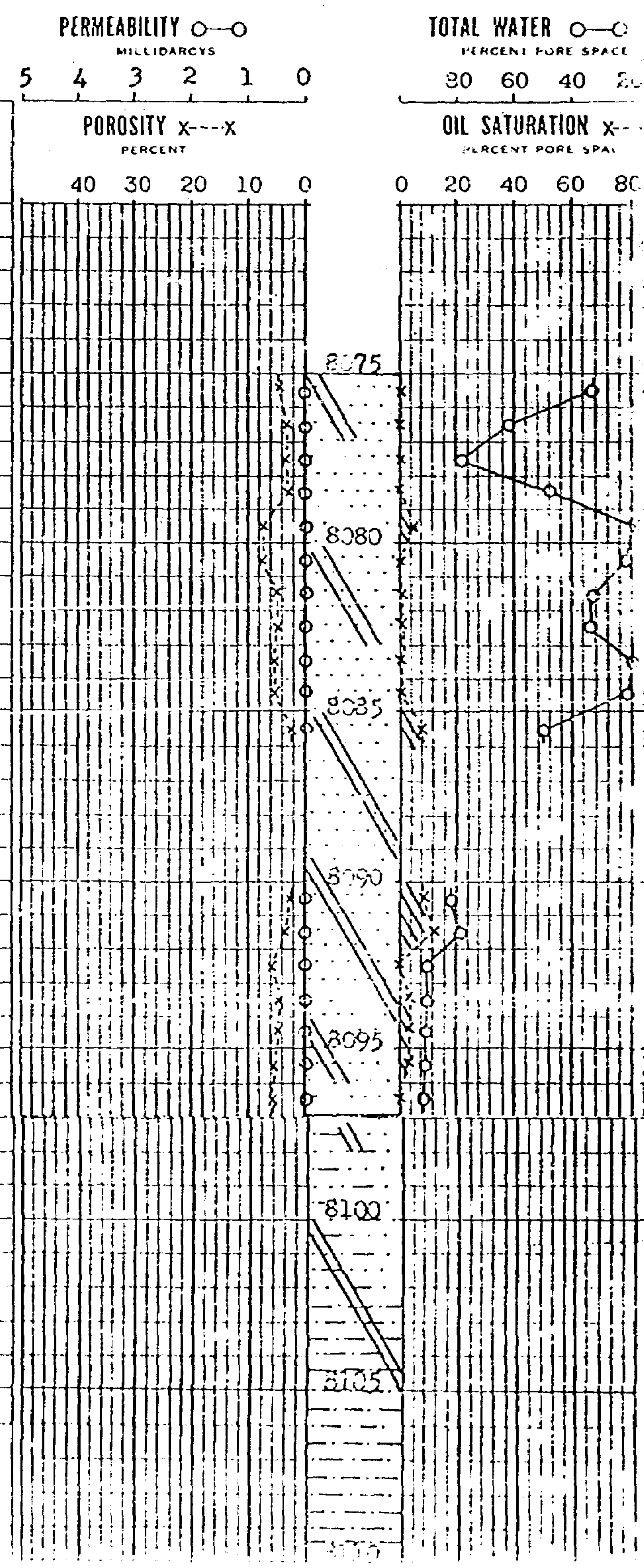
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 8/30/59 FILE NO. RP-3-1065
WELL SAN JUAN 30-5 No. 28-23 - X DATE OFF 9/8/59 ENGRS. ENGLISH
FIELD BLANCO MESA VERDE DAKOTA WILDCAT FORMATION DAKOTA ELEV. 6753' DF
COUNTY RIO ARRIBA STATE N.MEXICO DRLG. FLD. OIL EMULSION CORES DIAMOND
LOCATION SEC23 T30N R5W REMARKS SAMPLED BY CLIENT

SAND / LIMESTONE / CONGLOMERATE / CHERT / SHALE / DOLOMITE / VERTICAL FRACTURE

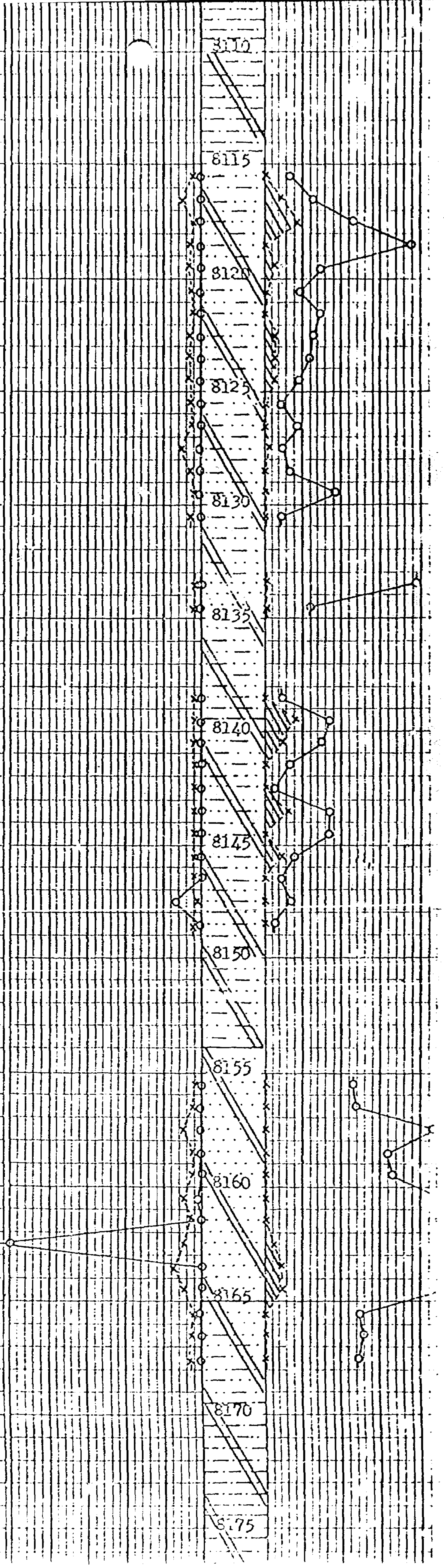
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE: OIL	RESIDUAL SATURATION % PORE SPACE: TOTAL WATER	BOYLE'S LAW POROSITY	PROD
1	8075-76	0.02	4.6	0.0	32.6		
2	76-77	<0.01	3.4	0.0	61.8		
3	77-78	<0.01	2.8	0.0	78.6		
4	78-79	<0.01	2.5	0.0	48.0		
5	79-80	<0.01	7.6	6.6	19.8		
6	80-81	<0.01	7.0	0.0	21.4		
7	81-82	<0.01	4.5	0.0	33.4		
8	82-83	<0.01	4.3	0.0	34.9		
9	83-84	<0.01	5.5	0.0	20.0		
10	84-85	<0.01	5.2	0.0	21.2		
11	85-86	<0.01	2.4	8.3	50.0		
12	8090-91	<0.01	2.2	9.1	81.8		
13	91-92	<0.01	3.7	13.5	78.4		
14	92-93	<0.01	5.7	0.0	87.7		
15	93-94	<0.01	4.2	4.8	90.5		
16	94-95	<0.01	4.3	4.7	88.4		
17	95-96	<0.01	4.8	4.2	87.5		
18	96-96.8	<0.01	5.7	0.0	91.3		

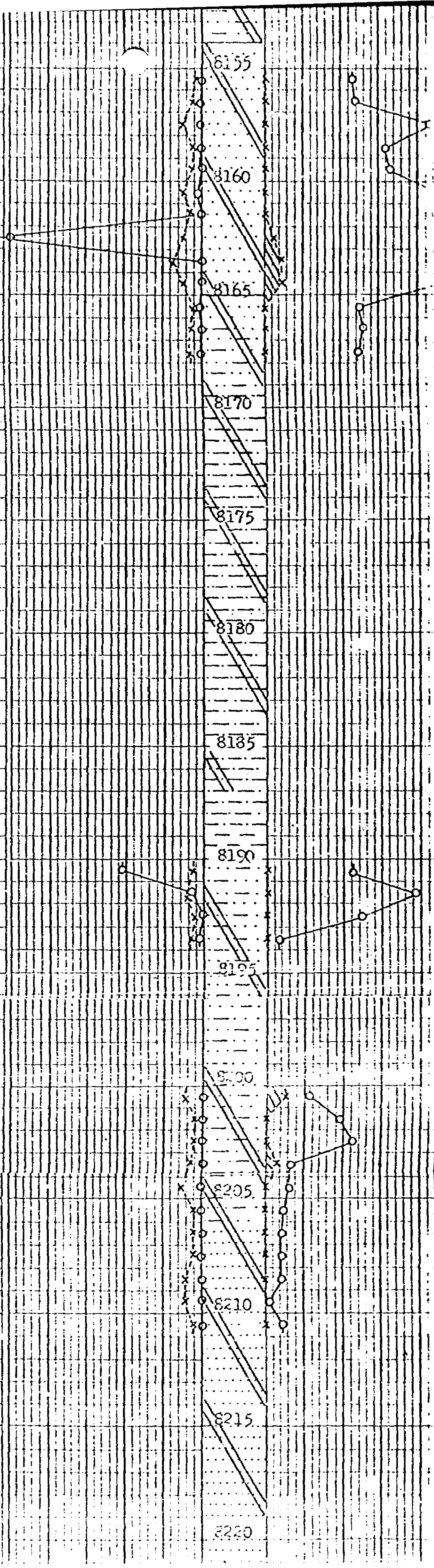
COMPLETION COREGRAPH



19	8115.5-16	0.01	2.2	0.0	86.4	1.9
20	16-17	0.03	5.0	10.0	74.0	2.9
21	17-18	<0.01	1.1	18.2	54.6	2.9
22	18-19	<0.01	2.5	0.0	24.0	3.6
23	19-20	<0.01	3.4	5.9	70.6	4.8
24	20-21	0.02	2.5	0.0	80.1	3.6
25	21-22	<0.01	2.1	0.0	71.4	3.1
26	22-23	<0.01	3.2	6.2	74.9	3.4
27	23-24	<0.01	3.4	5.9	76.5	4.3
28	24-25	<0.01	3.8	5.3	81.6	4.1
29	25-26	<0.01	3.0	0.0	90.0	3.3
30	26-27	<0.01	3.4	0.0	82.4	3.5
31	27-28	<0.01	5.8	3.4	89.7	2.4
32	28-29	<0.01	2.9	0.0	86.2	2.6
33	29-30	0.02	1.9	0.0	63.1	1.1
34	30-30.9	<0.01	3.2	0.0	90.7	4.3
35	8133-34	<0.01	1.9	0.0	21.0	2.8
36	34-35	<0.01	2.1	0.0	76.3	4.0
37	8138-39	<0.01	1.8	0.0	89.0	1.7
38	39-40	<0.01	1.2	16.7	66.6	1.0
39	40-41	<0.01	1.7	11.8	70.6	1.9
0	41-42	<0.01	1.4	0.0	85.6	2.0
1	42-43	0.01	1.8	0.0	94.4	2.2
2	43-44	<0.01	1.5	13.3	66.8	2.2
3	44-45	<0.01	0.9	0.0	66.7	1.9
4	45-46	<0.01	1.9	10.5	84.3	2.2
5	46-47	<0.01	1.3	0.0	92.4	3.3
6	47-43	0.65	1.4	0.0	85.7	5.1
7	48-49	<0.01	2.2	0.0	95.0	1.8
8	8155-56	<0.01	1.1	0.0	54.5	
9	56-57	<0.01	2.3	0.0	52.2	
0	57-58	0.01	5.4	0.0	14.8	
1	58-59	<0.01	2.2	0.0	36.3	
2	59-60	<0.01	1.8	0.0	33.3	
3	60-61	0.05	5.7	0.0	10.5	
4	61-62	0.02	3.6	0.0	11.1	
5	62-63	7.2	4.8	4.2	8.3	
6	63-64	0.01	7.2	9.7	8.5	
7	64-65	0.02	5.1	9.8	7.8	
8	65-66	<0.01	1.2	0.0	50.0	
9	66-67	<0.01	2.9	0.0	48.2	
0	67-68	<0.01	2.4	0.0	50.0	



48	8155-56	<0.01	1.1	0.0	54.5
49	56-57	<0.01	2.3	0.0	52.2
50	57-58	0.01	5.4	0.0	14.8
51	58-59	<0.01	2.2	0.0	36.3
52	59-60	<0.01	1.8	0.0	32.3
53	60-61	0.05	5.7	0.0	10.5
54	61-62	0.02	3.6	0.0	11.1
55	62-63	7.2	4.8	4.2	8.3
56	63-64	0.01	7.2	9.7	8.5
57	64-65	0.02	5.1	9.8	7.8
58	65-66	<0.01	1.2	0.0	50.0
59	66-67	<0.01	2.9	0.0	48.2
60	67-68	<0.01	2.4	0.0	50.0
1	8190-91	2.1	2.7	0.0	55.6
2	91-92	0.24	2.8	0.0	21.4
3	92-93	0.01	2.0	0.0	50.0
4	93-94	0.07	2.6	0.0	92.3
	8200-01	<0.01	4.3	11.6	76.8
	01-02	<0.01	1.3	0.0	61.5
	02-03	0.01	1.7	0.0	35.3
	03-04	<0.01	2.9	6.9	86.3
	04-05	<0.01	5.5	0.0	85.5
	05-06	<0.01	1.9	0.0	89.4
	06-07	<0.01	1.6	0.0	93.8
	07-08	<0.01	1.4	0.0	93.0
	08-09	<0.01	4.2	0.0	95.0
	09-10	<0.01	4.1	0.0	97.6
	10-11	<0.01	1.4	0.0	93.0



6	01-02	<0.01	1.3	0.0	61.5
7	02-03	0.01	1.7	0.0	[illegible]5.3
8	03-04	<0.01	2.9	6.9	86.3
9	04-05	<0.01	5.5	0.0	85.5
70	05-06	<0.01	1.9	0.0	89.4
1	06-07	<0.01	1.6	0.0	93.8
2	07-08	<0.01	1.4	0.0	93.0
3	08-09	<0.01	4.2	0.0	95.0
4	09-10	<0.01	4.1	0.0	97.6
5	10-11	<0.01	1.4	0.0	93.0
6	8222-23	0.19	3.9	0.0	97.5
7	23-24	<0.01	1.0	20.0	80.0
8	24-25	<0.01	0.6	0.0	66.6
9	25-26	0.01	1.3	0.0	15.4
0	26-27	<0.01	0.8	0.0	25.0
1	8229-30	<0.01	1.2	0.0	83.4
2	30-31	0.02	1.4	0.0	14.3
	8238-39	0.01	0.2	0.0	44.5
	39-40	<0.01	1.3	0.0	46.1
	40-41	<0.01	0.9	0.0	66.6
	41-42	0.01	1.0	0.0	40.0
	42-43	0.28	4.5	0.0	93.4
	8246-47	<0.01	3.3	6.1	88.0
	8247-48	<0.01	4.6	4.4	91.3

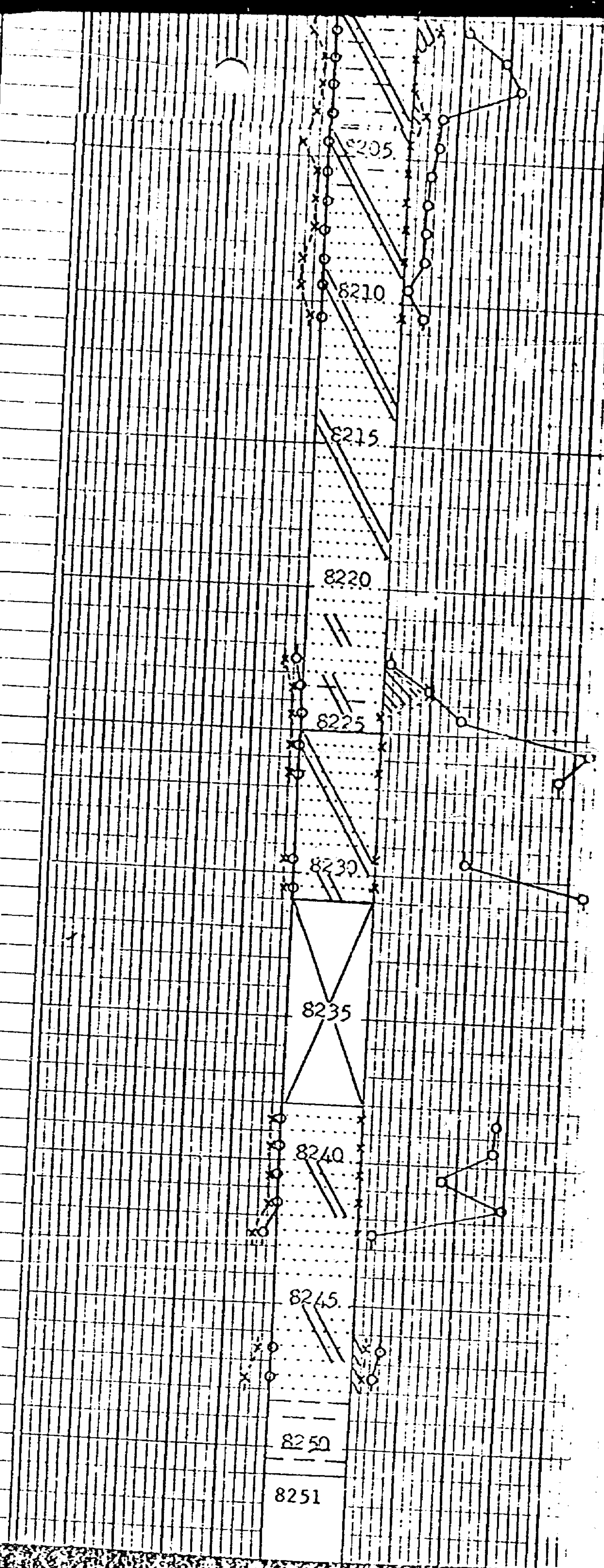


EXHIBIT NO. 9

Company: El Paso Natural Gas Company
Well: San Juan 30-6 Unit No. 31
Basin Dakota Field
SE/SW, Sec. 33, T30N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7635-7636	1	0.01
7636-7637	1	0.01
7637-7638	1	0.05
7638-7639	1	0.07
7639-7640	1	0.01
7640-7641	1	0.10
7641-7642	1	< 0.01
7642-7643	1	< 0.01
7643-7644	1	0.01
7644-7645	1	< 0.01
7645-7646	1	0.01
7646-7647	1	< 0.01
7647-7648	1	< 0.01
7716-7717	1	0.13
7717-7718	1	0.04
7718-7719	1	0.01
7719-7720	1	0.90
7720-7721	1	< 0.01
7721-7722	1	< 0.01
7722-7723	1	< 0.01
7723-7724	1	< 0.01
7724-7725	1	< 0.01
7725-7726	1	< 0.01
7746-7747	1	0.04
7751-7752	1	0.01
7752-7753	1	0.06
7753-7754	1	1.90
7754-7755	1	0.27
7755-7756	1	0.01
7756-7757	1	0.03
7757-7758	1	0.17
7758-7759	1	0.05
7759-7760	1	0.90
7760-7761	1	1.00
TOTAL	34	5.90

$$\text{Avg. } K = \frac{5.90}{34} = 0.174 \text{ md}$$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 9
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

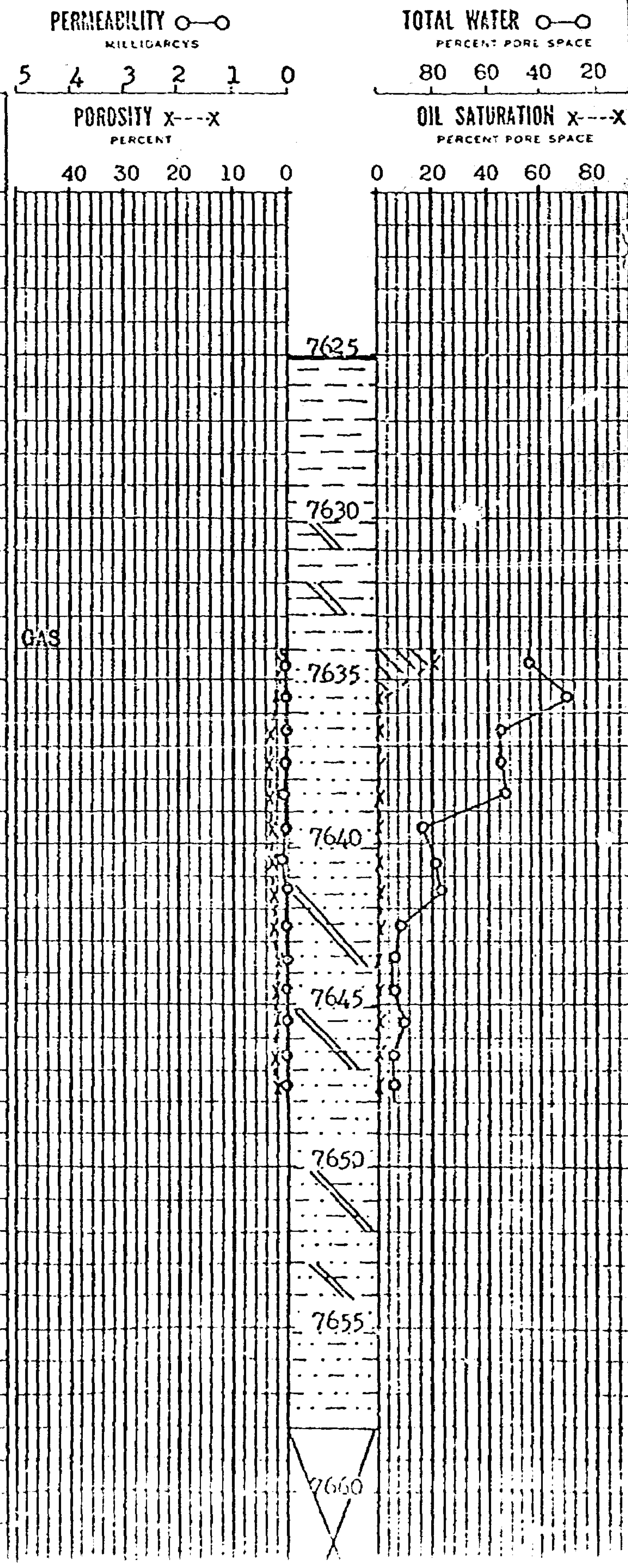
COMPANY EL PASO NATURAL GAS COMPANY	DATE ON 5/31/59	FILE NO. RP-3-997	
WELL SAN JUAN 30-6 No. 31	DATE OFF 6/8/59	ENGRS. ENGLISH	
FIELD WILDCAT	FORMATION DAKOTA	ELEV. 6364' DF	
COUNTY RIO ARRIBA STATE N.MEXICO	DRLG. FLD. AS NOTED	CORES. DIAMOND	
LOCATION SEC 33 - T30N - R6W	REMARKS SAMPLED BY CLIENT		

SAND LIMESTONE CONGLOMERATE CHERT
SHALE DOLOMITE FRACTURES

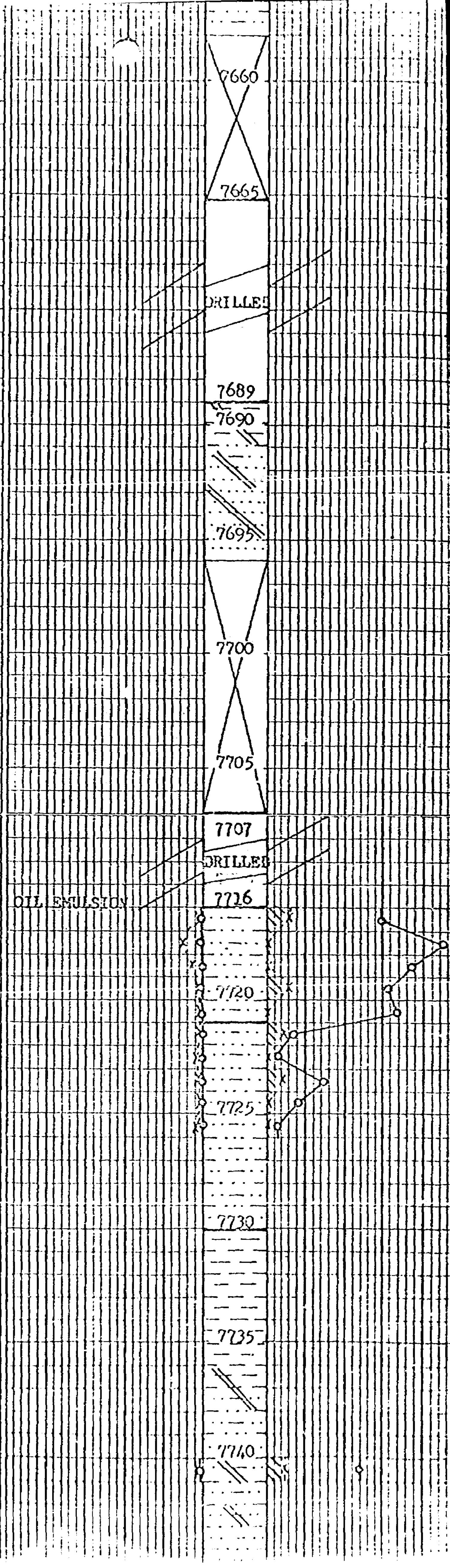
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	TOTAL WATER		PROD
1	7634-35	<0.01	0.9	22.3	44.5		
2	35-36	0.01	1.9	0.0	31.6		
3	36-37	0.01	2.5	0.0	56.1		
4	37-38	0.05	3.2	0.0	56.3		
5	38-39	0.07	3.3	0.0	54.6		
6	39-40	0.01	2.5	0.0	84.1		
7	40-41	0.10	2.9	0.0	79.3		
8	41-42	<0.01	2.6	0.0	77.0		
9	42-43	<0.01	2.1	0.0	90.6		
10	43-44	0.01	1.8	0.0	94.4		
11	44-45	<0.01	2.0	0.0	95.1		
12	45-46	0.01	1.9	0.0	89.5		
13	46-47	<0.01	2.2	0.0	95.4		
14	47-48	<0.01	1.8	0.0	94.6		

COMPLETION COREGRAPH



15	7716-17	0.13	1.5	13.3	40.0
16	17-18	0.04	5.3	0.0	11.3
17	18-19	0.01	2.3	0.0	26.5
8	19-20	0.9	1.6	12.5	37.5
9	20-21	<0.01	0.6	0.0	33.3
0	21-22	<0.01	2.0	10.0	85.0
1	22-23	<0.01	1.7	0.0	94.0
2	23-24	<0.01	2.1	9.1	71.5
3	24-25	<0.01	1.2	0 0	83.4
4	25-26	<0.01	2.2	0.0	95.5
5	7740-41 (?)	0.04	1.9	10.5	52.7



25	7740-41	0.04	1.9	10.5	52.7
26	7746-47	0.04	1.6	31.3	50.0
27	7751-52	0.01	2.4	8.3	66.7
28	52-53	0.06	7.9	0.0	30.4
29	53-54	1.9	10.2	5.0	16.8
30	54-55	0.27	7.8	6.4	15.4
31	55-56	0.01	1.6	0.0	50.0
32	56-57	0.03	4.2	4.8	23.9
33	57-58	0.17	4.8	0.0	4.2
34	58-59	0.05	0.7	0.0	28.4
35	59-60	0.9	0.6	0.0	33.3
36	60-61	1.0	1.2	0.0	16.7

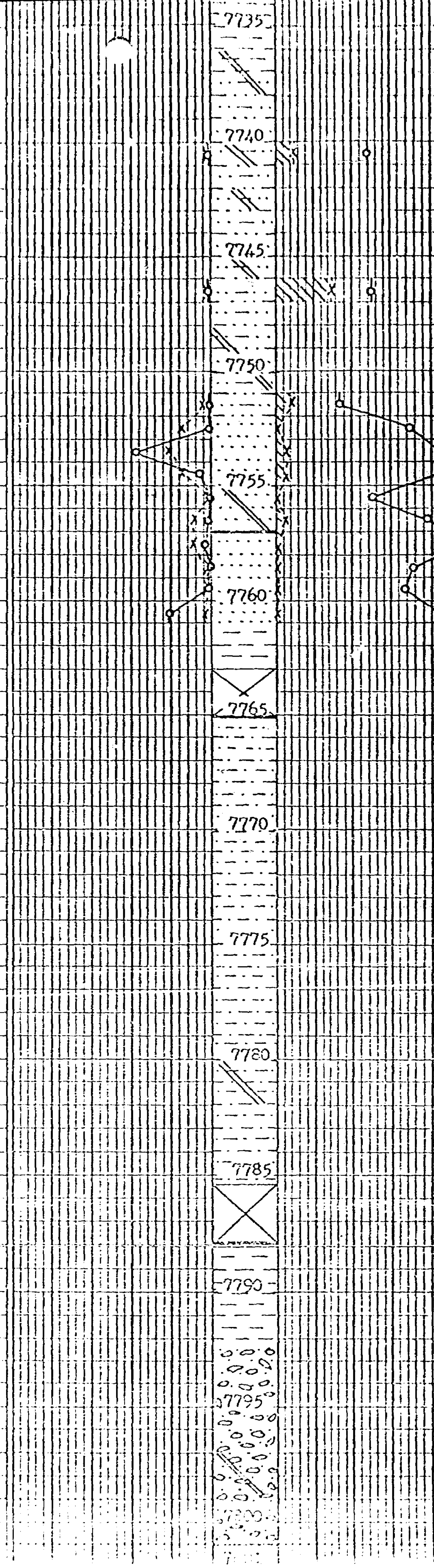


EXHIBIT NO. 10

Company: Amoco Production Company
Well: #1 Rosa Unit
Basin Dakota Field
SW/SE, Sec. 11, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7878-7879	1	0.05
7912-7914	2	0.05
7914-7916	2	0.34
7916-7923	7	0.05
7923-7928	5	0.18
7928-7930	2	0.59
7930-7931	1	0.05
7932-7936	4	0.05
TOTAL	24	

Weighted Total = 3.51 md

$$\text{Avg. } K = \frac{3.51}{24} = \underline{0.146 \text{ md}}$$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 10
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

DENVER REGION

AMOCO PRODUCTION COMPANY
CORE ANALYSIS LISTING

API WELL NUMBER - 30 039 07972 00
REGION 5 PAGE 01

API WELL NUMBER	GROUP NO.	CURRENT DATE	DATE ANALYZED
30 039 07972 00	05	81-05-05	49-05-06

	WELL OPERATOR	LSE WELL NO	LEASE NAME	LATITUDE	LONGITUDE	ELEVATION
ORIG:	STANOLIND OIL & GAS	1	ROSA UNIT	36.9082800	107.4291900	6348.0 DF
CURR:	STANOLIND OIL & GAS	1	ROSA UNIT			

SEC TWP RGE QTR QTR QTR	COUNTY STATE	FIELD CODE	ORIG COMP DATE	TOTAL DEPTH
0011 031N 006W	RIO ARRIBA, NM	00008500	49-09-10	8087.00

ANALYZING LABORATORY: STANOLIND OIL AND GAS COMPANY CITY: INPUT FORMAT 119

CORE TYPE----------DIAMOND
PRIMARY SPL TYPE---CONVENTIONAL - PLUG
SECONDARY SPL TYPE-
ANALYSIS TYPE------SUMMATION OF FLUIDS

CORE SIZE---------- INCHES
DRILLING FLUID----CHEMICAL MUD
EXTRACTION METHOD-RETORT
MULTIPLE DATA------NO

FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH
24 DKOT	7875.00						

REMARKS:

DEPTH TOP	DEPTH BASE	INT SUB	PERMEABILITY HORIZ MAX	PERMEABILITY HORIZ 90	PERMEABILITY VERTICAL	POROSITY	OIL	WATER	GAS	DENSITY	LITHOLOGY
7875.00	7879.00	<	0.05 PH			3.0 PE	2.1 PO	18.5 PW			SAND
7912.00	7914.00	<	0.05 PH			4.8 PE	0.0 PO	6.5 PW			SAND
7914.00	7916.00		0.34 PH			6.5 PE	1.7 PO	13.4 PW			SAND
7916.00	7923.00	<	0.05 PH			2.9 PE	0.0 PO	34.0 PW			SAND
7923.00	7928.00		0.18 PH			3.8 PE	15.4 PO	27.8 PW			SAND
7928.00	7930.00		0.59 PH			4.5 PE	4.3 PO	20.5 PW			SAND
7930.00	7931.00	<	0.05 PH			5.4 PE	0.0 PO	21.1 PW			SAND
7932.00	7936.00	<	0.05 PH			4.1 PE	2.8 PO	24.0 PW			SAND

BD	BULK DENSITY	PC	PLUG COMMON	PP	PLUG OF PERM SAMPLE	WE	WHOLE CORE EFFECTIVE
BG	BULK VOLUME GAS	PE	PLUG EFFECTIVE	PS	PLUG OF SAT. SAMPLE	WH	HORIZ MAX WHOLE CORE
BO	BULK VOLUME OIL	PG	PORE SPACE GAS	PV	VERTICAL PLUG	WO	WEIGHT BASE OIL
BW	BULK VOLUME WATER	PH	HORIZONTAL PLUG	PW	PORE SPACE WATER	WP	WHOLE CORE PERM SAMPLE
GD	GRAIN DENSITY	PO	PORE SPACE OIL	WC	WHOLE CORE COMMON	WR	RADIAL WHOLE CORE

WS	WHOLE CORE SAT. SAMPLE
WV	VERTICAL WHOLE CORE
WW	WEIGHT BASE WATER
9H	HORIZONTAL 90 DEGREES

EXHIBIT NO. 11

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 31-6 Unit No. 16
Basin Dakota Field
SE/SW, Sec. 33, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7904.5-7905	.5	0.02
7905-7906	1	0.02
7906-7907	1	< 0.01
7907-7908	1	< 0.01
7908-7909	1	0.06
7909-7910	1	0.01
7910-7911	1	0.01
7911-7912	1	< 0.01
7912-7913	1	< 0.01
7913-7914	1	< 0.01
7914-7915	1	< 0.01
7915-7916	1	< 0.01
7916-7917	1	< 0.01
7917-7918	1	< 0.01
7939-7940	1	< 0.01
7940-7941	1	< 0.01
7941-7942	1	0.01
7942-7943	1	0.02
7957-7958	1	< 0.01
7958-7959	1	< 0.01
7959-7960	1	0.01
7960-7961	1	0.01
7961-7962	1	0.02
7962-7963	1	0.01
7963-7964	1	0.01
7964-7965	1	0.01
7965-7966	1	0.01
7966-7967	1	0.01
7967-7968	1	0.05
7978-7979	1	0.01
7979-7980	1	< 0.01
7980-7981	1	< 0.01
7981-7982	1	0.02
7982-7983	1	0.04
7983-7984	1	0.07
7989-7990	1	< 0.01
7990-7991	1	< 0.01
7991-7992	1	0.02
8005-8006	1	0.07
8006-8007	1	0.01
8007-8008	1	0.01
8008-8009	1	< 0.01
8009-8010	1	< 0.01
8014-8015	1	0.28
8015-8016	1	0.23
8016-8017	1	0.54
8017-8018	1	0.06

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 11
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

San Juan 31-6 Unit No. 16, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8022-8023	1	< 0.01
8023-8024	1	< 0.01
8024-8025	1	< 0.01
8025-8026	1	< 0.01
8029-8030	1	0.04
8030-8031	1	0.22
8031-8032	1	0.28
8032-8033	1	0.43
8033-8034	1	0.08
8034-8035	1	0.04
8035-8036	1	0.05
8036-8037	1	0.07
8037-8038	1	< 0.01
8038-8039	1	0.14
8039-8040	1	0.35
8040-8041	1	< 0.01
TOTAL	62.5	3.60

Avg. K = $\frac{3.60}{62.5}$ = 0.058 md

CORE LAB

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

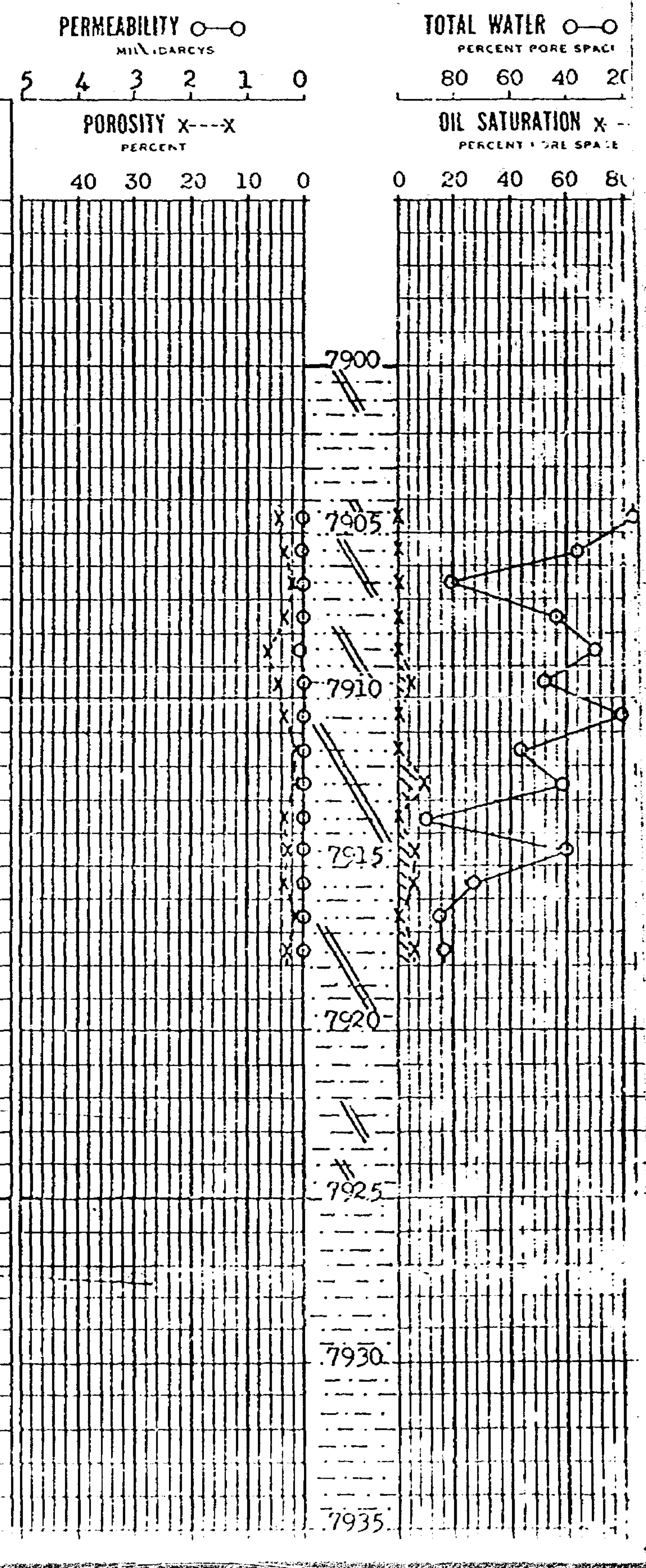
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 7/18/59 FILE NO. RP-3-1037
WELL SAN JUAN 31-6 NO. 16-33 DATE OFF 7/22/59 ENGRS. ENGLISH
FIELD WILDCAT (BLANCO MESA VERDE DAKOTA) FORMATION DAKOTA ELEV. 6499' DF
COUNTY RIO ARRIBA STATE NEW MEX. DRLG. FLD. OIL EMULSION MUD CORES DIAMOND
LOCATION SEC. 33-T31N-R6W REMARKS SAMPLED BY REPRESENTATIVE OF CLIENT.

SAND | LIMESTONE | CONGLOMERATE | CHERT
SHALE | DOLOMITE | VERTICAL FRACTURE

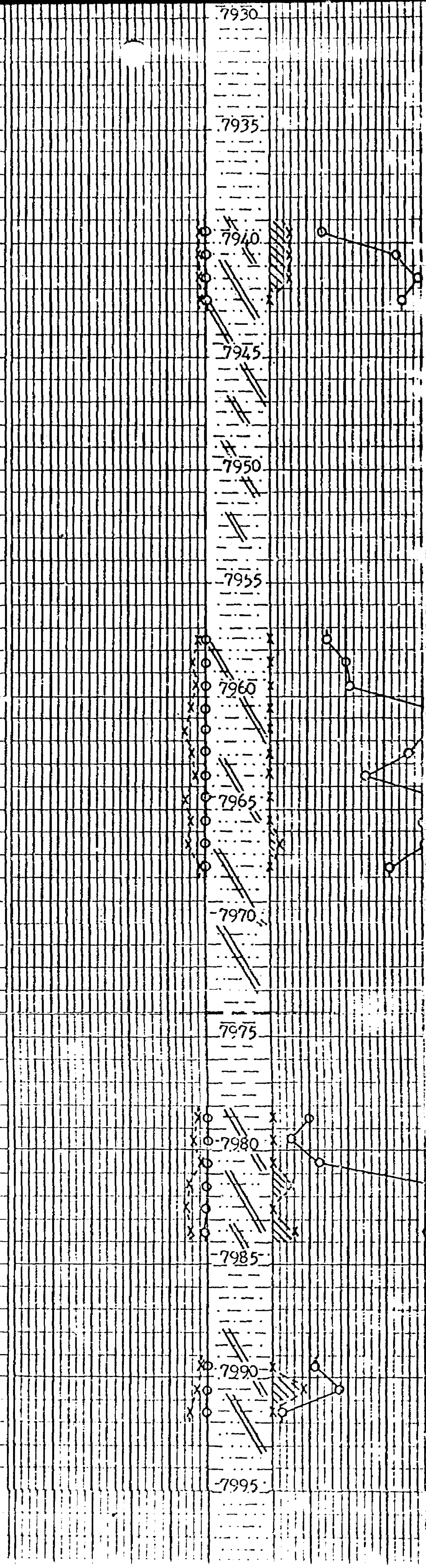
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER		PROD
1	7904½-05	0.02	4.7	0.0	17.0		
2	05-06	0.02	3.8	0.0	36.8		
3	06-07	<0.01	2.1	0.0	81.0		
4	07-08	<0.01	3.6	0.0	44.5		
5	08-09	0.06	6.3	0.0	30.4		
6	09-10	0.01	4.5	4.4	48.8		
7	10-11	0.01	3.7	0.0	21.6		
8	11-12	<0.01	1.4	0.0	57.2		
9	12-13	<0.01	1.9	10.5	42.2		
10	13-14	<0.01	3.7	0.0	89.2		
11	14-15	<0.01	3.0	6.7	40.0		
12	15-16	<0.01	3.8	5.3	73.7		
13	16-17	<0.01	1.4	0.0	85.6		
14	17-18	<0.01	3.0	6.7	83.4		

COMPLETION COREGRAPH



15	7939-40	<0.01	1.8	11.2	72.1
16	40-41	<0.01	1.8	11.2	33.3
17	41-42	0.01	1.8	11.2	22.2
18	42-43	0.02	1.3	0.0	30.8
19	7957-58	<0.01	2.0	0.0	70.0
20	58-59	<0.01	3.3	0.0	60.6
21	59-60	0.01	2.4	0.0	58.3
22	60-61	0.01	3.8	0.0	15.8
23	61-62	0.02	5.6	0.0	17.9
24	62-63	0.01	3.7	0.0	27.0
25	63-64	0.01	2.8	0.0	50.0
26	64-65	0.01	5.4	0.0	11.1
27	65-66	0.01	3.9	0.0	20.5
28	66-67	0.01	4.1	4.9	19.5
29	67-68	0.05	1.6	0.0	37.4
30	7978-79	0.01	2.6	0.0	80.7
31	79-80	<0.01	3.7	0.0	89.2
32	80-81	<0.01	1.6	0.0	75.0
33	81-82	0.02	4.6	10.9	8.7
34	82-83	0.04	5.3	0.0	7.5
35	83-84	0.07	4.2	11.9	19.0
36	7989-90	<0.01	1.8	0.0	77.7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6



36	7989-90	<0.01	1.8	0.0	[illegible].7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6
39	8005-06	0.07	1.0	0.0	40.0
40	06-07	0.01	1.2	0.0	58.2
41	07-08	0.01	0.9	0.0	66.6
42	08-09	<0.01	1.8	0.0	94.4
43	09-10	<0.01	1.8	0.0	94.4
44	8012-13	<0.01	3.6	5.5	80.6
45	8014-15	0.28	6.9	0.0	14.5
46	15-16	0.23	9.1	0.0	19.8
47	16-17	0.54	6.7	0.0	32.8
48	17-18	0.06	4.0	0.0	32.5
49	8022-23	<0.01	2.9	6.9	89.8
50	23-24	<0.01	3.2	15.6	81.3
51	24-25	<0.01	3.6	0.0	94.5
52	25-26	<0.01	5.2	0.0	90.4
53	8029-30	0.04	2.7	7.4	14.8
54	30-31	0.22	4.1	0.0	14.6
55	31-32	0.23	3.8	5.3	44.7
56	32-33	0.43	5.0	0.0	12.0
57	33-34	0.08	4.8	10.4	35.4
58	34-35	0.04	5.0	0.0	20.0
59	35-36	0.05	7.7	6.5	26.0
60	36-37	0.07	8.3	2.4	19.3
61	37-38	<0.01	7.6	2.6	21.1
62	38-39	0.14	6.1	3.3	26.3
63	39-40	0.35	6.2	0.0	19.3
64	8040-41	<0.01	7.4	0.0	21.6

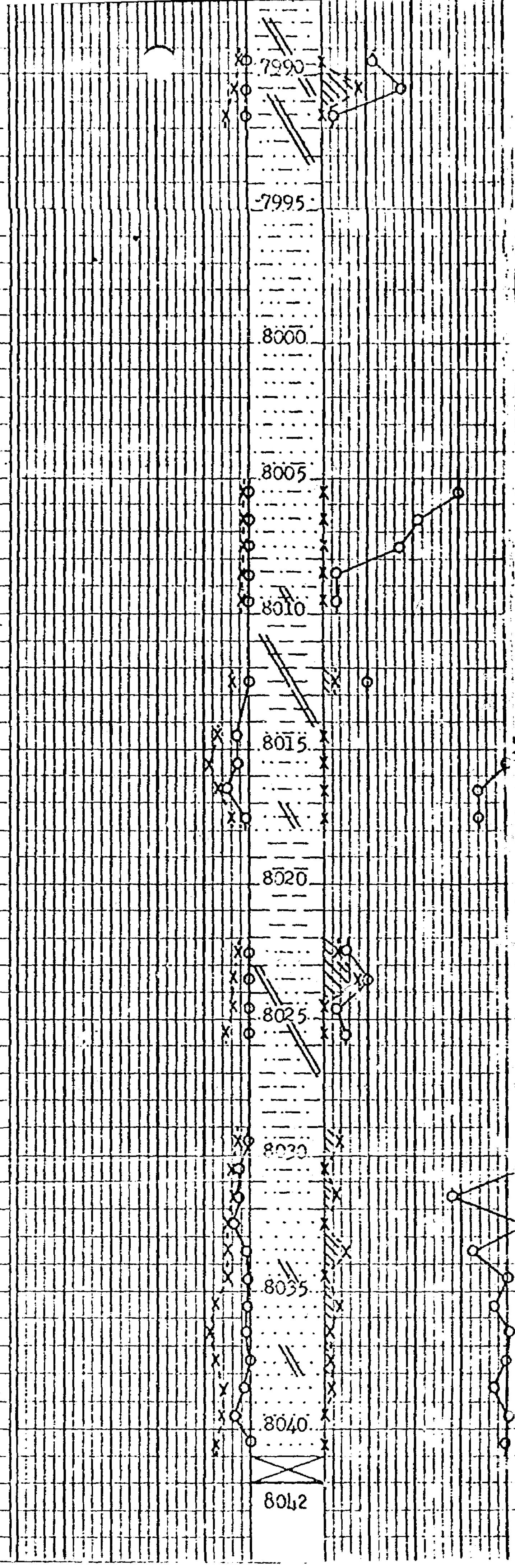


EXHIBIT NO. 12

Company: Blackwood & Nichols, Ltd.
Well: Northeast Blanco Unit No. 1
Basin Dakota Field
SE/NE, Sec. 27, T31N, R7W
San Juan County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7831-7832	1	0.01
7832-7833	1	0.01
7833-7834	1	0.01
7834-7835	1	0.01
7835-7836	1	0.01
7836-7837	1	0.01
7837-7838	1	0.01
7838-7839	1	0.01
7839-7840	1	0.01
7840-7841	1	0.01
7841-7842	1	0.01
7842-7843	1	0.01
7843-7844	1	1.50
TOTAL	13	1.62

$$\text{Avg. } K = \frac{1.62}{13} = \underline{0.125 \text{ md}}$$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 12
CASE NO. 7313
Submitted by MCCORD
Hearing Date 7-29-81

CORE DESCRIPTIONS

CORE #1 6990-7039. Recovered 21' blk. shale, bottom 6' sli sandy.

CORE #2 7039-7042. Core jammed in bbl. Recovered 2' blk shale.

CORE #3 7042-7045½. Core jammed in bbl. Recovered 3' blk shale.

CORE #4 7800-7830. Recovered 25 1/2'.

1. shale, gry-blk, platy, sli sandy, micaceous, tr coal
2. sand, gry, vfg, calc, sli silty, scattered mica., dnse
3. shale, blk, micaceous, w/scattered sand lenses, 15% sand
4. sand, gry, vfg, calc, very silty, shale stringers, abdt mica, dnse, tite.
5. same
6. same, 20% blk shale
7. shale and sand in alternating layers, predominately shale
8. shale, blk, sli sandy, calc, micaceous
9. same, w/pearly pelecypod frags
10. same
11. same
12. same
13. same
14. same, concentric fractures parallel to bedding
15. limestone, buff-brn, dnse, silic, crypto-xln, horizontal fractures
16. shale, blk, sli sandy, micaceous
17. same, concentric fractures parallel to bedding
18. same, no fractures
19. shale and sand in alternating layers, predom. shale
20. shale and sand in alternating layers, predom. sand
21. sand, gry-wh, fg, hard, dnse, scattered intergranular poro
22. same, sli silty, w/horizontal fractures
23. same, shaley (40%), micaceous
24. shale, blk, micaceous (75%); sand (25%)
25. sand, gry, fg, hard, micaceous, w/abdt pyrite
26. same (60%); shale (40%)

CORE #5 7830-7831. No recovery.

CORE #6 7831-7844. Full recovery.

1. sand, gry-wh, fg, hard horiz. frac, tr fair intergranular poro
2. same, w/thin shale partings, tr fair poro
3. same, no frac, tr fair poro
4. same, sli silty, tr fair poro
5. same
6. same, fair poro
7. same, tr fair poro
8. same
9. same

10. same
11. same, w/thin shale partings
12. same, tr fair poro
13. same, shale (20%), tr poro

CORE #7 7844-7844. Full recovery.
1. sand, gry-wh, fg, hard, tr intergranular poro
2. same, w/scat shale partings and horiz frac
3. same
4. same

---o---

ABBREVIATIONS USED IN SAMPLE & CORE DESCRIPTION

A - angular
abdt - abundant
bent - bentonite (itic)
blk - black
brn - brown
calc - calcareous
dnse - dense
fg - fine grained
foss - fossiliferous
frac - fractured
frag - fragment(s)
fx - finely crystalline
glau - glauconite(ic)
grn - green
gry - gray
horiz - horizontal
IGR - intergranular
incl - inclusions
lg - large grained
ls - limestone
mg - medium grained
poro - porosity
pyr - pyrite
qtzitic - quartzitic
R - rounded
SA - subangular
scat - scattered
sdy - sandy
sh - shale
silic - siliceous
sli - slight
SR - subrounded
ss - sandstone
tr - trace
V - very
vert - vertical
wh - white
xln - crystalline

CORE ANALYSIS DATA

CORE #6 - 7831-7844

SAMPLE NO.	DEPTH	PERMEABILITY MILLIDARCYS	NET POROSITY %	TOTAL POROSITY %
1	7832	0.01	4.20	4.65
2	7833	0.01	2.75	3.70
3	7834	0.01	4.10	4.42
4	7835	0.01	1.17	2.08
5	7836	0.01	1.97	2.81
6	7837	0.01	2.28	3.50
7	7838	0.01	3.08	7.80
8	7839	0.01	8.50	9.30
9	7840	0.01	7.20	7.90
10	7841	0.01	2.76	3.96
11	7842	0.01	2.65	2.33
12	7843	0.01	1.53	3.80
13	7844	1.50*	2.35	3.60

* This plug was taken across a natural, well bonded horizontal fracture.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 13
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

EXHIBIT NO. 13

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

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.[5] 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,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

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

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.

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 staniless 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 realistic 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-

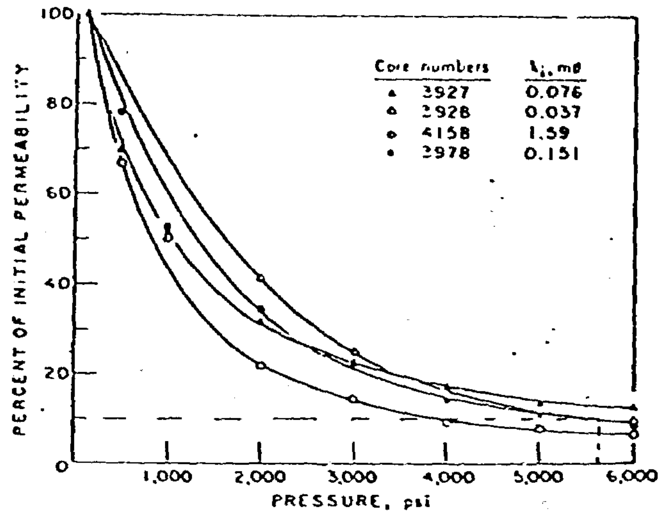


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

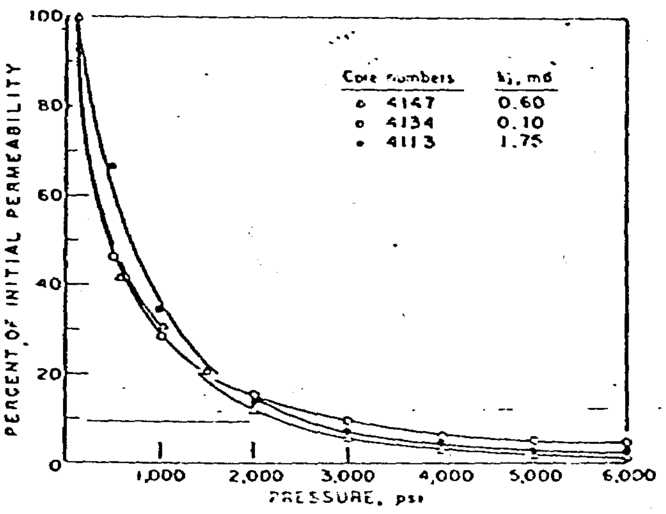


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

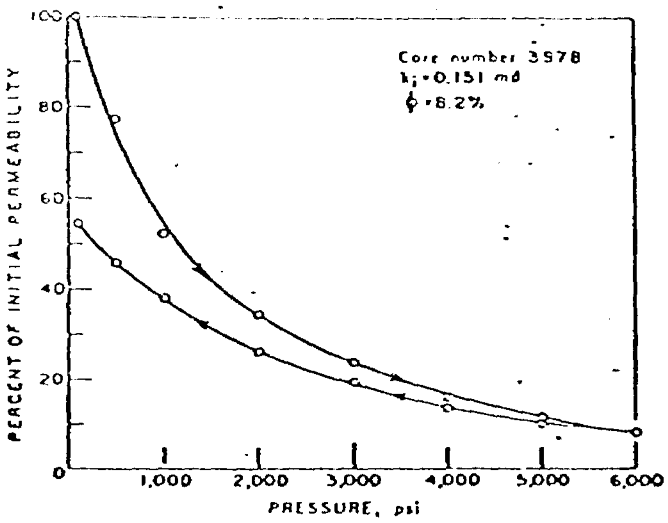


Fig. 3—Hysteresis effect at decreasing confining pressures.

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	0.016
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. 5 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

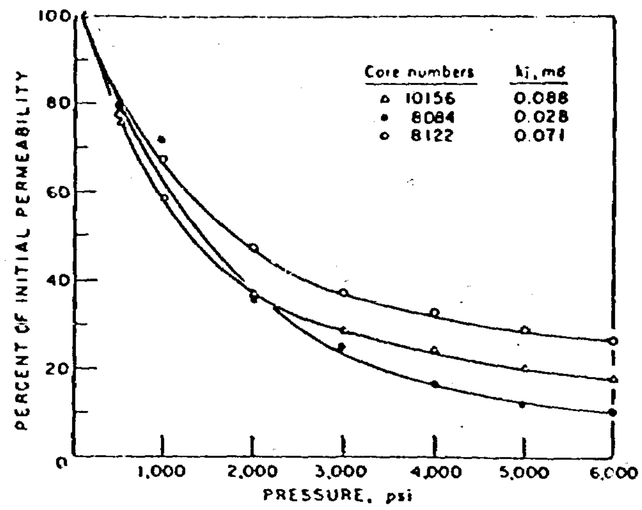


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

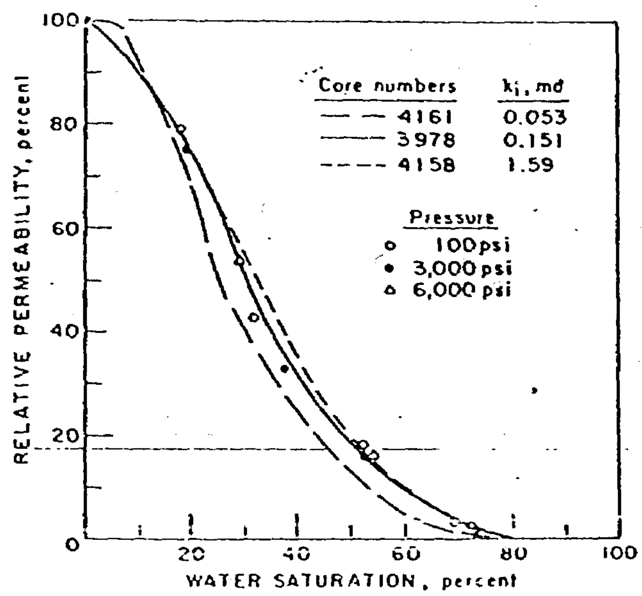


Fig. 5—Relative gas permeability of Gasbuggy cores.

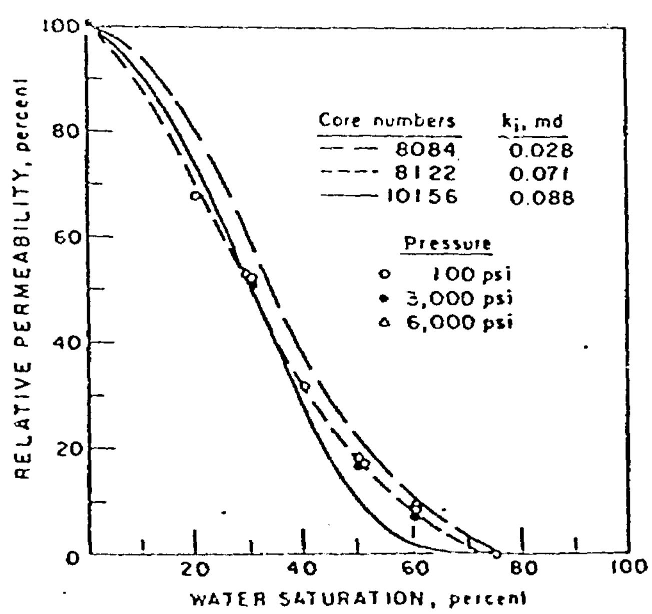


Fig. 6—Relative gas permeability of Wagon Wheel cores.

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.

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.

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.

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EXHIBIT NO. 14

DETERMINATION OF IN SITU FORMATION PERMEABILITY FROM LABORATORY CORE ANALYSIS DATA IN THE ROSA TIGHT GAS AREA

The relationship needed to determine in situ permeability from core analysis data is published in a technical paper by Rex D. Thomas and Don C. Ward entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", which is presented as Exhibit No. 13. The authors' studies involved taking routine laboratory air permeability measurements at the normal 100 psi or less external pressures. To simulate the effect of in situ conditions, these permeability measurements were then made at external pressures ranging from 500 to 6000 psi. The results of these tests were then plotted on a graph of Percent of Initial Permeability (ratio of permeability at 100 psi to a permeability at a higher pressure) vs. Pressure.

Figure 1, on Page 121, of Exhibit No. 13, is one such graph which presents results of tests run on cores taken from the Pictured Cliffs Formation. These cores were taken from Project Gasbuggy, located in Rio Arriba County, New Mexico. Cores from the Pictured Cliffs Formation and the Dakota Formation can be expected to provide similar results due to the low permeability characteristics of both sands.

The characteristics of core 3978, presented in Figure 1, can be used to represent the core data from the Rosa Tight Gas Area. The average laboratory air permeability from the Rosa Area was 0.124 millidarcy compared to an initial laboratory core permeability for core 3978 of 0.151 millidarcy. The confining pressure due to overburden at a depth of 7950 feet in the Rosa Area is approximately 5600 psi.

Entering the graph in Figure 1 at 5600 psi results in an 90% permeability reduction between laboratory determined permeability values and in situ permeability in the Rosa Area. Applying this 90% reduction to the average laboratory permeability of 0.124 millidarcy results in an average in situ permeability of 0.012 millidarcy for the Rosa Tight Gas Area.

The water present in the reservoir also causes the in situ permeability to be less than laboratory permeability as discussed in Exhibit No. 13. However, this correction will not be used in this case.

SUMMARY OF PERMEABILITY DATA

EXHIBIT NO. 15

	WELL	SAMPLE FOOTAGE TOTAL (ft.)	LABORATORY PERMEABILITY TOTAL (md)
1.	Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	65.0	9.07
2.	El Paso Natural Gas Co. San Juan 30-5 Unit No. 28-X	87.7	11.66
3.	El Paso Natural Gas Co. San Juan 30-6 Unit No. 31	34.0	5.90
4.	Amoco Production Co. Rosa Unit No. 1	24.0	3.51
5.	Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	62.5	3.60
6.	Blackwood and Nichols Ltd. Northeast Blanco Unit No. 1	13.0	1.62
	TOTAL:	286.2	35.36

Average laboratory permeability = $\frac{35.36}{286.2}$ = 0.124 md

Average in-situ permeability (10% of laboratory) = 0.012 md

EXHIBIT NO. 16

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 16
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

ROSA TIGHT GAS AREA

Natural Production Tests
(Pitot Tube)

	OPERATOR	WELL	LOCATION	NATURAL PRODUCTION TEST DEPTH	DAKOTA DEPTH	PRODUCTION RATE NATURAL (MCFPD)	PRODUCTION RATE AFTER FRAC (MCFPD)
1.	El Paso Natural Gas Co.	San Juan 30-4 Unit No. 39	SENW 18 30-4	8615	8425	527	2506
2.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 39	SWNE 7 30-5	7822	7686	161	1703
3.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 37	NESW 8 30-5	7870	7688	666	3944
4.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 49	SWSW 9 30-5	7780	7683	TSTM	855
5.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 73	NWNE 10 30-5	8035	7919	338	2635
6.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 72	SWSW 10 30-5	7905	7790	338	2456
7.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 53	NESW 16 30-5	7820	7685	264	1209
8.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 47	NWSW 17 30-5	7930	7794	2174	1610*
9.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 38	SWNE 18 30-5	7891	7667	128	2035
10.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 48	NWNE 20 30-5	7870	7790	370	3691
11.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 38	NENW 2 30-6	7970	7832	241	2828
12.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 36	NENE 27 31-6	7890	7806	TSTM	2557
13.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 35	NENE 35 31-6	8080	7908	338	2643
14.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 31	SESE 35 31-6	7928	7796	370	3770
			14 WELL AVERAGE			423	2460
			13 WELL AVERAGE (Excluding Well No. 8)			288	2525

Natural Production Rate Limit for Tight Gas @ 7950 ft. is 336 MCFPD.

*Note after frac production rate is less than natural production rate.

EXHIBIT NO. 17

FOUR CORNERS GAS PRODUCERS
Rosa Tight Gas Area
Basin Dakota Field

Calculation of Initial Pre-Stimulation Flow Rates Using Darcy's Law

Darcy's Law: $$Qg = .703\ k\ h \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw}$$

where:

- Qg = gas flow rate - standard cubic feet per day
- k = permeability of formation - used average in situ value of 0.012 md from core data
- h = net pay - average of 42 ft. for wells completed in the Rosa Tight Gas Area.
- Pe = bottom hole pressure at drainage radius re - average of 3330 psi. from 7 day buildup tests run in the Rosa Tight Gas Area
- Pwf = flowing bottom hole pressure - assumed to be equal to atmospheric pressure at wellbore conditions, to determine maximum flowrate (14.6 psi)
- Ug = average gas viscosity - calculated to be 0.020cp
- T = bottom hole temperature - calculated to be $667^{o}R$
- Z = average gas compressibility factor - calculated to be 0.88
- re = drainage radius for 160 acre spacing - 1320 ft.
- rw = wellvore radius - .17 ft.
- gg = gas gravity - .7 - used for calculation of Ug and Z
- Pc = pseudo critical pressure - 668 psi. - used for calculation of Ug and Z
- Tc = pseudo critical temperature - 392^{o} R - used for calculation of Ug and Z

$$Qg = .703\ (0.012)\ (42) \frac{(3330^2 - 14.6^2)}{(0.020)\ (667)\ (0.88)\ \ln\ (.61\ 1320/.17)}$$

Qg = 39,546 SCFGPD = <u>39.5 MCFGPD</u>

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 17
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
LARRY KEHOE
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Post Office Box 2208
Santa Fe, New Mexico

Re: CASE NO. 7317
ORDER NO. R-6883-A

Applicant:

Four Corners Gas Producers Association

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 Tom Kellahin, Gary Paulson, Larry Paine

APPLICATION OF

FOUR CORNERS GAS PRODUCERS ASSOCIATION

FOR DESIGNATION OF THE ROSA AREA OF THE BASIN DAKOTA FIELD

AS A TIGHT GAS FORMATION

RIO ARRIBA AND SAN JUAN COUNTIES, NEW MEXICO

Case No. 7313 July 29, 1981

Prepared by:

KEVIN H. McCORD
Petroleum Engineer

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION
FOR DESIGNATION OF THE ROSA AREA OF THE
BASIN DAKOTA FIELD AS A TIGHT FORMATION,
RIO ARRIBA AND SAN JUAN COUNTIES,
NEW MEXICO

The Four Corners Gas Producers Association is applying for a portion of the Basin Dakota gas field to be designated as a tight formation under Section 107 of the Natural Gas Policy Act of 1978. The proposed Rosa Tight Gas Area is located in the northeastern portion of the San Juan Basin. The area is approximately 25 miles northeast of the town of Bloomfield in northwestern New Mexico and covers portions of Rio Arriba and San Juan counties.

Exhibit No. 1 displays the Rosa Tight Gas Area on a map of the Dakota reservoir in the San Juan Basin. The Rosa Area includes approximately 270,260 acres, described as follows:

1.	T30N-R2W	Sections 1 through 36:	All
2.	T30N-R3W	Sections 1 through 36:	All
3.	T30N-R4W	Sections 1 through 36:	All
4.	T30N-R5W	Sections 1 through 36:	All
5.	T30N-R6W	Sections 1 through 36:	All
6.	T30N-R7W	Sections 1 through 36:	All
7.	T31N-R2W	Sections 1 through 36:	All
8.	T31N-R3W	Sections 1 through 36:	All
9.	T31N-R4W	Sections 1 through 36:	All
10.	T31N-R5W	Sections 1 through 36:	All
11.	T31N-R6W	Sections 1 through 36:	All
12.	T31N-R7W	Sections 1 through 36:	All

The Dakota formation in the Rosa Area meets the criteria established in Section 107 of the Natural Gas Policy Act of 1978 to be designated a tight gas formation in that (1) the estimated average in situ gas permeability throughout the pay section is expected to be 0.1 millidarcy or less, (2) the stabilized production rates, without stimulation, at atmospheric pressure of these gas wells are not expected to exceed

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 18
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

the maximum allowable production rate of 336 MCFPD for an average depth of 7950 feet to the top of the Dakota formation in this area, and (3) no well drilled into the Dakota formation in this area is expected to produce more than five barrels of crude oil per day prior to stimulation.

Exhibit No. 2 is a Dakota formation completion and production map of the proposed Rosa Tight Gas Area. The production figures presented for each producing well are initial potential, date of initial potential, average daily production for 1980, and January 1, 1981 cumulative production of gas and oil. Exhibit No. 2 also presents completion and production data from wells surrounding the proposed tight gas area. The Rosa Tight Gas Area contains 53 producing Dakota formation gas wells, while 14 wells in this area are abandoned in the Dakota at this time. A list of these wells and their production figures is presented as Exhibit No. 3. Examination of these figures indicate that these Dakota wells have not produced great quantities of natural gas, suggesting that low permeability reservoir rock could be present in the area.

Exhibit No. 4 is a type log of a Dakota well found in the Rosa Tight Gas Area. This log is from the Northwest Pipeline Corporation Rosa Unit No. 68 well, found in section 17, T31N, R5W. This well is in the north central section of the Rosa Tight Gas Area. The type log shows the entire Greenhorn and Dakota formations and part of the Mancos and Morrison formations. The type log shown is in a part of the Rosa Tight Gas Area which has exhibited better producing characteristics than the remainder of the area. Wells in remaining sections of the Rosa Area would be expected to have the same or poorer log characteristics than this type log.

The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 400 feet below the base of the Greenhorn. The formations covered in this 400 feet are the Graneros Shale, Dakota Sandstone, and Morrison formations. The Dakota formation is productive in this area, while the Morrison formation is generally water bearing. Sands in the Graneros Shale are not adequately developed in this area to be productive.

The Dakota formation has an average depth of 7950 feet in the Rosa Area, and has approximately 250 feet of gross thickness. The Dakota sandstone formation is Late Cretaceous in age with deposition occurring under both

marine and nonmarine conditions. The Dakota sandstone is the basal sequence of the southwesterly transgressing Cretaceous Sea.

The Upper Dakota sand consists of barrier beach deposits about 40 to 60 feet thick, composed of fine grained, quartz-rich sandstones characterized by an increase in grain size upward and low angle crossbedding. The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones, and sandstones. This unit represented a lagoonal type environment. The basal Dakota was deposited by a system of meandering streams creating deposits of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstones. The basal unit of Cretaceous strata in the Four Corners Area is the Burro Canyon formation. This formation was deposited in a braided stream system and is sometimes considered part of the Dakota formation. An unconformity exists between the Burro Canyon formation and the Morrison formation represented by a sharp erosional contact between the two formations.

Overall, the Dakota sand has a porosity range from 1/2 to 11-1/2% in the Rosa Area, with the average pay porosity being 4%. Silt and clay sized matrix material is present throughout the Dakota sand sequence and represents a significant portion of the bulk rock composition. This matrix material reduces the effective permeability of the formation, making it difficult to produce.

Exhibit No. 5 and 6 are log cross sections through the Rosa Area showing the continuity of the Dakota formation using the base of the Greenhorn formation for a datum line.

Permeability

The Dakota formation in the San Juan Basin is dependent on stimulation techniques to be commercially productive due to the low permeability of the reservoir rock. The Dakota in situ permeability in the Rosa Tight Gas Area is found to be less than the 0.1 millidarcy permeability cutoff used for tight gas determination. The in situ permeability for this area was calculated using data from six Dakota core analysis and was averaged to be 0.012 millidarcy.

Exhibit Nos. 7 through 12 present core analysis data used to determine the average laboratory permeability to air for Dakota formation pay zones in this area. The exhibits contain the actual core analysis reports plus summary

tables showing the analysis of cores taken from only the productive portion of the Dakota formation for each well. The cored intervals chosen for permeability averaging were determined by log examination of the interval cored for each well. Only cored intervals of sand with more than 10 ohms resistivity appearing on the Induction Resistivity log of the well were used for permeability averaging. This 10 ohms resistivity cutoff represents the average resistivity shown by the shale sections on the logs, Values less than this cutoff were not considered to be pay zones. The average laboratory permeability to air determined for the Rosa Area in this manner was 0.124 millidarcy. The actual in situ permeability of the formation is less than this laboratory determined value mainly due to the confining pressures found in the Basin Dakota reservoir.

Exhibit No. 13 presents a technical paper intitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores" written by Rex D. Thomas and Don C. Ward of the U. S. Bureau of Mines. This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs. Exhibit No. 14 explains how in situ permeability is calculated from the core analysis using the technical paper presented.

Exhibit 15 is a summary of all laboratory core analysis results, for the Rosa Tight Gas Area. An average in situ permeability value of 0.012 millidarcy was calculated from the average laboratory permeability value of 0.124 md for the Rosa Area. This in situ permeability value is well below the 0.1 millidarcy tight gas cutoff. These permeability measurements substantiate that the Dakota formation is very tight in this area and must be stimulated to obtain commercial gas production.

Stabilized Unstimulated Gas Production Rate

Obtaining stabilized unstimulated gas production rates for Dakota wells is not a standard procedure used by companies when completing their wells in the San Juan Basin. Past experience has shown that these low permeability Dakota wells must be stimulated to obtain commercial production. However, some wells drilled in the Rosa Tight Gas Area were drilled with gas as a circulation medium through the Dakota formation. This drilling procedure enables unstimulated natural gas from the Dakota formation to rise to the

surface while drilling the well..

Unstimulated natural production tests can be taken while drilling with natural gas when the gas used for circulation is shut off and the pipe rams closed on the blowout preventer stack. This enables the injected gas to blow down through a bleedoff line to the reserve pit. After injection gas has had sufficient time to return to the surface, any further gas production through this line should be unstimulated gas production from the well. A gas measuring device, such as a pitot tube, placed in the center of the natural gas production stream is used to measure the natural gas flow rate from the well. A pitot tube measures the impact pressure of the gas flow rate which is used to determine the velocity of the gas. This gas velocity, combined with the known area of the blowoff line is used to calculate the flowrate of gas through the line. Natural unstimulated gas production tests performed in this manner were found for 14 wells in the Rosa Area.

The results of these unstimulated gas production tests are presented in Exhibit 16. These gas flowrates range from rates too small to measure to 2174 MCF of natural gas per day. The average unstimulated gas production rate is 423 MCFGPD. This value is larger than the 336 MCFGPD limit for tight gas at an average depth of 7950 feet. On an individual well basis, 6 wells meet the unstimulated natural production requirement, with 3 wells just at the limit, and 5 wells being over the 336 MCFGPD limit.

Testing natural gas wells in this manner is not very accurate, but it can give the tester some idea if a well will be gas productive or not. The exact nature of these tests have many factors which leave their results questionable:

(1) The Mesa Verde formation is also productive in the Rosa Tight gas area. While the Dakota formation is open to flow to the surface during the natural flow test, the Mesa Verde can also be producing at the same time. There is no way to seperate the production from each zone using a natural production test conducted in this manner.

(2) The length of these unstimulated production tests are not long enough to establish a stabilized production rate. This length of test can by no means be considered to be a stabilized production test of the well's productivity.

(3) The natural gas injected into the well for circulating purposes can also cause erroneous results if this gas is still returning to the surface while the test is being taken.

It is reasonable to assume that the three test uncertainties presented above could all contribute to make unstimulated production tests performed in this manner report erroneously high production rates. This assumption is

supported by well production data presented in Exhibit 16.

The well listed as number 8, the Northwest Pipeline Corporation San Juan 30-5 Unit No. 47 well shows an unstimulated natural gas production rate of 2174 MCFGPD. After fracturing, the initial production for this well was 1610 MCFGPD. The initial potential for a well is calculated from a 3 hour flow test following a 7 day pressure buildup, which is a more controlled and accurate test than the pitot tube test. This, combined with the fact that an after frac production test should definitely not be lower than the unstimulated production test, indicates the unstimulated production test is probably in error.

Exhibit 16 also presents a 13 well average unstimulated production rate which excludes the erroneous rate found for the San Juan 30-5 Unit No. 47 well. This 13 well average rate is 288 MCFGPD, which is below the 336 MCFGPD rate limit for tight gas determination in the Rosa Area. Due to the uncertain nature of the unstimulated production rate testing process, this 288 MCFGPD production rate, while below tight gas guidelines, is still thought to be higher than the actual average unstimulated gas production rate for the area.

In order to test the validity of this natural production figure, Darcy's Law was used to calculate an unstimulated gas flow rate using the average in situ permeability value of 0.012 millidarcy calculated for the Dakota formation in this area from core analysis study. Exhibit No. 17 presents this calculation and shows that an initial unstimulated gas flow rate of 39.5 MCFGPD is associated with the average in situ permeability of 0.012 millidarcy for the Rosa Area.

The calculated unstimulated gas production rate and the average actual unstimulated gas production rate (excluding the erroneous production rate mentioned previously) are both less than the 336 MCFGPD limit for a tight gas reservoir in the Rosa Area. As a result of these calculations, the unstimulated natural gas production rate from the Dakota formation in the Rosa Area is not expected to exceed 336 MCF of gas per day.

Stabilized Unstimulated Oil Production Rate

The Natural gas produced from the Rosa Tight Gas area is virtually dry gas, having very little, if any, oil or condensate production associated with it. Exhibits No. 2 and 3 show that only one well, the Northwest Pipeline

Corporation Rosa Unit No. 56, has reported any oil production associated with its' gas production. This well has only produced 26 barrels of oil since 1976. These dry gas production figures indicate that no well drilled in the Rosa Tight Gas Area is expected to produce. without stimulation, more than five barrels of crude oil per day.

Fresh Water Protection

Existing State and Federal regulations will assure that development of the Dakota formation will not adversely affect or impair any fresh water acquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Regulations require that casing programs be designed to seal off potential water bearing formations from oil and gas producing formations. These fresh water zones exist from the surface to the base of the Ojo Alamo formation. The Ojo Alamo depth averages 2385 feet in the proposed Rosa Tight Gas Area.

Most wells drilled in the Rosa Area are drilled with natural mud to an average depth of 3700 feet. After intermediate casing is set, the remainder of the well is drilled with natural gas. Neither the natural mud or gas will contaminate any fresh water zone.

Normal casing designs in the Rosa Area consist of 9 5/8" or 10 3/4" O. D. surface casing being set from the surface to an average depth of 3700 feet. The cementing of the intermediate casing includes enough cement to cover formations to a depth above the Ojo Alamo formation. The cement covers the Pictured Cliffs, Fruitland, and Kirtland formations which are possible oil and gas bearing formations throughout the area. The production casing is cemented from total depth to a depth above the Mesa Verde formation, or to a point approximately 3000 feet above total depth. This cement covers the Dakota, Gallup, and Mesa Verde which are possible oil and gas bearing formations. A temperature survey is run after cementing the production casing to assure that all necessary zones are covered with cement. Therefore, all oil, gas and water bearing formations in this area are isolated from each other by cement and casing. The major water aquifer in the area, the Ojo Alamo formation, as well as the Pictured Cliffs, Fruitland, and Kirtland formations

is covered by cement and two strings of casing to protect them from contamination with other formations.

Stimulation of the Dakota formation involves large fracture treatments, usually consisting of a one or two percent potassium chloride water base that will not harm a fresh water aquifer. Fresh water protection is adequate even with these large stimulation treatments due to zone isolation caused by cementation. The large distance of over 5500 feet between the Dakota formation and the Ojo Alamo fresh water acquifer is additional insurance that no existing fresh water zone will be contaminated by stimulation of Dakota wells in this area.

Therefore, New Mexico and Federal regulations will protect any fresh water supply that may be affected by drilling, completing and producing the Dakota formation in the Rosa Tight Gas Area.

CONCLUSION

Evidence presented in this report substantiate the following for the Four Corners Gas Producers' proposed Rosa Tight Gas Area:

(1) The estimated average in situ gas permeability, throughout the Dakota pay section, is expected to be 0.1 millidarcy or less;

(2) For an average Dakota well depth of 7950 feet, the stabilized production rate at atmospheric pressure of wells completed for production in the Dakota formation is not expected to exceed the maximum allowable rate of 336 MCF of natural gas per day without stimulation;

(3) No well drilled into the Dakota formation in the Rosa Area is expected to produce, without stimulation, more than five barrels of crude oil per day.

The proposed Rosa Tight Gas Area meets all the specifications required as stated above, and should be designated a tight formation in the Basin Dakota pool under Section 107 of the Natural Gas Policy Act of 1978.

LIST OF EXHIBITS

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
1	Dakota Reservoir Map	Show location of Rosa Tight Gas Area with respect to Basin Dakota production.
2	Dakota Formation Well Completion and Production Map	Show production figures of completed and dry Dakota wells in and around the tight formation area.
3	Rosa Tight Gas Area Wells	List production figures of completed and dry Dakota wells in the tight formation area.
4	Type Log	Show log characteristics and depth of Dakota formation.
5	Cross Section A-A'	Show Dakota formation development in a west-east direction.
6	Cross Section B-B'	Show Dakota formation development in a north-south direction.
7	Core Analyisis Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	Show average laboratory core permeability.
8	Core Analysis El Paso Natural Gas Company San Juan 30-5 Unit No. 28-X	Show average laboratory core permeability.
9	Core Analysis El Paso Natural Gas Company San Juan 30-6 Unit No. 31	Show average laboratory core permeability.
10	Core Analysis Amoco Production Company Rosa Unit No. 1	Show average laboratory core permeability.
11	Core Analysis Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	Show average laboratory core permeability.
12	Core Analysis Blackwood & Nichols, LTD. Northeast Blanco Unit No. 1	Show average laboratory core permeability.
13	Technical Paper	Present relationship between laboratory and in situ permeability.
14	Determination of In Situ Permeability	Show method of determining in situ permeability from laboratory core analysis.
15	Summary of Permeability Data	Shows summary of permeability data, average laboratory permeability and in situ permeability.
16	Natural Production Tests	Lists natural production tests taken and average results.
17	Darcy's Law Calculation	Show unstimulated gas production rate using average in situ permeability.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 3
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

EXHIBIT NO. 3

ROSA TIGHT GAS AREA WELLS

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Sunray DX Oil Co.	#1 Jicarilla Tribal	NW/NW 34 30-3	8213	09/64	D&A	---	---
El Paso Natural Gas Co.	Carson #2	NW/SW 7 30-4	8083	09/79	869/0	302/0	.055/0
El Paso Natural Gas Co.	39 San Juan 30-4 Unit	SE/NW 18 30-4	8425	02/81	2506/0	New Well	---
Coastline Petroleum	1 Schalk-76	SW/NW 25 30-4	8675	02/75	D&A	---	---
Southland Royalty Co.	#1 Carson	NW/SW 1 30-5	8030	10/69	2129/0	129/0	.518/0
Schalk Development Co.	Schalk #54	SE/NE 2 30-5	8018	01/73	2501/0	111/0	.297/0
Schalk Development Co.	Schalk #55	NE/NE 3 30-5	7940	03/73	3298/0	34/0	.126/0
Southland Royalty Co.	Cat Draw #1	SW/SW 4 30-5	7780	09/68	2074/0	SI	.186/0
Northwest Pipeline Corp.	39 San Juan 30-5 Unit	SW/NE 7 30-5	7686	07/75	1703/0	67/0	.123/0
Northwest Pipeline Corp.	37 San Juan 30-5 Unit	NE/SW 8 30-5	7688	01/74	3944/0	87/0	.503/0
Northwest Pipeline Corp.	70 San Juan 30-5 Unit	NE/NE 9 30-5	7752	12/80	1584/0	New Well	---
Northwest Pipeline Corp.	49 San Juan 30-5 Unit	SW/SW 9 30-5	7683	12/80	855/0	New Well	---
Northwest Pipeline Corp.	73 San Juan 30-5 Unit	NW/NE 10 30-5	7919	03/81	2635/0	New Well	---
Northwest Pipeline Corp.	72 San Juan 30-5 Unit	SW/SW 10 30-5	7790	04/81	2456/0	New Well	---
Schalk Development Co.	Schalk #57	NE/NW 12 30-5	8009	07/73	5107/0	148/0	.452/0
Northwest Pipeline Corp.	52 San Juan 30-5 Unit	SE/SW 15 30-5	7920	03/81	2679/0	New Well	---
Northwest Pipeline Corp.	53 San Juan 30-5 Unit	NE/SW 16 30-5	7685	12/80	1209/0	New Well	---
Northwest Pipeline Corp.	47 San Juan 30-5 Unit	NW/SW 17 30-5	7794	08/75	1610/0	129/0	.235/0

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	38 San Juan 30-5 Unit	SW/NE 18 30-5	7667	06/80	2035/0	New Well	---
Northwest Pipeline Corp.	6 San Juan 30-5 Unit	SW/SW 19 30-5	7607	03/56	P&A	---	---
Northwest Pipeline Corp.	48 San Juan 30-5 Unit	NW/NE 20 30-5	7790	01/80	3691/0	New Well	---
Northwest Pipeline Corp.	27 San Juan 30-5 Unit	SW/SW 20 30-5	7646	12/59	1309/0	24/0	.248/0
Northwest Pipeline Corp.	51 San Juan 30-5 Unit	NW/NE 21 30-5	7759	12/80	4792/0	New Well	---
Northwest Pipeline Corp.	71 San Juan 30-5 Unit	SW/SW 22 30-5	7807	12/80	2145/0	New Well	---
El Paso Natural Gas Co.	28-23-X San Juan 30-5 Unit	NE/NE 23 30-5	8075	09/59	D&A	---	---
Northwest Pipeline Corp.	38 San Juan 31-6 Unit	NE/NW 2 30-6	7832	04/81	2828/0	New Well	---
El Paso Natural Gas Co.	31 San Juan 30-6 Unit	SE/SW 33 30-6	7550	07/59	964/0	29/0	.255/0
Blackwood & Nichols	12 NE Blanco Unit	SW/NE 18 30-7	7590	06/60	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #42	SW/NE 19 31-4	not given	11/61	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #43	NW/SE 19 31-4	8158	05/62	2352/0	98/0	.064/0
Irving Pasternak	Rosa Unit #49	SW/SW 27 31-4	8430	11/63	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #63	SW/NE 30 31-4	8088	11/77	225/0	63/0	.004/0
Coastline Petroleum	1 Schalk-58	NE/SW 2 31-5	7856	08/73	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #53	NW/NE 8 31-5	7900	03/70	1043/0	126/0	.668/0
Northwest Pipeline Corp.	Rosa Unit #80	NE/SW 8 31-5	7845	03/81	2155/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #70	NW/NW 10 31-5	8162	01/66	1500/0	261/0	.248/0
Northwest Pipeline Corp.	Rosa Unit #48	SW/SE 11 31-5	8151	12/62	3207/0	326/0	.218/0
Northwest Pipeline Corp.	Rosa Unit #40	SW/NW 11 31-5	8358	07/61	3560/0	271/0	.216/0
Northwest Pipeline Corp.	Rosa Unit #61	SE/SW 13 31-5	8124	11/77	337/0	55/0	.074/0
Northwest Pipeline Corp.	Rosa Unit #65	NE/NE 17 31-5	7870	08/78	3095/0	163/0	.104/0
Northwest Pipeline Corp.	Rosa Unit #68	NW/SW 17 31-5	not given	08/80	5757/0	609/0	.093/0
Northwest Pipeline Corp.	Rosa Unit #62	NE/NW 25 31-5	8088	11/77	342/0	82/0	.106/0
Northwest Pipeline Corp.	Rosa Unit #64	NE/NE 29 31-5	7950	10/78	1843/0	175/0	.132/0
Northwest Pipeline Corp.	Rosa Unit #52	NW/NW 33 31-5	7980	02/70	2401/0	248/0	1.095/0
Northwest Pipeline Corp.	Rosa Unit #55	NE/SE 34 31-5	8056	10/74	264/0	167/0	.386/0
Northwest Pipeline Corp.	Rosa Unit #56	SW/NW 35 31-5	8200	11/75	675/0	96/0	.232/26
Northwest Pipeline Corp.	Rosa Unit #54	NE/SW 36 31-5	8284	09/74	304/0	SI	.029/0
Amoco Production Co.	Rosa Unit 35-X	NE/SW 5 31-6	7822	10/59	D&A Dak. MV Comp.	---	---
Amoco Production Co.	Rosa Unit #36	SE/NE 11 31-6	7955	12/59	P&A MV Comp.	---	---
Amoco Production Co.	Rosa Unit #1	SW/SE 11 31-6	7865	09/52	560/0 (P&A)		---
Northwest Pipeline Corp.	Rosa Unit #66	NW/SW 13 31-6	7957	08/78	4427/0	245/0	.928/0
Amoco Production Co.	Rosa Unit #69	NW/NW 16 31-6	7918	09/80	P&A	---	---
Northwest Pipeline Corp.	79 San Juan 31-6 Unit	NE/SW 22 31-6	7757	03/81	1858/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #51	NE/NW 23 31-6	7823	01/70	1385/0	170/0	.736/0
Northwest Pipeline Corp.	36 San Juan 31-6 Unit	NE/NE 27 31-6	7806	03/81	2557/0	New Well	---
Northwest Pipeline Corp.	24 San Juan 31-6 Unit	NE/SW 27 31-6	7939	12/73	1341/0	SI	.269/0
Northwest Pipeline Corp.	16 San Juan 31-6 Unit	SE/SW 33 31-6	7895	07/59	1783/0	SI	.074/0
Northwest Pipeline Corp.	33 San Juan 31-6 Unit	SW/NE 34 31-6	8712	06/80	4119/0	New Well	---
Northwest Pipeline Corp.	35 San Juan 31-6 Unit	NE/NE 35 31-6	7908	07/80	2643/0	New Well	---
Northwest Pipeline Corp.	31 San Juan 31-6 Unit	SE/SE 35 31-6	7796	06/80	3770/0	New Well	---
Northwest Pipeline Corp.	37 San Juan 31-6 Unit	SW/SE 36 31-6	7952	04/81	2370/0	New Well	---
Blackwood & Nichols	58 NE Blanco Unit	NE/NE 13 31-7	7975	11/59	2461/0	217/0	1.387/0
Blackwood & Nichols	57 NE Blanco Unit	NE/NE 21 31-7	7780	09/59	1235/0	37/0	.444/0
Blackwood & Nichols	55 NE Blanco Unit	NW/NE 22 31-7	7856	10/58	275/0	27/0	.182/0
Blackwood & Nichols	1 NE Blanco Unit	SE/NE 27 31-7	7792	10/52	536/0	217/0	2.398/0
Amoco Production Co.	McKay #1	NW/NE 28 31-7	7765	03/71	D&A	---	---
Blackwood & Nichols	56 NE Blanco Unit	NE/NE 34 31-7	7660	11/58	2839/0	30/0	.417/0

EXHIBIT NO. 7

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 30-5 Unit No. 27
Basin Dakota Field
SW/SW, Sec. 20, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7650-7651	1	0.01
7651-7652	1	0.01
7652-7653	1	0.01
7653-7654	1	0.02
7654-7655	1	0.01
7655-7656	1	0.02
7658-7659	1	0.02
7661-7662	1	0.03
7662-7663	1	0.02
7667-7668	1	0.02
7669-7670	1	0.01
7670-7671	1	0.02
7688-7689	1	0.01
7689-7690	1	0.01
7690-7691	1	0.60
7691-7692	1	0.01
7692-7693	1	0.01
7694-7695	1	0.02
7696-7697	1	0.25
7697-7698	1	0.01
7707-7708	1	0.01
7708-7709	1	0.02
7709-7710	1	0.03
7719-7720	1	0.01
7720-7721	1	1.51
7721-7722	1	0.07
7722-7723	1	0.25
7723-7724	1	0.10
7724-7725	1	0.01
7727-7728	1	0.02
7728-7729	1	0.04
7729-7730	1	0.02
7730-7731	1	0.01
7731-7732	1	0.04
7732-7733	1	0.02
7733-7734	1	0.66
7769-7770	1	0.04
7770-7771	1	0.03
7771-7772	1	0.03
7773-7774	1	0.01
7774-7775	1	0.01
7775-7776	1	0.02
7776-7777	1	1.44
7777-7778	1	0.11
7778-7779	1	0.10
7779-7780	1	0.21
7780-7781	1	0.13

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 7
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

San Juan 30-5 Unit No. 27, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.01
7783-7784	1	0.03
7784-7785	1	0.03
7785-7786	1	0.09
7786-7787	1	0.02
7787-7788	1	1.01
7788-7789	1	0.05
7789-7790	1	0.06
7790-7791	1	0.05
7791-7792	1	0.31
7792-7793	1	0.03
7793-7794	1	0.02
7794-7795	1	0.01
7795-7796	1	0.05
7796-7797	1	0.18
7797-7798	1	0.61
7798-7799	1	0.34
TOTAL	65	9.07

Avg. K = $\frac{9.07}{65}$ = 0.140 md.

CHEMICAL & GEOLOGICAL LABORATORIES
Farmington

CORE ANALYSIS REPORT

ompany El Paso Natural Gas Company — Date September 23, 1959 Lab. No.
Well No. San Juan 30-5 #27-20 — Location Sec. 20-30N-5W
ield Wildcat — Formation Dakota
ounty Rio Arriba — Depths 7649' - 7799'
ate New Mexico — Drilling Fluid Water Base Mud

LEGEND: C—Crack, F—Fracture, H—Horizontal, O—Open, NF—No Fracture, IS—Insufficient Sample, S—Slight, St—Stain, V—Vertical, Vu—Vugs

* Permeability probably caused by existing shale interlaminations

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY PERCENT	PERMEABILITY MILLIDARCIES HORIZONTAL	PERMEABILITY MILLIDARCIES VERTICAL	SATURATIONS % PORE SPACE RESIDUAL OIL	SATURATIONS % PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	SOLUBILITY 15 % ACID
		Core No. 1 7649 - 7710								
1	VF	7650-51	7.7	0.01		Trace	27.8			
2	NF	7651-52	8.5	0.01		Trace	16.7			
3	VF	7652-53	6.7	0.01		Trace	12.2			
4	VF	7653-54	7.7	0.02		Trace	12.4			
5	VF	7654-55	5.2	0.01		0	21.2			
6	VF	7655-56	8.6	0.02		0	15.8			
7	VF	7658-59	8.8	0.02		Trace	12.4			
8	VHF	7661-62	10.2	0.03		0	15.2			
9	VF	7662-63	9.6	0.02		0	19.2			
10	VHF	7667-68	10.0	0.02		Trace	20.5			
11	VHF	7669-70	6.5	0.01		Trace	15.4			
12	VHF	7670-71	7.9	0.02		1.4	20.6			
13	HF	7688-89	4.9	0.01		Trace	26.1			
14	HF	7689-90	5.0	0.01		Trace	24.2			
15	HF	7690-91	5.9	0.60*		Trace	35.9			
16	HF	7691-92	3.7	0.01		Trace	94.9			
17	VHF	7692-93	7.8	0.01		Trace	54.7			
18	NF	7694-95	9.3	0.02		Trace	14.2			
19	HF	7696-97	11.4	0.25*		0	27.7			
20	NF	7697-98	6.3	0.01		0	18.6			
21	VHF	7701-02	2.6	0.01		0	62.3			
22	VHF	7707-08	2.0	0.01		0	44.5			
23	VHF	7708-09	6.1	0.02		0	36.0			
24	VHF	7709-10	5.9	0.03		Trace	33.9			

El Paso Natural Gas Company
San Juan 30—5 #27-20

Wildcat
Rio Arriba County, New Mexico

C—Crack
F—Fracture
H—Horizontal
O—Open

* Permeability probably caused by existing shale interlaminations

LEGEND
NF—No Fracture
[illegible] Sample

S—Slight
St—Stain
V—Vertical
Vu—Vugs

Sample No.	Legend	Depth, Feet	Effective Porosity % Porespace	Permeability Millidarcies Horizontal	Permeability Millidarcies Vertical	Saturation % Pore Space Residual Oil	Saturation % Pore Space Total Water	Connate Water	Solubility Mud Acid	Solubility 15% Acid
		Core No. 2 7710 - 7719 Recovered 9'								
		No samples analyzed								
		Core No. 3 7719 - 7727 Recovered 6½'								
25	VHF	7719-20	3.8	0.01		0	30.3			
26	HF	7720-21	2.8	1.51*		0	60.7			
27	HF	7721-22	3.4	0.07		0	33.8			
28	HF	7722-23	2.4	0.25*		0	60.8			
29	HF	7723-24	4.5	0.10*		0	51.6			
30	VHF	7724-25	2.6	0.01		0	38.5			
		Core No. 4 7727 - 7738 Recovered 10'								
31	VHF	7727-28	3.0	0.02		0	16.0			
32	VHF	7728-29	3.4	0.04		0	11.8			
33	VHF	7729-30	5.4	0.02		0	11.3			
34	VHF	7730-31	1.8	0.01		0	12.2			
35	HF	7731-32	3.9	0.04		0	13.9			
36	VF	7732-33	2.5	0.02		0	12.0			
37	HF	7733-34	3.9	0.66*		0	11.0			
		Core No. 5 7738 - 7799 Recovered 61'								
38	NF	7768-69	10.1	0.04		0	39.2			
39	NF	7769-70	10.8	0.04		0	45.4	41.5		
40	NF	7770-71	10.5	0.03		0	47.1			
41	NF	7771-72	7.7	0.03		0	38.4			
	-	7772-73	No sample taken							
42	NF	7773-74	5.9	0.01		Trace	49.2			
43	NF	7774-75	5.9	0.01		Trace	48.1			
44	VF	7775-76	2.5	0.02		Trace	55.2			
45	VF	7776-77	5.7	1.44*		Trace	49.6			
46	NF	7777-78	6.9	0.11		Trace	53.3	44.1		
47	NF	7778-79	7.4	0.10		0	39.3			
48	NF	7779-80	7.6	0.21		0	37.9	42.0		
49	NF	7780-81	6.2	0.13		0	40.3			
50	NF	7781-82	4.6	0.10		Trace	34.1			
51	VF	7782-83	3.8	0.01		Trace	86.8			
52	HF	7783-84	4.1	0.03		Trace	73.7			
53	NF	7784-85	4.2	0.03		Trace	68.3			
54	NF	7785-86	4.6	0.09		0	41.3			
55	NF	7786-87	5.4	0.02		0	53.0	44.7		
56	NF	7787-88	7.0	1.01*		0	42.0			
57	NF	7788-89	6.6	0.05		0	45.9	49.5		
58	NF	7789-90	6.9	0.06		0	49.0			
59	NF	7790-91	6.9	0.05		0	31.2			
60	NF	7791-92	6.4	0.31		0	26.1			
61	NF	7792-93	3.2	0.03		0	26.3			

El Paso Natural Gas Company
San Juan 30-5 #27-20

Wildcat
Rio Arriba County, New Mexico

LEGEND

C—Crack
F—Fracture
H—Horizontal
O—Open

NF—No Fracture
IS—Insufficient Sample

S—Slight
St—Stain
V—Vertical
Vu—Vugs

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY % PORESPACE	PERMEABILITY MILLIDARCIES HORIZONTAL	VERTICAL	SATURATIONS % PORE SPACE RESIDUAL OIL	% PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	10 % ACID
		Core No. 5 continued								
62	VF	7793-94	5.8	0.02		0	39.1			
63	VF	7794-95	4.0	0.01		0	52.3			
64	NF	7795-96	8.3	0.05		0	49.9			
65	NF	7796-97	9.5	0.18		Trace	51.7			
66	NF	7797-98	9.4	0.61		Trace	52.1			
67	NF	7798-99	9.4	0.34		Trace	53.2	46.2		

EXHIBIT NO. 8

Company: El Paso Natural Gas Company
Well: San Juan 30-5 Unit No. 28-X
Basin Dakota Field
NE/NE, Sec. 23, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8075-8076	1	0.02
8076-8077	1	0.01
8077-8078	1	0.01
8078-8079	1	0.01
8079-8080	1	0.01
8080-8081	1	0.01
8081-8082	1	0.01
8082-8083	1	0.01
8083-8084	1	0.01
8084-8085	1	0.01
8085-8086	1	0.01
8090-8091	1	0.01
8091-8092	1	0.01
8092-8093	1	0.01
8093-8094	1	0.01
8094-8095	1	0.01
8095-8096	1	0.01
8096-8096.8	.8	0.01
8116-8117	1	0.03
8117-8118	1	0.01
8118-8119	1	0.01
8119-8120	1	0.01
8120-8121	1	0.02
8121-8122	1	0.01
8122-8123	1	0.01
8123-8124	1	0.01
8124-8125	1	0.01
8125-8126	1	0.01
8126-8127	1	0.01
8127-8128	1	0.01
8128-8129	1	0.01
8129-8130	1	0.02
8130-8130.9	.9	0.01
8133-8134	1	0.01
8134-8135	1	0.01
8138-8139	1	0.01
8139-8140	1	0.01
8140-8141	1	0.01
8141-8142	1	0.01
8142-8143	1	0.01
8143-8144	1	0.01
8144-8145	1	0.01
8145-8146	1	0.01
8146-8147	1	0.01
8147-8148	1	0.65
8148-8149	1	0.01
8155-8156	1	0.01
8156-8157	1	0.01
8157-8158	1	0.01
8158-8159	1	0.01
8159-8160	1	0.01
8160-8161	1	0.05
8161-8162	1	0.02
8162-8163	1	7.2

San Juan 30-5 Unit No. 28-X, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8163-8164	1	0.01
8164-8165	1	0.02
8165-8166	1	0.01
8166-8167	1	0.01
8167-8168	1	0.01
8190-8191	1	2.10
8191-8192	1	0.24
8192-8193	1	0.01
8193-8194	1	0.07
8200-8201	1	0.01
8201-8202	1	0.01
8202-8203	1	0.01
8203-8204	1	0.01
8204-8205	1	0.01
8205-8206	1	0.01
8206-8207	1	0.01
8207-8208	1	0.01
8208-8209	1	0.01
8209-8210	1	0.01
8210-8211	1	0.01
8222-8223	1	0.19
8223-8224	1	0.01
8224-8225	1	0.01
8225-8226	1	0.01
8226-8227	1	0.01
8229-8230	1	0.01
8230-8231	1	0.02
8238-8239	1	0.01
8239-8240	1	0.01
8240-8241	1	0.01
8241-8242	1	0.01
8242-8243	1	0.28
8246-8247	1	0.01
8247-8248	1	0.01
TOTAL	87.7	11.66

Avg. $\frac{11.66}{87.7}$ = 0.133 md

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

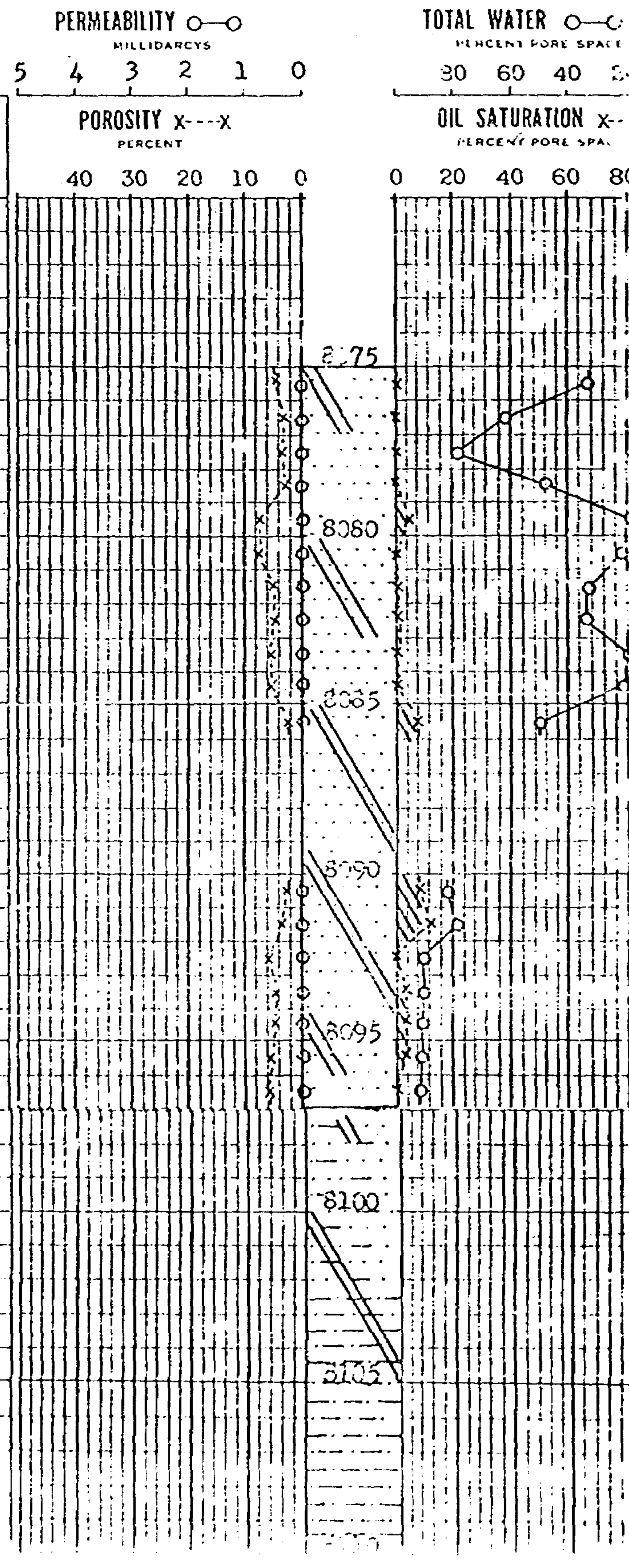
COMPANY: EL PASO NATURAL GAS COMPANY DATE ON: 8/30/59 FILE NO.: RP-3-1065
WELL: SAN JUAN 30-5 No. 28-23 - X DATE OFF: 9/8/59 ENGRS.: ENGLISH
FIELD: BLANCO MESA VERDE DAKOTA WILDCAT FORMATION: DAKOTA ELEV.: 6753' DF
COUNTY: RIO ARRIBA STATE: N.MEXICO DRLG. FLD.: OIL EMULSION CORES: DIAMOND
LOCATION: SEC23 T30N R5W REMARKS: SAMPLED BY CLIENT

SAND · SHALE · LIMESTONE · DOLOMITE · CONGLOMERATE · VERTICAL FRACTURE · CHERT

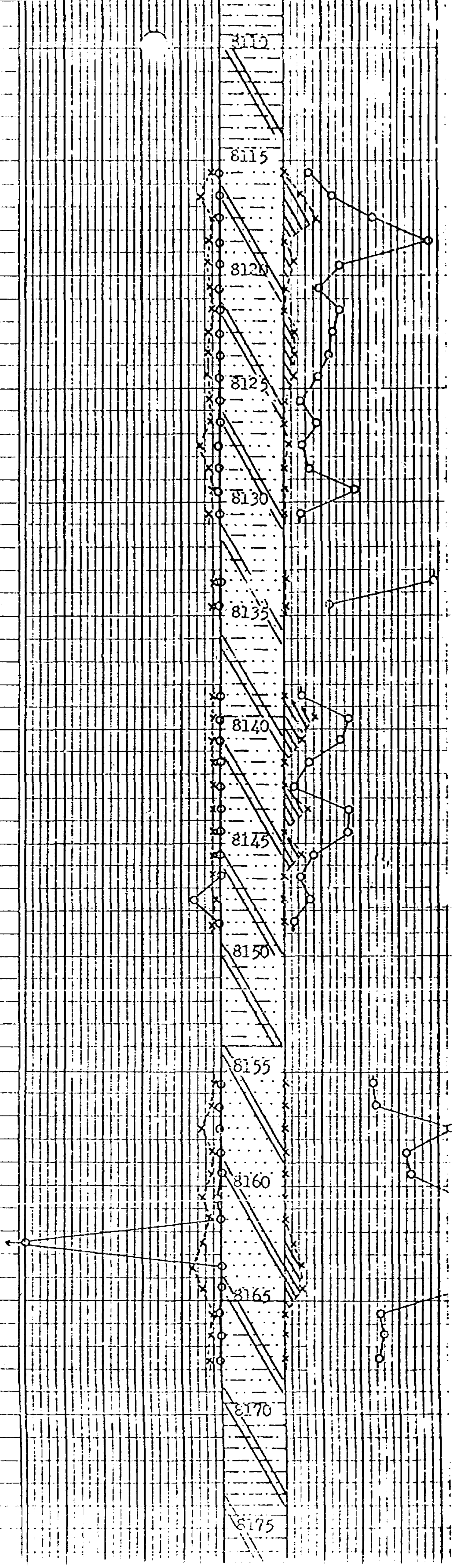
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	TOTAL WATER	BOYLE'S LAW POROSITY	PROD.
1	8075-76	0.02	4.6	0.0	32.6		
2	76-77	<0.01	3.4	0.0	61.8		
3	77-78	<0.01	2.8	0.0	78.6		
4	78-79	<0.01	2.5	0.0	48.0		
5	79-80	<0.01	7.6	6.6	19.8		
6	80-81	<0.01	7.0	0.0	21.4		
7	81-82	<0.01	4.5	0.0	33.4		
8	82-83	<0.01	4.3	0.0	34.9		
9	83-84	<0.01	5.5	0.0	20.0		
10	84-85	<0.01	5.2	0.0	21.2		
11	85-86	<0.01	2.4	8.3	50.0		
12	8090-91	<0.01	2.2	9.1	81.8		
13	91-92	<0.01	3.7	13.5	78.4		
14	92-93	<0.01	5.7	0.0	87.7		
15	93-94	<0.01	4.2	4.8	90.5		
16	94-95	<0.01	4.3	4.7	88.4		
17	95-96	<0.01	4.8	4.2	87.5		
18	96-96.8	<0.01	5.7	0.0	91.3		

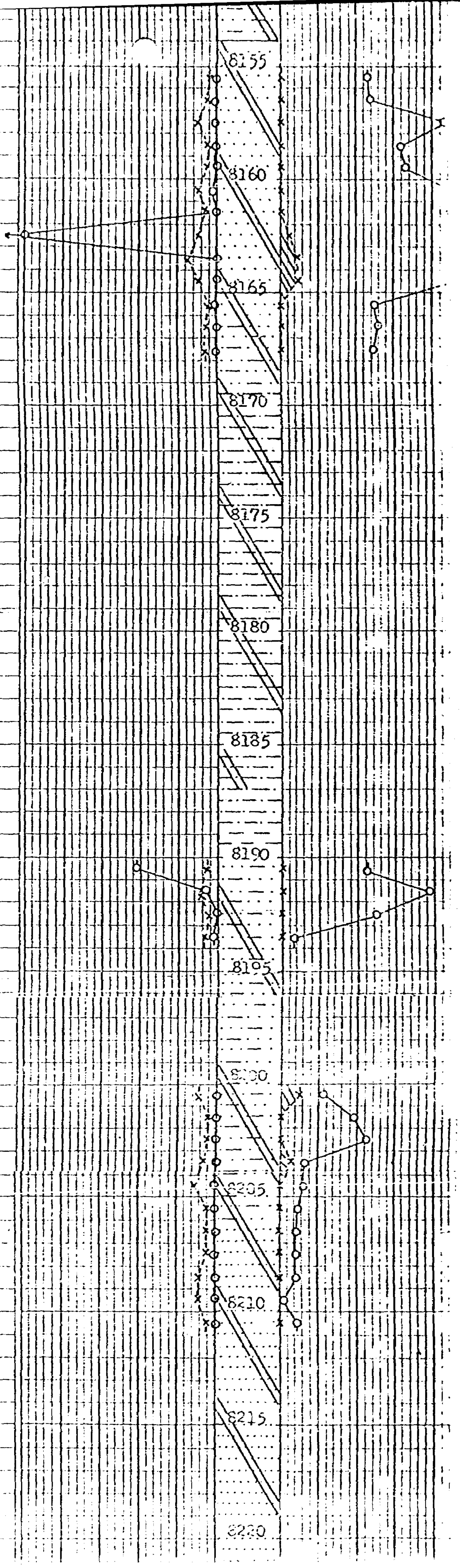
COMPLETION COREGRAPH



19	8115.5-16	0.01	2.2	0.0	86.4	1.9
20	16-17	0.03	5.0	10.0	74.0	2.9
21	17-18	<0.01	1.1	18.2	54.6	2.9
22	18-19	<0.01	2.5	0.0	24.0	3.6
23	19-20	<0.01	3.4	5.9	70.6	4.8
24	20-21	0.02	2.5	0.0	80.1	3.6
25	21-22	<0.01	2.1	0.0	71.4	3.1
26	22-23	<0.01	3.2	6.2	74.9	3.4
27	23-24	<0.01	3.4	5.9	76.5	4.3
28	24-25	<0.01	3.8	5.3	81.6	4.1
29	25-26	<0.01	3.0	0.0	90.0	3.3
30	26-27	<0.01	3.4	0.0	82.4	3.5
31	27-28	<0.01	5.8	3.4	89.7	2.4
32	28-29	<0.01	2.9	0.0	86.2	2.6
33	29-30	0.02	1.9	0.0	63.1	1.1
34	30-30.9	<0.01	3.2	0.0	90.7	4.3
35	8133-34	<0.01	1.9	0.0	21.0	2.8
36	34-35	<0.01	2.1	0.0	76.3	4.0
37	8138-39	<0.01	1.8	0.0	89.0	1.7
38	39-40	<0.01	1.2	16.7	66.6	1.0
39	40-41	<0.01	1.7	11.8	70.6	1.9
0	41-42	<0.01	1.4	0.0	85.6	2.0
1	42-43	0.01	1.8	0.0	94.4	2.2
2	43-44	<0.01	1.5	13.3	66.8	2.2
3	44-45	<0.01	0.9	0.0	66.7	1.9
4	45-46	<0.01	1.9	10.5	84.3	2.2
5	46-47	<0.01	1.3	0.0	92.4	3.3
6	47-48	0.65	1.4	0.0	85.7	5.1
7	48-49	<0.01	2.2	0.0	95.0	1.8
8	8155-56	<0.01	1.1	0.0	54.5	
9	56-57	<0.01	2.3	0.0	52.2	
0	57-58	0.01	5.4	0.0	14.8	
1	58-59	<0.01	2.2	0.0	36.3	
2	59-60	<0.01	1.8	0.0	33.3	
3	60-61	0.05	5.7	0.0	10.5	
4	61-62	0.02	3.6	0.0	11.1	
5	62-63	7.2	4.8	4.2	8.3	
5	63-64	0.01	7.2	9.7	8.5	
7	64-65	0.02	5.1	9.8	7.8	
3	65-66	<0.01	1.2	0.0	50.0	
[illegible]	66-67	<0.01	2.9	0.0	48.2	
[illegible]	67-68	<0.01	2.4	0.0	50.0	



48	8155-56	<0.01	1.1	0.0	54.5
49	56-57	<0.01	2.3	0.0	52.2
50	57-58	0.01	5.4	0.0	14.8
51	58-59	<0.01	2.2	0.0	36.3
52	59-60	<0.01	1.8	0.0	33.3
53	60-61	0.05	5.7	0.0	10.5
54	61-62	0.02	3.6	0.0	11.1
55	62-63	7.2	4.8	4.2	8.3
56	63-64	0.01	7.2	9.7	8.5
57	64-65	0.02	5.1	9.8	7.8
58	65-66	<0.01	1.2	0.0	50.0
59	66-67	<0.01	2.9	0.0	48.2
60	67-68	<0.01	2.4	0.0	50.0
1	8190-91	2.1	2.7	0.0	55.6
2	91-92	0.24	2.8	0.0	21.4
3	92-93	0.01	2.0	0.0	50.0
4	93-94	0.07	2.6	0.0	92.3
	8200-01	<0.01	4.3	11.6	76.8
	01-02	<0.01	1.3	0.0	61.5
	02-03	0.01	1.7	0.0	35.3
3	03-04	<0.01	2.9	6.9	86.3
	04-05	<0.01	5.5	0.0	85.5
	05-06	<0.01	1.9	0.0	89.4
	06-07	<0.01	1.6	0.0	93.8
	07-08	<0.01	1.4	0.0	93.0
	08-09	<0.01	4.2	0.0	95.0
	09-10	<0.01	4.1	0.0	97.6
	10-11	<0.01	1.4	0.0	93.0



	[illegible]-01	[illegible]	[illegible]	11.6	76.8
6	01-02	<0.01	1.3	0.0	61.5
7	02-03	0.01	1.7	0.0	[illegible].3
[illegible]	03-04	<0.01	2.9	6.9	86.3
9	04-05	<0.01	5.5	0.0	85.5
0	05-06	<0.01	1.9	0.0	89.4
1	06-07	<0.01	1.6	0.0	93.8
2	07-08	<0.01	1.4	0.0	93.0
3	08-09	<0.01	4.2	0.0	95.0
4	09-10	<0.01	4.1	0.0	97.6
5	10-11	<0.01	1.4	0.0	93.0
6	8222-23	0.19	3.9	0.0	97.5
7	23-24	<0.01	1.0	20.0	80.0
8	24-25	<0.01	0.6	0.0	66.6
9	25-26	0.01	1.3	0.0	15.4
0	26-27	<0.01	0.8	0.0	25.0
1	8229-30	<0.01	1.2	0.0	83.4
2	30-31	0.02	1.4	0.0	14.3
	8238-39	0.01	0.9	0.0	44.5
	39-40	<0.01	1.3	0.0	46.1
	40-41	<0.01	0.9	0.0	66.6
	41-42	0.01	1.0	0.0	40.0
	42-43	0.28	4.5	0.0	93.4
	8246-47	<0.01	3.3	6.1	88.0
	8247-48	<0.01	4.6	4.4	91.3

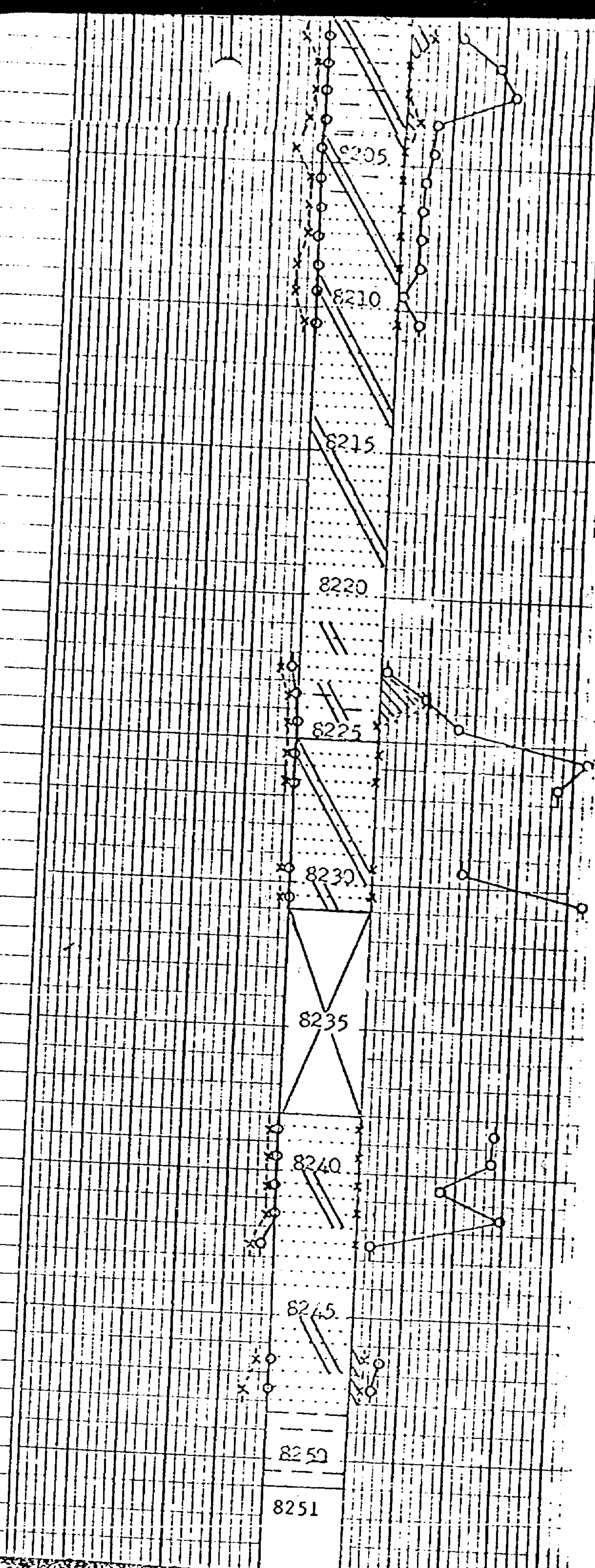


EXHIBIT NO. 9

Company: El Paso Natural Gas Company
Well: San Juan 30-6 Unit No. 31
Basin Dakota Field
SE/SW, Sec. 33, T30N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7635-7636	1	0.01
7636-7637	1	0.01
7637-7638	1	0.05
7638-7639	1	0.07
7639-7640	1	0.01
7640-7641	1	0.10
7641-7642	1	< 0.01
7642-7643	1	< 0.01
7643-7644	1	0.01
7644-7645	1	< 0.01
7645-7646	1	0.01
7646-7647	1	< 0.01
7647-7648	1	< 0.01
7716-7717	1	0.13
7717-7718	1	0.04
7718-7719	1	0.01
7719-7720	1	0.90
7720-7721	1	< 0.01
7721-7722	1	< 0.01
7722-7723	1	< 0.01
7723-7724	1	< 0.01
7724-7725	1	< 0.01
7725-7726	1	< 0.01
7746-7747	1	0.04
7751-7752	1	0.01
7752-7753	1	0.06
7753-7754	1	1.90
7754-7755	1	0.27
7755-7756	1	0.01
7756-7757	1	0.03
7757-7758	1	0.17
7758-7759	1	0.05
7759-7760	1	0.90
7760-7761	1	1.00
TOTAL	34	5.90

$\text{Avg. } K = \frac{5.90}{34} = 0.174 \text{ md}$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANT'S EXHIBIT NO. 9
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

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CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

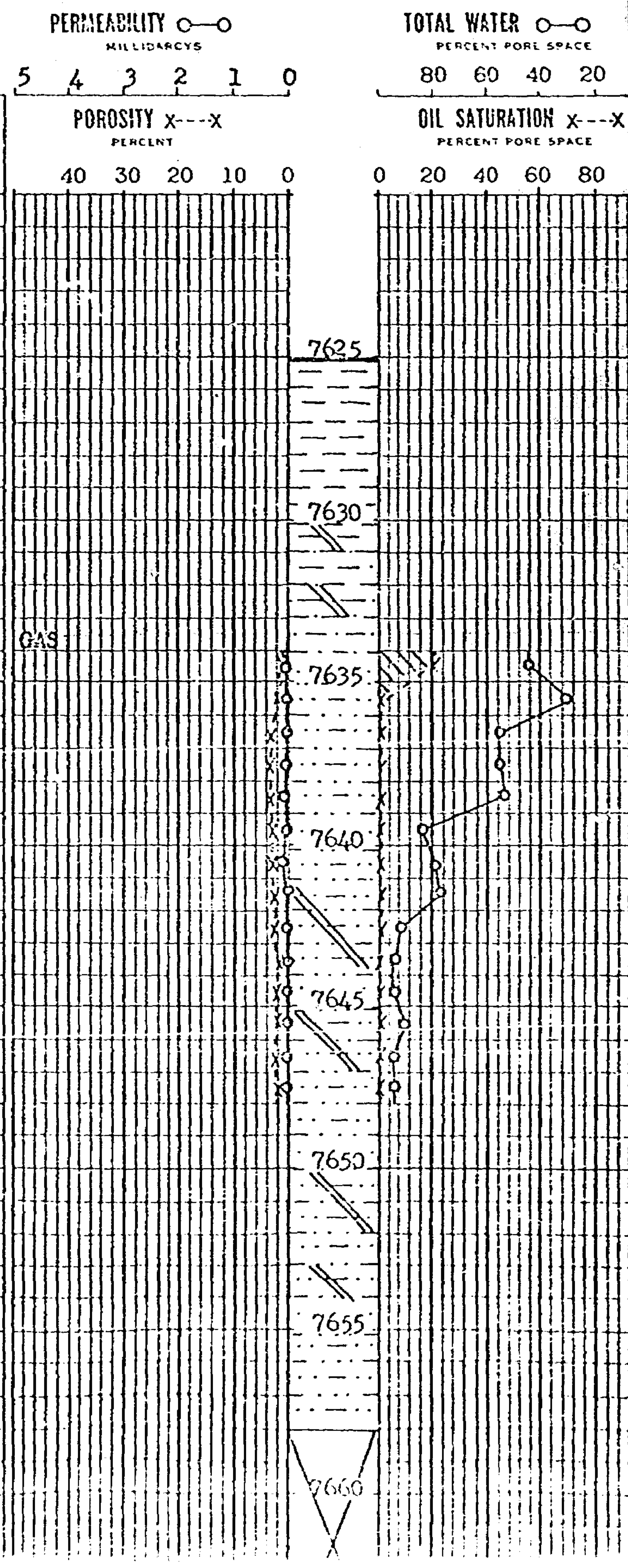
COMPANY	EL PASO NATURAL GAS COMPANY	DATE ON	5/31/59	FILE NO.	RP-3-997
WELL	SAN JUAN 30-6 No. 31	DATE OFF	6/8/59	ENGRS.	ENGLISH
FIELD	WILDCAT	FORMATION	DAKOTA	ELEV.	6364'DF
COUNTY	RIO ARRIBA STATE N.MEXICO	DRLG. FLD.	AS NOTED	CORES.	DIAMOND
LOCATION	SEC33 - T30N - R6W	REMARKS	SAMPLED BY CLIENT		

SAND — LIMESTONE — CONGLOMERATE — CHERT
SHALE — DOLOMITE — FRACTURES

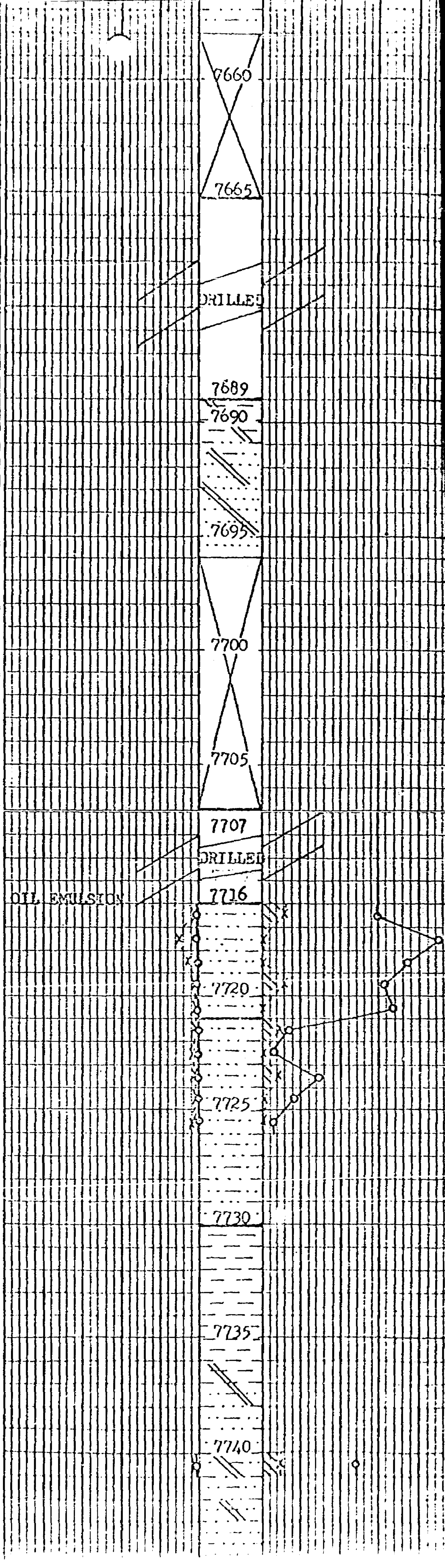
COMPLETION COREGRAPH

TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER		PROD
1	7634-35	<0.01	0.9	22.3	44.5		
2	35-36	0.01	1.9	0.0	31.6		
3	36-37	0.01	2.5	0.0	56.1		
4	37-38	0.05	3.2	0.0	56.3		
5	38-39	0.07	3.3	0.0	54.6		
6	39-40	0.01	2.5	0.0	84.1		
7	40-41	0.10	2.9	0.0	79.3		
8	41-42	<0.01	2.6	0.0	77.0		
9	42-43	<0.01	2.1	0.0	90.6		
10	43-44	0.01	1.8	0.0	94.4		
11	44-45	<0.01	2.0	0.0	95.1		
12	45-46	0.01	1.9	0.0	89.5		
13	46-47	<0.01	2.2	0.0	95.4		
14	47-48	<0.01	1.8	0.0	94.6		



15	7716-17	0.13	1.5	13.3	40.0
16	17-18	0.04	5.3	0.0	11.3
17	18-19	0.01	2.3	0.0	26.5
18	19-20	0.9	1.6	12.5	37.5
19	20-21	<0.01	0.6	0.0	33.3
20	21-22	<0.01	2.0	10.0	85.0
21	22-23	<0.01	1.7	0.0	94.0
22	23-24	<0.01	2.1	9.1	71.5
23	24-25	<0.01	1.2	0.0	83.4
24	25-26	<0.01	2.2	0.0	95.5
5	7740-41 V	0.04	1.9	10.5	52.7



25	7740-41	0.04	1.9	10.5	52.7
26	7746-47	0.04	1.6	31.3	50.0
27	7751-52	0.01	2.4	8.3	66.7
28	52-53	0.06	7.9	0.0	30.4
29	53-54	1.9	10.2	5.0	16.8
30	54-55	0.27	7.8	6.4	15.4
31	55-56	0.01	1.6	0.0	50.0
32	56-57	0.03	4.2	4.8	23.9
33	57-58	0.17	4.8	0.0	4.2
34	58-59	0.05	0.7	0.0	28.4
35	59-60	0.9	0.6	0.0	33.3
36	60-61	1.0	1.2	0.0	16.7

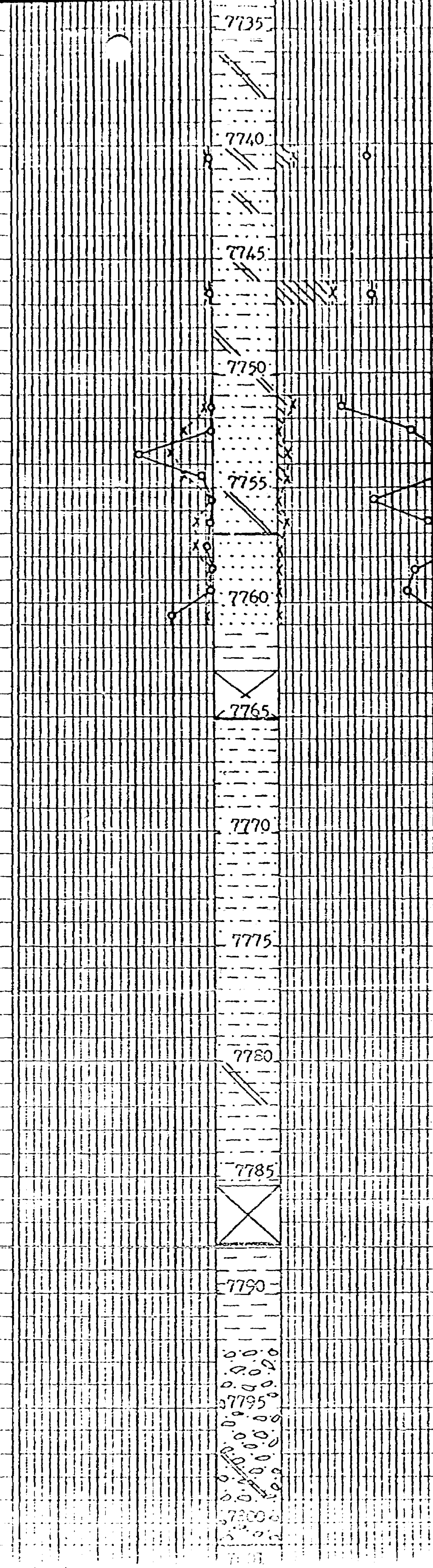


EXHIBIT NO. 10

Company: Amoco Production Company
Well: #1 Rosa Unit
Basin Dakota Field
SW/SE, Sec. 11, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7878-7879	1	0.05
7912-7914	2	0.05
7914-7916	2	0.34
7916-7923	7	0.05
7923-7928	5	0.18
7928-7930	2	0.59
7930-7931	1	0.05
7932-7936	4	0.05
TOTAL	24	

Weighted Total = 3.51 md

$$\text{Avg. K} = \frac{3.51}{24} = \underline{0.146 \text{ md}}$$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 10
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

DENVER REGION

AMOCO PRODUCTION COMPANY
CORE ANALYSIS LISTING

API WELL NUMBER - 30 039 07972 00
REGION 5 PAGE 01

API WELL NUMBER	GROUP NO.	CURRENT DATE	DATE ANALYZED
30 039 07972 00	05	81-05-05	49-05-06

WELL OPERATOR	LSE WELL NO	LEASE NAME	LATITUDE	LONGITUDE	ELEVATION
ORIG: STANOLIND OIL & GAS	1	ROSA UNIT	36.9082800	107.4291900	6348.0 DF
CURR: STANOLIND OIL & GAS	1	ROSA UNIT			

SEC TWP RGE QTR QTR QTR	COUNTY STATE	FIELD CODE	ORIG COMP DATE	TOTAL DEPTH
0311 C31N 006W	RIO ARRI, NM	00008500	49-09-10	8087.00

ANALYZING LABORATORY: STANOLIND OIL AND GAS COMPANY CITY: INPUT FORMAT 119

CORE TYPE----------DIAMOND
PRIMARY SPL TYPE---CONVENTIONAL - PLUG
SECONDARY SPL TYPE-
ANALYSIS TYPE------SUMMATION OF FLUIDS
CORE SIZE---------- INCHES
DRILLING FLUID----CHEMICAL MUD
EXTRACTION METHOD-RETORT
MULTIPLE DATA---NO

FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH	FORMATION STRAT MNEMONIC	FORMATION FIRST CORE DEPTH
24 GRUI	7872.00 [illegible]						

REMARKS:

DEPTH TOP	DEPTH BASE	INT SUB	PERMEABILITY HORIZ MAX	PERMEABILITY HORIZ 90	PERMEABILITY VERTICAL	POROSITY	OIL	WATER	GAS	DENSITY	LITHOLOGY
7873.00	7879.00	<	0.05 PH			5.0 PE	2.1 PO	18.5 PW			SAND
7912.00	7914.00	<	0.05 PH			4.2 PE	0.0 PO	6.5 PW			SAND
7914.00	7916.00		0.34 PH			6.5 PE	1.7 PO	13.4 PW			SAND
7916.00	7923.00	<	0.05 PH			2.9 PE	0.0 PO	3?.0 PW			SAND
7923.00	7928.00		0.18 PH			3.8 PE	15.4 PO	27.8 PW			SAND
7928.00	7930.00		0.59 PH			4.5 PE	4.3 PO	20.5 PW			SAND
7930.00	7931.00	<	0.05 PH			5.4 PE	0.0 PO	21.1 PW			SAND
7932.00	7936.00	<	0.05 PH			4.1 PE	2.8 PO	24.0 PW			SAND

BD	BULK DENSITY	PC	PLUG COMMON	PP	PLUG OF PERM SAMPLE	WE	WHOLE CORE EFFECTIVE	WS	WHOLE CORE SAT. SAMPLE
BG	BULK VOLUME GAS	PE	PLUG EFFECTIVE	PS	PLUG OF SAT. SAMPLE	WH	HORIZ MAX WHOLE CORE	WV	VERTICAL WHOLE CORE
BO	BULK VOLUME OIL	PG	PORE SPACE GAS	PV	VERTICAL PLUG	WO	WEIGHT BASE OIL	WW	WEIGHT BASE WATER
BW	BULK VOLUME WATER	PH	HORIZONTAL PLUG	PW	PORE SPACE WATER	WP	WHOLE CORE PERM SAMPLE	9H	HORIZONTAL 90 DEGREES
GD	GRAIN DENSITY	PO	PORE SPACE OIL	WC	WHOLE CORE COMMON	WR	RADIAL WHOLE CORE		

EXHIBIT NO. 11

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 31-6 Unit No. 16
Basin Dakota Field
SE/SW, Sec. 33, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7904.5-7905	.5	0.02
7905-7906	1	0.02
7906-7907	1	< 0.01
7907-7908	1	< 0.01
7908-7909	1	0.06
7909-7910	1	0.01
7910-7911	1	0.01
7911-7912	1	< 0.01
7912-7913	1	< 0.01
7913-7914	1	< 0.01
7914-7915	1	< 0.01
7915-7916	1	< 0.01
7916-7917	1	< 0.01
7917-7918	1	< 0.01
7939-7940	1	< 0.01
7940-7941	1	< 0.01
7941-7942	1	0.01
7942-7943	1	0.02
7957-7958	1	< 0.01
7958-7959	1	< 0.01
7959-7960	1	0.01
7960-7961	1	0.01
7961-7962	1	0.02
7962-7963	1	0.01
7963-7964	1	0.01
7964-7965	1	0.01
7965-7966	1	0.01
7966-7967	1	0.01
7967-7968	1	0.05
7978-7979	1	0.01
7979-7980	1	< 0.01
7980-7981	1	< 0.01
7981-7982	1	0.02
7982-7983	1	0.04
7983-7984	1	0.07
7989-7990	1	< 0.01
7990-7991	1	< 0.01
7991-7992	1	0.02
8005-8006	1	0.07
8006-8007	1	0.01
8007-8008	1	0.01
8008-8009	1	< 0.01
8009-8010	1	< 0.01
8014-8015	1	0.28
8015-8016	1	0.23
8016-8017	1	0.54
8017-8018	1	0.06

San Juan 31-6 Unit No. 16, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8022-8023	1	< 0.01
8023-8024	1	< 0.01
8024-8025	1	< 0.01
8025-8026	1	< 0.01
8029-8030	1	0.04
8030-8031	1	0.22
8031-8032	1	0.28
8032-8033	1	0.43
8033-8034	1	0.08
8034-8035	1	0.04
8035-8036	1	0.05
8036-8037	1	0.07
8037-8038	1	< 0.01
8038-8039	1	0.14
8039-8040	1	0.35
8040-8041	1	< 0.01
TOTAL	62.5	3.60

Avg. K = $\frac{3.60}{62.5}$ = 0.058 md

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

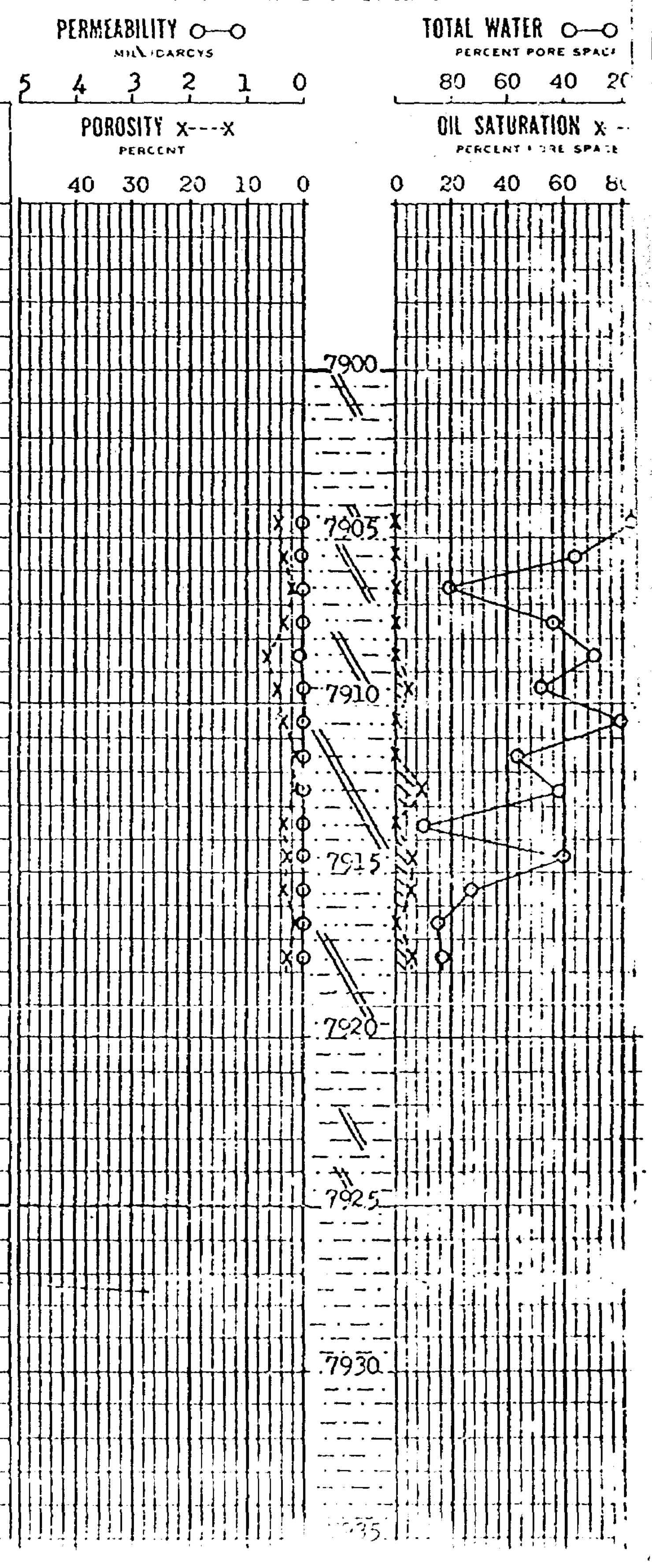
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 7/18/59 FILE NO. RP-3-1037
WELL SAN JUAN 31-6 NO. 16-33 DATE OFF 7/22/59 ENGRS ENGLISH
FIELD WILDCAT (BLANCO MESA VERDE DAKOTA) FORMATION DAKOTA ELEV. 6499' DF
COUNTY RIO ARRIBA STATE NEW MEX. DRLG. FLD. OIL EMULSION MUD CORES DIAMOND
LOCATION SEC. 33-T31N-R6W REMARKS SAMPLED BY REPRESENTATIVE OF CLIENT.

SAND | LIMESTONE | CONGLOMERATE | CHERT
SHALE | DOLOMITE | VERTICAL FRACTURE

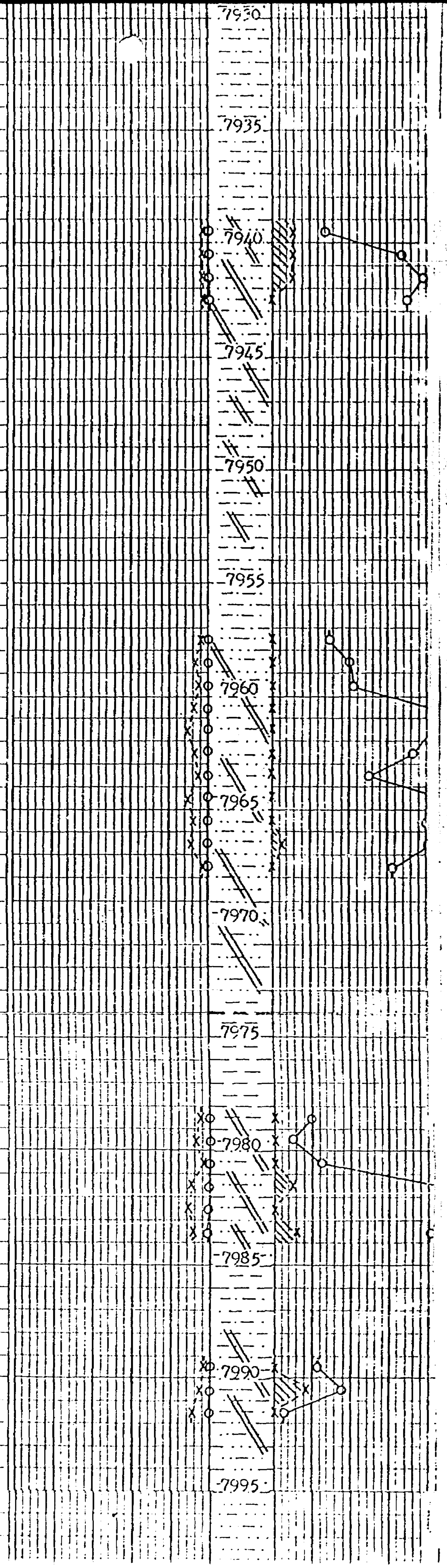
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	TOTAL WATER		PROD.
1	7904½-05	0.02	4.7	0.0	17.0		
2	05-06	0.02	3.8	0.0	36.8		
3	06-07	<0.01	2.1	0.0	81.0		
4	07-08	<0.01	3.6	0.0	44.5		
5	08-09	0.06	6.3	0.0	30.4		
6	09-10	0.01	4.5	4.4	48.8		
7	10-11	0.01	3.7	0.0	21.6		
8	11-12	<0.01	1.4	0.0	57.2		
9	12-13	<0.01	1.9	10.5	42.2		
10	13-14	<0.01	3.7	0.0	89.2		
11	14-15	<0.01	3.0	6.7	40.0		
12	15-16	<0.01	3.8	5.3	73.7		
13	16-17	<0.01	1.4	0.0	85.6		
14	17-18	<0.01	3.0	6.7	83.4		

COMPLETION COREGRAPH



15	7939-40	<0.01	1.8	11.2	72.1
16	40-41	<0.01	1.8	11.2	33.3
17	41-42	0.01	1.8	11.2	22.2
18	42-43	0.02	1.3	0.0	30.8
19	7957-58	<0.01	2.0	0.0	70.0
20	58-59	<0.01	3.3	0.0	60.6
21	59-60	0.01	2.4	0.0	58.3
22	60-61	0.01	3.8	0.0	15.8
23	61-62	0.02	5.6	0.0	17.9
24	62-63	0.01	3.7	0.0	27.0
25	63-64	0.01	2.8	0.0	50.0
26	64-65	0.01	5.4	0.0	11.1
27	65-66	0.01	3.9	0.0	20.5
28	66-67	0.01	4.1	4.9	19.5
29	67-68	0.05	1.6	0.0	37.4
30	7978-79	0.01	2.6	0.0	80.7
31	79-80	<0.01	3.7	0.0	89.2
32	80-81	<0.01	1.6	0.0	75.0
33	81-82	0.02	4.6	10.9	8.7
34	82-83	0.04	5.3	0.0	7.5
35	83-84	0.07	4.2	11.9	19.0
36	7989-90	<0.01	1.8	0.0	77.7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6



36	7989-90	<0.01	1.8	0.0	7.7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6
39	8005-06	0.07	1.0	0.0	40.0
40	06-07	0.01	1.2	0.0	58.2
41	07-08	0.01	0.9	0.0	66.6
42	08-09	<0.01	1.8	0.0	94.4
43	09-10	<0.01	1.8	0.0	94.4
44	8012-13	<0.01	3.6	5.5	80.6
45	8014-15	0.28	6.9	0.0	14.5
46	15-16	0.23	9.1	0.0	19.8
47	16-17	0.54	6.7	0.0	32.8
48	17-18	0.06	4.0	0.0	32.5
49	8022-23	<0.01	2.9	6.9	89.8
50	23-24	<0.01	3.2	15.6	81.3
51	24-25	<0.01	3.6	0.0	94.5
52	25-26	<0.01	5.2	0.0	90.4
53	8029-30	0.04	2.7	7.4	14.8
54	30-31	0.22	4.1	0.0	14.6
55	31-32	0.28	3.8	5.3	44.7
56	32-33	0.43	5.0	0.0	12.0
57	33-34	0.08	4.8	10.4	35.4
58	34-35	0.04	5.0	0.0	20.0
59	35-36	0.05	7.7	6.5	26.0
60	36-37	0.07	8.3	2.4	19.3
61	37-38	<0.01	7.6	2.6	21.1
62	38-39	0.14	6.1	3.3	26.3
63	39-40	0.35	6.2	0.0	19.3
64	8040-41	<0.01	7.4	0.0	21.6

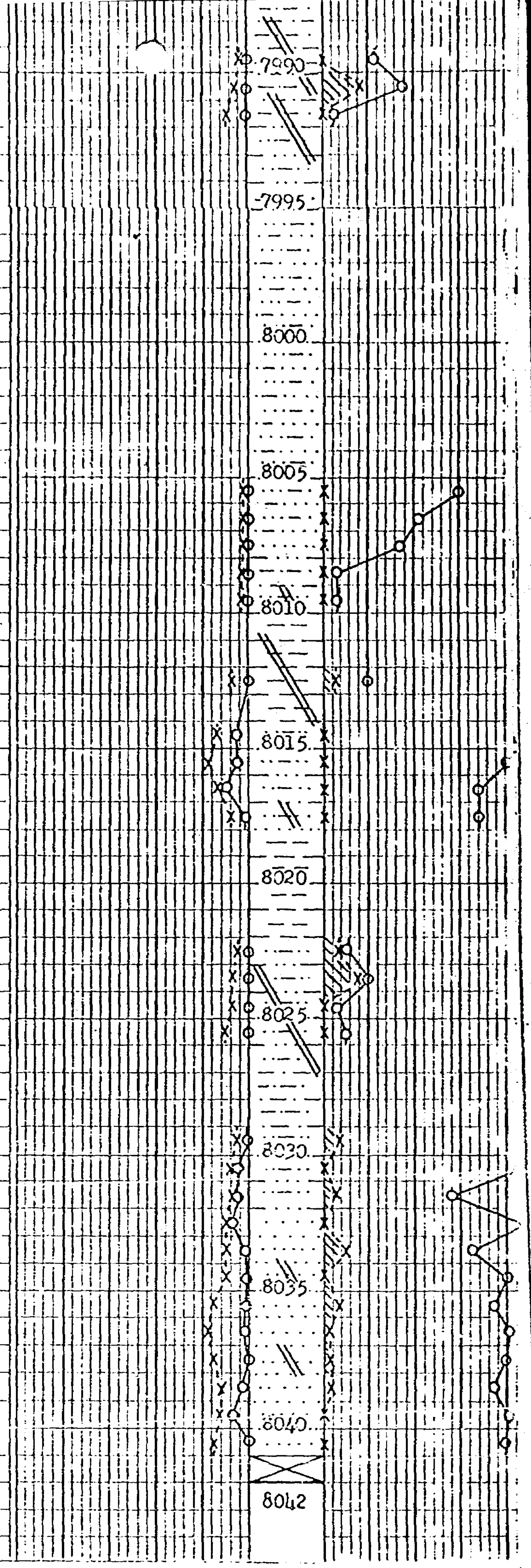


EXHIBIT NO. 12

Company: Blackwood & Nichols, Ltd.
Well: Northeast Blanco Unit No. 1
Basin Dakota Field
SE/NE, Sec. 27, T31N, R7W
San Juan County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7831-7832	1	0.01
7832-7833	1	0.01
7833-7834	1	0.01
7834-7835	1	0.01
7835-7836	1	0.01
7836-7837	1	0.01
7837-7838	1	0.01
7838-7839	1	0.01
7839-7840	1	0.01
7840-7841	1	0.01
7841-7842	1	0.01
7842-7843	1	0.01
7843-7844	1	1.50
TOTAL	13	1.62

$$\text{Avg. K} = \frac{1.62}{13} = \underline{0.125 \text{ md}}$$

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 12
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

CORE DESCRIPTIONS

<u>CORE #1</u> 6990-7039. Recovered 21' blk. shale, bottom 6' sli sandy.

<u>CORE #2</u> 7039-7042. Core jammed in bbl. Recovered 2' blk shale.

<u>CORE #3</u> 7042-7045½. Core jammed in bbl. Recovered 3' blk shale.

<u>CORE #4</u> 7800-7830. Recovered 25 1/2'.

1. shale, gry-blk, platy, sli sandy, micaceous, tr coal
2. sand, gry, vfg, calc, sli silty, scattered mica., dnse
3. shale, blk, micaceous, w/scattered sand lenses, 15% sand
4. sand, gry, vfg, calc, very silty, shale stringers, abdt mica, dnse, tite.
5. same
6. same, 20% blk shale
7. shale and sand in alternating layers, predominately shale
8. shale, blk, sli sandy, calc, micaceous
9. same, w/pearly pelecypod frags
10. same
11. same
12. same
13. same
14. same, concentric fractures parallel to bedding
15. limestone, buff-brn, dnse, silic, crypto-xln, horizontal fractures
16. shale, blk, sli sandy, micaceous
17. same, concentric fractures parallel to bedding
18. same, no fractures
19. shale and sand in alternating layers, predom. shale
20. shale and sand in alternating layers, predom. sand
21. sand, gry-wh, fg, hard, dnse, scattered intergranular poro
22. same, sli silty, w/horizontal fractures
23. same, shaley (40%), micaceous
24. shale, blk, micaceous (75%); sand (25%)
25. sand, gry, fg, hard, micaceous, w/abdt pyrite
26. same (60%); shale (40%)

<u>CORE #5</u> 7830-7831. No recovery.

<u>CORE #6</u> 7831-7844. Full recovery.

1. sand, gry-wh, fg, hard horiz. frac, tr fair intergranular poro
2. same, w/thin shale partings, tr fair poro
3. same, no frac, tr fair poro
4. same, sli silty, tr fair poro
5. same
6. same, fair poro
7. same, tr fair poro
8. same
9. same

10. same
11. same, w/thin shale partings
12. same, tr fair poro
13. same, shale (20%), tr poro

CORE 27 7844-7844. Full recovery.
1. sand, gry-wh, fg, hard, tr intergranular poro
2. same, w/scat shale partings and horiz frac
3. same
4. same

---0---

ABBREVIATIONS USED IN SAMPLE & CORE DESCRIPTION

A - angular
abdt - abundant
bent - bentonite (itic)
blk - black
brn - brown
calc - calcareous
dnse - dense
fg - fine grained
foss - fossiliferous
frac - fractured
frag - fragment(s)
fx - finely crystalline
glau - glauconite(ic)
grn - green
gry - gray
horiz - horizontal
IGR - intergranular
incl - inclusions
lg - large grained
ls - limestone
mg - medium grained
poro - porosity
pyr - pyrite
qtzitic - quartzitic
R - rounded
SA - subangular
scat - scattered
sdy - sandy
sh - shale
silic - siliceous
sli - slight
SR - subrounded
ss - sandstone
tr - trace
V - very
vert - vertical
wh - white
xln - crystalline

CORE ANALYSIS DATA

CORE #6 - 7831-7844

SAMPLE NO.	DEPTH	PERMEABILITY MILLIDARCYS	NET POROSITY %	TOTAL POROSITY %
1	7832	0.01	4.20	4.65
2	7833	0.01	2.75	3.70
3	7834	0.01	4.10	4.42
4	7835	0.01	1.17	2.08
5	7836	0.01	1.97	2.81
6	7837	0.01	2.28	3.50
7	7838	0.01	3.08	7.80
8	7839	0.01	8.50	9.30
9	7840	0.01	7.20	7.90
10	7841	0.01	2.76	3.96
11	7842	0.01	2.65	[illegible]
12	7843	0.01	1.53	3.80
13	7844	1.50*	2.35	3.60

* This plug was taken across a natural, well bonded horizontal fracture.

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. -13
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

EXHIBIT NO. 13

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

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.[1-3] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[3] 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,[1-3] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

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

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.

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 staniless 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 realistic 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-

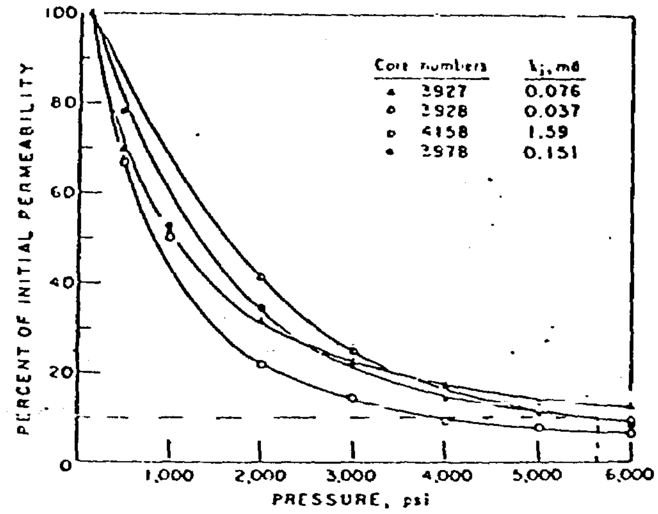


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

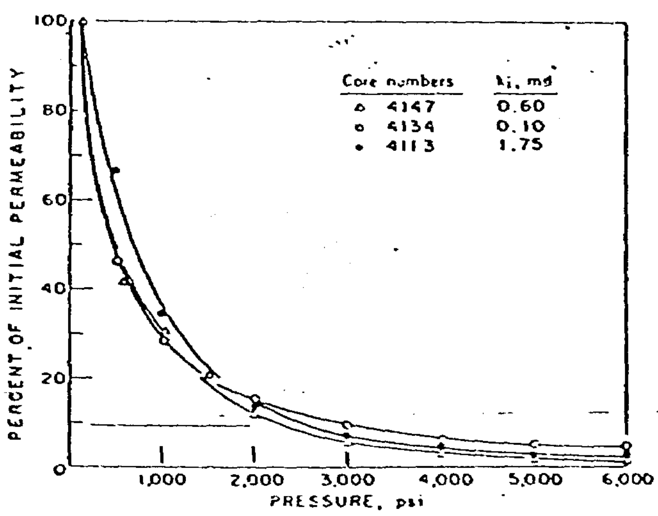


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

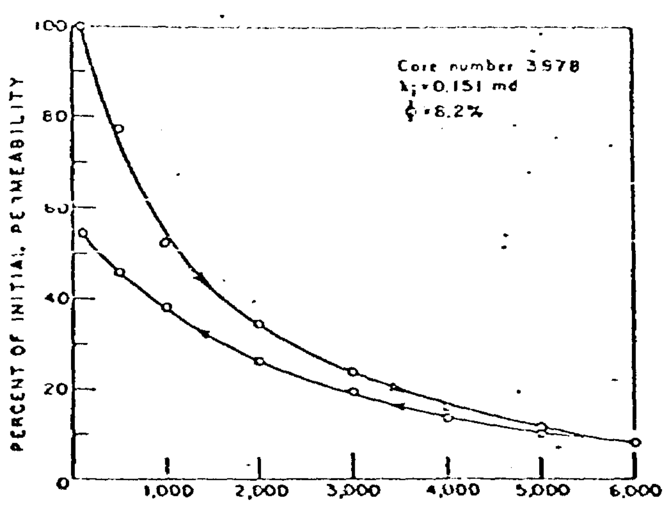


Fig. 3—Hysteresis effect at decreasing confining pressures.

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	0.038	0.067	0.051	0.032	0.025	0.022	0.018	0.016
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. 5 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	0.0025
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

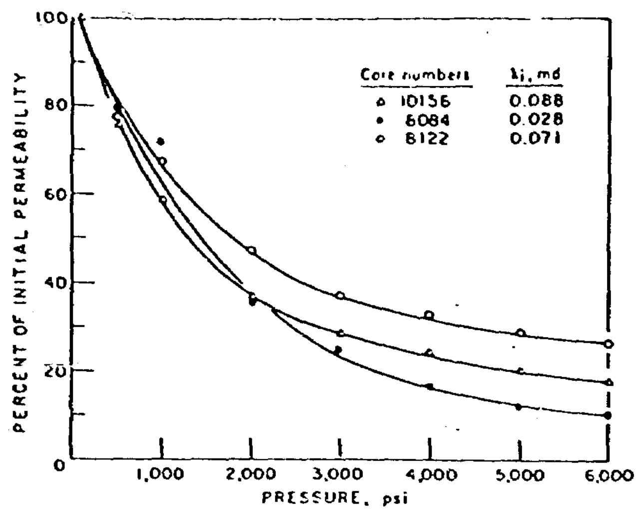


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

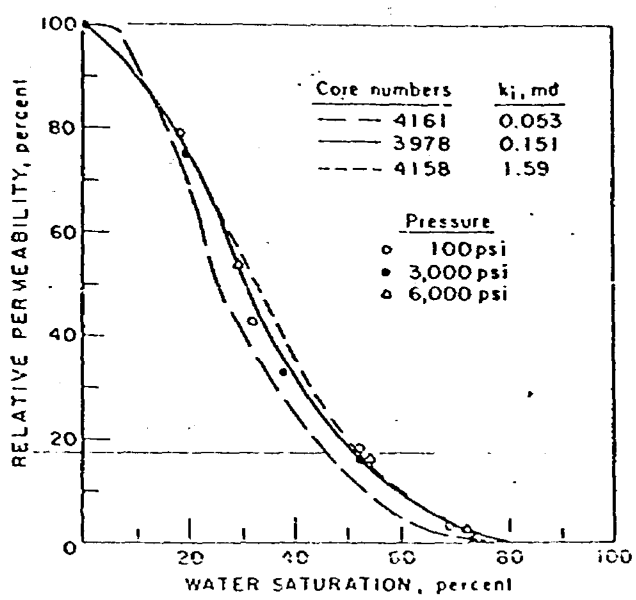


Fig. 5—Relative gas permeability of Gasbuggy cores.

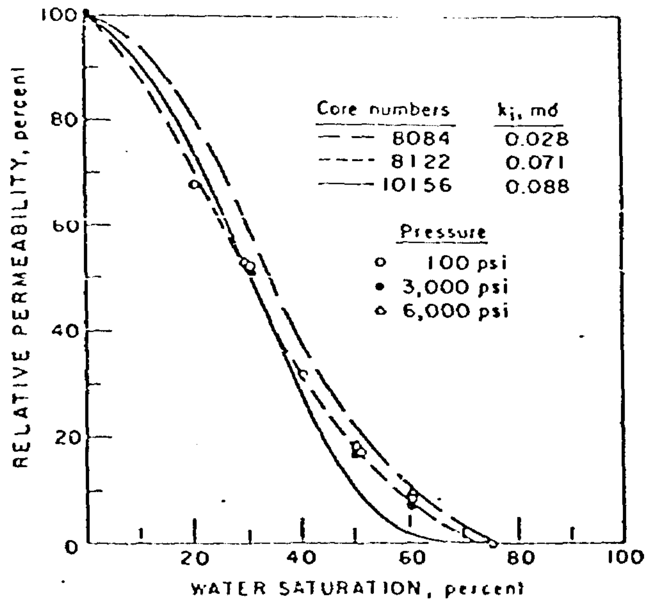


Fig. 6—Relative gas permeability of Wagon Wheel cores.

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.

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.

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.

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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JPT

EXHIBIT NO. 14

DETERMINATION OF IN SITU FORMATION PERMEABILITY FROM LABORATORY CORE ANALYSIS DATA IN THE ROSA TIGHT GAS AREA

The relationship needed to determine in situ permeability from core analysis data is published in a technical paper by Rex D. Thomas and Don C. Ward entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", which is presented as Exhibit No. 13. The authors' studies involved taking routine laboratory air permeability measurements at the normal 100 psi or less external pressures. To simulate the effect of in situ conditions, these permeability measurements were then made at external pressures ranging from 500 to 6000 psi. The results of these tests were then plotted on a graph of Percent of Initial Permeability (ratio of permeability at 100 psi to a permeability at a higher pressure) vs. Pressure.

Figure 1, on Page 121, of Exhibit No. 13, is one such graph which presents results of tests run on cores taken from the Pictured Cliffs Formation. These cores were taken from Project Gasbuggy, located in Rio Arriba County, New Mexico. Cores from the Pictured Cliffs Formation and the Dakota Formation can be expected to provide similar results due to the low permeability characteristics of both sands.

The characteristics of core 3978, presented in Figure 1, can be used to represent the core data from the Rosa Tight Gas Area. The average laboratory air permeability from the Rosa Area was 0.124 millidarcy compared to an initial laboratory core permeability for core 3978 of 0.151 millidarcy. The confining pressure due to overburden at a depth of 7950 feet in the Rosa Area is approximately 5600 psi.

Entering the graph in Figure 1 at 5600 psi results in an 90% permeability reduction between laboratory determined permeability values and in situ permeability in the Rosa Area. Applying this 90% reduction to the average laboratory permeability of 0.124 millidarcy results in an average in situ permeability of 0.012 millidarcy for the Rosa Tight Gas Area.

The water present in the reservoir also causes the in situ permeability to be less than laboratory permeability as discussed in Exhibit No. 13. However, this correction will not be used in this case.

SUMMARY OF PERMEABILITY DATA

EXHIBIT NO. 15

	WELL	SAMPLE FOOTAGE TOTAL (ft.)	LABORATORY PERMEABILITY TOTAL (md)
1.	Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	65.0	9.07
2.	El Paso Natural Gas Co. San Juan 30-5 Unit No. 28-X	87.7	11.66
3.	El Paso Natural Gas Co. San Juan 30-6 Unit No. 31	34.0	5.90
4.	Amoco Production Co. Rosa Unit No. 1	24.0	3.51
5.	Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	62.5	3.60
6.	Blackwood and Nichols Ltd. Northeast Blanco Unit No. 1	13.0	1.62
	TOTAL:	286.2	35.36

Average laboratory permeability = $\frac{35.36}{286.2}$ = 0.124 md

Average in-situ permeability (10% of laboratory) = 0.012 md

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 15
CASE NO. 7313
Submitted by McCord
Hearing Date 7-29-81

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 16
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

EXHIBIT NO. 16

ROSA TIGHT GAS AREA

Natural Production Tests
(Pitot Tube)

	OPERATOR	WELL	LOCATION	NATURAL PRODUCTION TEST DEPTH	DAKOTA DEPTH	PRODUCTION RATE NATURAL (MCFPD)	PRODUCTION RATE AFTER FRAC (MCFPD)
1.	El Paso Natural Gas Co.	San Juan 30-4 Unit No. 39	SENW 18 30-4	8615	8425	527	2506
2.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 39	SWNE 7 30-5	7822	7686	161	1703
3.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 37	NESW 8 30-5	7870	7688	666	3944
4.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 49	SWSW 9 30-5	7780	7683	TSTM	855
5.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 73	NWNE 10 30-5	8035	7919	338	2635
6.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 72	SWSW 10 30-5	7905	7790	338	2456
7.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 53	NESW 16 30-5	7820	7685	264	1209
8.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 47	NWSW 17 30-5	7930	7794	2174	1610*
9.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 38	SWNE 18 30-5	7891	7667	128	2035
10.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 48	NWNE 20 30-5	7870	7790	370	3691
11.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 38	NENW 2 30-6	7970	7832	241	2828
12.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 36	NENE 27 31-6	7890	7806	TSTM	2557
13.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 35	NENE 35 31-6	8080	7908	338	2643
14.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 31	SESE 35 31-6	7928	7796	370	3770
			14 WELL AVERAGE			423	2460
			13 WELL AVERAGE (Excluding Well No. 8)			288	2525

Natural Production Rate Limit for Tight Gas @ 7950 ft. is 336 MCFPD.

*Note after frac production rate is less than natural production rate.

EXHIBIT NO. 17

FOUR CORNERS GAS PRODUCERS
Rosa Tight Gas Area
Basin Dakota Field

Calculation of Initial Pre-Stimulation Flow Rates Using Darcy's Law

Darcy's Law: $$Qg = .703\ k\ h \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln(.61\ re/rw}$$

where:

- Qg = gas flow rate - standard cubic feet per day
- k = permeability of formation - used average in situ value of 0.012 md from core data
- h = net pay - average of 42 ft. for wells completed in the Rosa Tight Gas Area.
- Pe = bottom hole pressure at drainage radius re - average of 3330 psi. from 7 day buildup tests run in the Rosa Tight Gas Area
- Pwf = flowing bottom hole pressure - assumed to be equal to atmospheric pressure at wellbore conditions, to determine maximum flowrate (14.6 psi)
- Ug = average gas viscosity - calculated to be 0.020cp
- T = bottom hole temperature - calculated to be $667^{O}R$
- Z = average gas compressibility factor - calculated to be 0.88
- re = drainage radius for 160 acre spacing - 1320 ft.
- rw = wellvore radius - .17 ft.
- gg = gas gravity - .7 - used for calculation of Ug and Z
- Pc = pseudo critical pressure - 668 psi. - used for calculation of Ug and Z
- Tc = pseudo critical temperature - 392^{O} R - used for calculation of Ug and Z

$$Qg = .703\ (0.012)\ (42) \frac{(3330^2 - 14.6^2)}{(0.020)\ (667)\ (0.88)\ \ln(.61\ 1320/.17)}$$

Qg = 39,546 SCFGPD = 39.5 MCFGPD

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
APPLICANTS EXHIBIT NO. 17
CASE NO. 7313
Submitted by McCORD
Hearing Date 7-29-81

APPLICATION OF

FOUR CORNERS GAS PRODUCERS ASSOCIATION

FOR DESIGNATION OF THE ROSA AREA OF THE BASIN DAKOTA FIELD

AS A TIGHT GAS FORMATION

RIO ARRIBA AND SAN JUAN COUNTIES, NEW MEXICO

Case No.________________________ July 29, 1981

Prepared by:

KEVIN H. McCORD
Petroleum Engineer

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION
FOR DESIGNATION OF THE ROSA AREA OF THE
BASIN DAKOTA FIELD AS A TIGHT FORMATION,
RIO ARRIBA AND SAN JUAN COUNTIES,
NEW MEXICO

The Four Corners Gas Producers Association is applying for a portion of the Basin Dakota gas field to be designated as a tight formation under Section 107 of the Natural Gas Policy Act of 1978. The proposed Rosa Tight Gas Area is located in the northeastern portion of the San Juan Basin. The area is approximately 25 miles northeast of the town of Bloomfield in northwestern New Mexico and covers portions of Rio Arriba and San Juan counties.

Exhibit No. 1 displays the Rosa Tight Gas Area on a map of the Dakota reservoir in the San Juan Basin. The Rosa Area includes approximately 270,260 acres, described as follows:

1.	T30N-R2W	Sections 1 through 36:	All
2.	T30N-R3W	Sections 1 through 36:	All
3.	T30N-R4W	Sections 1 through 36:	All
4.	T30N-R5W	Sections 1 through 36:	All
5.	T30N-R6W	Sections 1 through 36:	All
6.	T30N-R7W	Sections 1 through 36:	All
7.	T31N-R2W	Sections 1 through 36:	All
8.	T31N-R3W	Sections 1 through 36:	All
9.	T31N-R4W	Sections 1 through 36:	All
10.	T31N-R5W	Sections 1 through 36:	All
11.	T31N-R6W	Sections 1 through 36:	All
12.	T31N-R7W	Sections 1 through 36:	All

The Dakota formation in the Rosa Area meets the criteria established in Section 107 of the Natural Gas Policy Act of 1978 to be designated a tight gas formation in that (1) the estimated average in situ gas permeability throughout the pay section is expected to be 0.1 millidarcy or less, (2) the stabilized production rates, without stimulation, at atmospheric pressure of these gas wells are not expected to exceed

the maximum allowable production rate of 336 MCFPD for an average depth of 7950 feet to the top of the Dakota formation in this area, and (3) no well drilled into the Dakota formation in this area is expected to produce more than five barrels of crude oil per day prior to stimulation.

Exhibit No. 2 is a Dakota formation completion and production map of the proposed Rosa Tight Gas Area. The production figures presented for each producing well are initial potential, date of initial potential, average daily production for 1980, and January 1, 1981 cumulative production of gas and oil. Exhibit No. 2 also presents completion and production data from wells surrounding the proposed tight gas area. The Rosa Tight Gas Area contains 53 producing Dakota formation gas wells, while 14 wells in this area are abandoned in the Dakota at this time. A list of these wells and their production figures is presented as Exhibit No. 3. Examination of these figures indicate that these Dakota wells have not produced great quantities of natural gas, suggesting that low permeability reservoir rock could be present in the area.

Exhibit No. 4 is a type log of a Dakota well found in the Rosa Tight Gas Area. This log is from the Northwest Pipeline Corporation Rosa Unit No. 68 well, found in section 17, T31N, R5W. This well is in the north central section of the Rosa Tight Gas Area. The type log shows the entire Greenhorn and Dakota formations and part of the Mancos and Morrison formations. The type log shown is in a part of the Rosa Tight Gas Area which has exhibited better producing characteristics than the remainder of the area. Wells in remaining sections of the Rosa Area would be expected to have the same or poorer log characteristics than this type log.

The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 400 feet below the base of the Greenhorn. The formations covered in this 400 feet are the Graneros Shale, Dakota Sandstone, and Morrison formations. The Dakota formation is productive in this area, while the Morrison formation is generally water bearing. Sands in the Graneros Shale are not adequately developed in this area to be productive.

The Dakota formation has an average depth of 7950 feet in the Rosa Area, and has approximately 250 feet of gross thickness. The Dakota sandstone formation is Late Cretaceous in age with deposition occurring under both

marine and nonmarine conditions. The Dakota sandstone is the basal sequence of the southwesterly transgressing Cretaceous Sea.

The Upper Dakota sand consists of barrier beach deposits about 40 to 60 feet thick, composed of fine grained, quartz-rich sandstones characterized by an increase in grain size upward and low angle crossbedding. The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones, and sandstones. This unit represented a lagoonal type environment. The basal Dakota was deposited by a system of meandering streams creating deposits of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstones. The basal unit of Cretaceous strata in the Four Corners Area is the Burro Canyon formation. This formation was deposited in a braided stream system and is sometimes considered part of the Dakota formation. An unconformity exists between the Burro Canyon formation and the Morrison formation represented by a sharp erosional contact between the two formations.

Overall, the Dakota sand has a porosity range from 1/2 to 11-1/2% in the Rosa Area, with the average pay porosity being 4%. Silt and clay sized matrix material is present throughout the Dakota sand sequence and represents a significant portion of the bulk rock composition. This matrix material reduces the effective permeability of the formation, making it difficult to produce.

Exhibit No. 5 and 6 are log cross sections through the Rosa Area showing the continuity of the Dakota formation using the base of the Greenhorn formation for a datum line.

Permeability

The Dakota formation in the San Juan Basin is dependent on stimulation techniques to be commercially productive due to the low permeability of the reservoir rock. The Dakota in situ permeability in the Rosa Tight Gas Area is found to be less than the 0.1 millidarcy permeability cutoff used for tight gas determination. The in situ permeability for this area was calculated using data from six Dakota core analysis and was averaged to be 0.012 millidarcy.

Exhibit Nos. 7 through 12 present core analysis data used to determine the average laboratory permeability to air for Dakota formation pay zones in this area. The exhibits contain the actual core analysis reports plus summary

tables showing the analysis of cores taken from only the productive portion of the Dakota formation for each well. The cored intervals chosen for permeability averaging were determined by log examination of the interval cored for each well. Only cored intervals of sand with more than 10 ohms resistivity appearing on the Induction Resistivity log of the well were used for permeability averaging. This 10 ohms resistivity cutoff represents the average resistivity shown by the shale sections on the logs, Values less than this cutoff were not considered to be pay zones. The average laboratory permeability to air determined for the Rosa Area in this manner was 0.124 millidarcy. The actual in situ permeability of the formation is less than this laboratory determined value mainly due to the confining pressures found in the Basin Dakota reservoir.

Exhibit No. 13 presents a technical paper intitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores" written by Rex D. Thomas and Don C. Ward of the U. S. Bureau of Mines. This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs. Exhibit No. 14 explains how in situ permeability is calculated from the core analysis using the technical paper presented.

Exhibit 15 is a summary of all laboratory core analysis results, for the Rosa Tight Gas Area. An average in situ permeability value of 0.012 millidarcy was calculated from the average laboratory permeability value of 0.124 md for the Rosa Area. This in situ permeability value is well below the 0.1 millidarcy tight gas cutoff. These permeability measurements substantiate that the Dakota formation is very tight in this area and must be stimulated to obtain commercial gas production.

Stabilized Unstimulated Gas Production Rate

Obtaining stabilized unstimulated gas production rates for Dakota wells is not a standard procedure used by companies when completing their wells in the San Juan Basin. Past experience has shown that these low permeability Dakota wells must be stimulated to obtain commercial production. However, some wells drilled in the Rosa Tight Gas Area were drilled with gas as a circulation medium through the Dakota formation. This drilling procedure enables unstimulated natural gas from the Dakota formation to rise to the

surface while drilling the well..

Unstimulated natural production tests can be taken while drilling with natural gas when the gas used for circulation is shut off and the pipe rams closed on the blowout preventer stack. This enables the injected gas to blow down through a bleedoff line to the reserve pit. After injection gas has had sufficient time to return to the surface, any further gas production through this line should be unstimulated gas production from the well. A gas measuring device, such as a pitot tube, placed in the center of the natural gas production stream is used to measure the natural gas flow rate from the well. A pitot tube measures the impact pressure of the gas flow rate which is used to determine the velocity of the gas. This gas velocity, combined with the known area of the blowoff line is used to calculate the flowrate of gas through the line. Natural unstimulated gas production tests performed in this manner were found for 14 wells in the Rosa Area.

The results of these unstimulated gas production tests are presented in Exhibit 16. These gas flowrates range from rates too small to measure to 2174 MCF of natural gas per day. The average unstimulated gas production rate is 423 MCFGPD. This value is larger than the 336 MCFGPD limit for tight gas at an average depth of 7950 feet. On an individual well basis, 6 wells meet the unstimulated natural production requirement, with 3 wells just at the limit, and 5 wells being over the 336 MCFGPD limit.

Testing natural gas wells in this manner is not very accurate, but it can give the tester some idea if a well will be gas productive or not. The exact nature of these tests have many factors which leave their results questionable:

(1) The Mesa Verde formation is also productive in the Rosa Tight gas area. While the Dakota formation is open to flow to the surface during the natural flow test, the Mesa Verde can also be producing at the same time. There is no way to seperate the production from each zone using a natural production test conducted in this manner.

(2) The length of these unstimulated production tests are not long enough to establish a stabilized production rate. This length of test can by no means be considered to be a stabilized production test of the well's productivity.

(3) The natural gas injected into the well for circulating purposes can also cause erroneous results if this gas is still returning to the surface while the test is being taken.

It is reasonable to assume that the three test uncertainties presented above could all contribute to make unstimulated production tests performed in this manner report erroneously high production rates. This assumption is

supported by well production data presented in Exhibit 16.

The well listed as number 8, the Northwest Pipeline Corporation San Juan 30-5 Unit No. 47 well shows an unstimulated natural gas production rate of 2174 MCFGPD. After fracturing, the initial production for this well was 1610 MCFGPD. The initial potential for a well is calculated from a 3 hour flow test following a 7 day pressure buildup, which is a more controlled and accurate test than the pitot tube test. This, combined with the fact that an after frac production test should definitely not be lower than the unstimulated production test, indicates the unstimulated production test is probably in error.

Exhibit 16 also presents a 13 well average unstimulated production rate which excludes the erroneous rate found for the San Juan 30-5 Unit No. 47 well. This 13 well average rate is 288 MCFGPD, which is below the 336 MCFGPD rate limit for tight gas determination in the Rosa Area. Due to the uncertain nature of the unstimulated production rate testing process, this 288 MCFGPD production rate, while below tight gas guidelines, is still thought to be higher than the actual average unstimulated gas production rate for the area.

In order to test the validity of this natural production figure, Darcy's Law was used to calculate an unstimulated gas flow rate using the average in situ permeability value of 0.012 millidarcy calculated for the Dakota formation in this area from core analysis study. Exhibit No. 17 presents this calculation and shows that an initial unstimulated gas flow rate of 39.5 MCFGPD is associated with the average in situ permeability of 0.012 millidarcy for the Rosa Area.

The calculated unstimulated gas production rate and the average actual unstimulated gas production rate (excluding the erroneous production rate mentioned previously) are both less than the 336 MCFGPD limit for a tight gas reservoir in the Rosa Area. As a result of these calculations, the unstimulated natural gas production rate from the Dakota formation in the Rosa Area is not expected to exceed 336 MCF of gas per day.

Stabilized Unstimulated Oil Production Rate

The Natural gas produced from the Rosa Tight Gas area is virtually dry gas, having very little, if any, oil or condensate production associated with it. Exhibits No. 2 and 3 show that only one well, the Northwest Pipeline

Corporation Rosa Unit No. 56, has reported any oil production associated with its' gas production. This well has only produced 26 barrels of oil since 1976. These dry gas production figures indicate that no well drilled in the Rosa Tight Gas Area is expected to produce. without stimulation, more than five barrels of crude oil per day.

Fresh Water Protection

Existing State and Federal regulations will assure that development of the Dakota formation will not adversely affect or impair any fresh water acquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Regulations require that casing programs be designed to seal off potential water bearing formations from oil and gas producing formations. These fresh water zones exist from the surface to the base of the Ojo Alamo formation. The Ojo Alamo depth averages 2385 feet in the proposed Rosa Tight Gas Area.

Most wells drilled in the Rosa Area are drilled with natural mud to an average depth of 3700 feet. After intermediate casing is set, the remainder of the well is drilled with natural gas. Neither the natural mud or gas will contaminate any fresh water zone.

Normal casing designs in the Rosa Area consist of 9 5/8" or 10 3/4" O. D. surface casing being set from the surface to an average depth of 3700 feet. The cementing of the intermediate casing includes enough cement to cover formations to a depth above the Ojo Alamo formation. The cement covers the Pictured Cliffs, Fruitland, and Kirtland formations which are possible oil and gas bearing formations throughout the area. The production casing is cemented from total depth to a depth above the Mesa Verde formation, or to a point approximately 3000 feet above total depth. This cement covers the Dakota, Gallup, and Mesa Verde which are possible oil and gas bearing formations. A temperature survey is run after cementing the production casing to assure that all necessary zones are covered with cement. Therefore, all oil, gas and water bearing formations in this area are isolated from each other by cement and casing. The major water aquifer in the area, the Ojo Alamo formation, as well as the Pictured Cliffs, Fruitland, and Kirtland formations

is covered by cement and two strings of casing to protect them from contamination with other formations.

Stimulation of the Dakota formation involves large fracture treatments, usually consisting of a one or two percent potassium chloride water base that will not harm a fresh water aquifer. Fresh water protection is adequate even with these large stimulation treatments due to zone isolation caused by cementation. The large distance of over 5500 feet between the Dakota formation and the Ojo Alamo fresh water acquifer is additional insurance that no existing fresh water zone will be contaminated by stimulation of Dakota wells in this area.

Therefore, New Mexico and Federal regulations will protect any fresh water supply that may be affected by drilling, completing and producing the Dakota formation in the Rosa Tight Gas Area.

CONCLUSION

Evidence presented in this report substantiate the following for the Four Corners Gas Producers' proposed Rosa Tight Gas Area:

(1) The estimated average in situ gas permeability, throughout the Dakota pay section, is expected to be 0.1 millidarcy or less;

(2) For an average Dakota well depth of 7950 feet, the stabilized production rate at atmospheric pressure of wells completed for production in the Dakota formation is not expected to exceed the maximum allowable rate of 336 MCF of natural gas per day without stimulation;

(3) No well drilled into the Dakota formation in the Rosa Area is expected to produce, without stimulation, more than five barrels of crude oil per day.

The proposed Rosa Tight Gas Area meets all the specifications required as stated above, and should be designated a tight formation in the Basin Dakota pool under Section 107 of the Natural Gas Policy Act of 1978.

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan County, New Mexico, and Rio Arriba County, New Mexico.

CASE 7317

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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INDEX

EXHIBITS

MR. STAMETS: The hearing will please come to order.

We'll call at this time Case 7317.

MR. PADILLA: Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, Santa Fe, New Mexico, appearing on behalf of Four Corners, and I have one witness.

We would also like to enter our appearance at this time for Gary Paulson, an attorney for Amoco out of Denver.

MR. STAMETS: Any other appearances in this case?

MR. KELLAHIN: If the Examiner please, I'm Tom Kellahin, Santa Fe, New Mexico, appearing in association with Mr. Larry Pain, an attorney for Phillips Petroleum Company.

MR. STAMETS: Any other appearances?

MR. PAULSON: Yes, sir, Gary Paulson Amoco Production Company, appearing in association with Mr. Carr.

We do have a supporting statement to make on behalf of the application.

MR. STAMETS: Does anyone else have an appearance? Any other witnesses in this case?

I'd like to have the witness stand and be sworn at this time, please.

(Witness sworn.)

KEVIN H. McCORD

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

DIRECT EXAMINATION

BY MR. CARR:

Q Will you state your name and place of residence?

A My name is Kevin H. McCord and I live in Farmington, New Mexico.

Q By whom are you employed and in what capacity?

A I am self-employed. I'm a self-employed petroleum engineer acting as a consultant for the Four Corners Gas Producers Association.

Q Have you previously testified before

this Commission or one of its examiners and had your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, I have.

Q. Are you familiar with the application of Four Corners Producers Association in this case?

A. Yes, I am.

Q. Are you familiar with the subject area?

A. Yes.

MR. CARR: Are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q. Mr. McCord, will you briefly state what Four Corners Gas Producers Association seeks with this application?

A. The Four Corners Gas Producers Association is applying for a portion of the Basin Dakota gas field to be designated as a tight formation under Section 107 of the Natural Gas Policy Act of 1978.

The proposed Rosa tight gas area is located in the northeastern portion of the San Juan Basin. The area is approximately 25 miles northeast of the town of Bloomfield in northwestern New Mexico, and covers portions of Rio Arriba and San Juan Counties.

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

A. I have.

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

A. Yes, they have.

Q. Will you please refer to what has been marked for identification as Applicant's Exhibit Number One and explain to Mr. Stamets what this is and what it shows?

A. Exhibit Number One displays the Rosa tight gas area on a map of the Dakota reservoir in the San Juan Basin. The Rosa area includes approximately 270,260 acres in Townships 30 and 31 North, Ranges 2 through 7 West.

Q. Will you now refer to Exhibit Two and review this for the Examiner?

A. Exhibit Number Two is a Dakota formation completion and production map of the proposed Rosa tight gas area. The production figures presented for each producing well are initial potential, date of initial potential, average daily production for 1980, and January 1, 1981 cumulative production of gas and oil.

Exhibit Number Two also presents completion and production data from wells surrounding the proposed tight gas area. The Rosa tight gas area contains 53 producing Dakota formation gas wells, while 14 wells in this area are abandoned in the Dakota at this time.

A list of these wells and their production figures is presented as Exhibit Number Three. Examination of these figures indicate that these Dakota wells have not produced great quantities of natural gas, suggesting that low permeability reservoir rock could be present in the area.

Q. Now, Mr. McCord, will you please refer to Applicant's Exhibit Number Four and review this for the Examiner?

A. Exhibit Number Four is a type log of a Dakota well found in the Rosa tight gas area. This log is from the Northwest Pipeline Corporation Rosa Unit No. 68 Well, found in Section 17, Township 31 North, Range 5 West. This well is in the north central section of the Rosa tight gas area.

The type log shows the entire Greenhorn and Dakota formations and part of the Mancos and Morrison formations.

The type log shown is in a part of the Rosa tight gas area which has exhibited better producing characteristics than the remainder of the area. Wells in the remaining sections of the Rosa area would be expected to have the same or poorer log characteristics than this type log.

Q. How is the Dakota formation defined by the Oil Conservation Division?

A. The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 400 feet below the base of the Greenhorn. The formations covered in this 400 feet are the Graneros Shale, Dakota Sandstone, and Morrison formations.

The Dakota formation is productive in this area while the Morrison formation is generally water-bearing. Sands in the Graneros Shale are not adequately developed in this area to be productive.

Q. Mr. McCord, what is the average depth of the Dakota formation in the area which is governed by this application?

A. 7950 feet.

Q. And what is the gross thickness of the formation?

A. Approximately 250 feet.

Q. Could you generally describe the geological characteristics of the Dakota?

A. It's generally, let's see here, the Dakota consists generally of barrier beach deposits about 40 to 60 feet thick. This is the Upper Dakota. Composed of fine grained, quartz rich sandstones characterized by an increase in grain size upward and low angle crossbedding.

The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones, and sandstones. This unit represented a lagoonal type environment.

The basal Dakota was deposited by a system of meandering streams creating deposits of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstones.

Q. Will you now refer to what has been marked Applicant's Five and Six and explain what these are and what they show?

A. Exhibit Numbers Five and Six are log cross sections through the Rosa area showing the continuity of the Dakota formation using the base of the Greenhorn formation for a datum line.

Q. Now, Mr. McCord, when I look at your Exhibit Number Two, is there any control in the Dakota on the east side of the subject area?

A. No, sir, there's not. There's been

very sparse drilling in that area. Only one well was drilled and that would be in Section -- or Township 30 North, Range 3 West, Section 34. A Dakota well was drilled by Sunray DX Oil Company, Jicarilla Tribal No. 1, in September of '64. It was drilled and abandoned.

Other than that there is no control to the east part of the area.

Q In your opinion is the Dakota continuous across the basin?

A. Yes, it is.

Q What is the porosity range within the area governed by the application?

A. Overall the Dakota sand has a porosity range of from 1/2 percent to 11-1/2 percent in the Rosa area, with the average pay porosity being in the neighborhood of 4 to 6 percent.

Q Is the in situ permeability cutoff in the Rosa tight gas area less than .01 millidarcy?

A. Yes, it is. The formation is dependent upon stimulation techniques to be commercially productive.

Q And have you calculated permeability for the area?

A. Yes, I have.

Q Would you please refer to Applicant's

Exhibits Seven through Twelve and review these for Mr. Stamets?

A. Okay. Exhibits Numbers Seven through Twelve present core analysis data used to determine the average laboratory permeability to air for Dakota formation pay zones in this area. The exhibits contain the actual core analysis reports, plus summary tables, showing the analysis of cores taken from only the productive portion of the Dakota formation for each well. The cored intervals chosen for permeability averaging were determined by log examination of the interval cored for each well. Only cored intervals of sand with more than 10 ohms resistivity appearing on the induction resistivity log of the well were used for permeability averaging. This 10 ohms resistivity cutoff represents the average resistivity shown by the shale sections on the logs. Values less than this cutoff were not considered to be pay zones.

The average laboratory permeability to air determined for the Rosa area in this manner was 0.124 millidarcy. The actual in situ permeability of the formation is less than this laboratory determined value, mainly due to the confining pressures found in the Basin Dakota reservoir.

Q. Will you now refer to and identify what you have marked Applicant's Exhibit Thirteen?

A. Exhibit Number Thirteen presents a

technical paper entitled Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores, which was written by Rex D. Thomas and Don C. Ward of the U. S. Bureau of Mines.

This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs.

Exhibit Number Fourteen explains how in situ permeability is calculated from the core analysis, using the technical paper presented.

Q. Will you now refer to your Exhibit Number Fifteen and explain this exhibit?

A. Exhibit Fifteen is a summary of all laboratory core analysis results for the Rosa tight gas area. An average in situ permeability value of 0.012 millidarcy was calculated from the average laboratory permeability value of 0.124 millidarcy for the Rosa area. This in situ permeability value is well below the 0.1 millidarcy tight gas cutoff. These permeability measurements substantiate that the Dakota formation is very tight in this area and must be stimulated to obtain commercial gas production.

Q. Mr. McCord, can gas be produced in commercial quantities from the formation in the subject area without stimulation?

A. No, it cannot.

Q. Now I believe you stated that the average depth of the Dakota in this area was 7950 feet. What is the maximum stabilized production rate against atmospheric pressure allowed for wells in the subject area in this depth by the Oil Conservation Division rules?

A. 336 Mcf of gas per day.

Q. Have you obtained stabilized unstimulated gas production rates for Dakota wells in the area?

A. Yes, I have. Obtaining stabilized unstimulated gas production rates for Dakota Wells is not a standard procedure used by companies when completing their wells in the San Juan Basin. Past experience has shown that these lower permeability Dakota wells must be stimulated to obtain commercial production; however, some wells drilled in the Rosa tight gas area were drilled with gas as a circulation medium through the Dakota formation. This drilling procedure enables unstimulated natural gas from the Dakota formation to rise to the surface while drilling the well. Unstimulated natural production tests can be taken while drilling with natural gas when the gas used for circulation is shut off and the pipe rams closed on the blowout preventer stack. This enables the injected gas to go down through a bleedoff line to the reserve pit.

After injection gas has sufficient time to return to the surface any further gas production through this line should be unstimulated gas production from the well. A gas measuring device, such as a pitot tube placed in the center of the natural gas production stream, is used to measure the natural gas flow rate from the well. A pitot tube measures the impact pressure of the gas flow rate, which is used to determine the velocity of the gas. This gas velocity combined with the known area of the blowoff line is used to calculate the flow rate of the gas through the line.

Natural unstimulated gas production tests performed in this manner were found for 14 wells in the Rosa area. The results of these unstimulated gas production tests are presented in Exhibit Sixteen. These gas flow rates range from rates too small to measure to 2174 Mcf of natural gas per day. The average unstimulated gas production rate is 423 Mcf per day. This value is larger than the 336 Mcf per day limit for tight gas at an average depth of 7950 feet. On an individual well basis six wells meet the unstimulated natural production requirement with three wells just at the limit and five wells being over the 336 Mcf per day limit.

Testing natural gas wells in this manner is not very accurate but it can give the tester some idea if a well will be gas productive or not. The exact nature of these tests have many factors which leave their results questionable.

The Mesaverde formation is also productive in the tight gas -- in the Rosa tight gas area. While the Dakota formation is open to flow to the surface during the natural flow test, the overlying Mesaverde can also be producing at the same time. There is no way to separate the production from each zone using a natural production test conducted in this manner.

Also, the length of these unstimulated production tests are not long enough to establish a stabilized production rate. This length of test can by no means be considered to be a stabilized production test of the well's productivity.

Also, the natural gas injected into the well for circulating purposes can also cause erroneous results if this gas is still returning to the surface while the test is being taken.

It is reasonable to assume that the three test uncertainties presented could all contribute to make unstimulated production tests performed in this manner report erroneously high production rates. This assumption is supported by well production data presented in Exhibit Sixteen. The well listed as number eight, the Northwest

Pipeline Corporation San Juan 30-5 Unit No. 47 Well, shows an unstimulated natural gas production rate of 2174 Mcf per day. After fracturing, the initial production for this well is 1610 Mcf per day. The initial potential for a well is calculated from a 3-hour flow test following a 7-day pressure build-up, which is a more controlled and accurate test than the pitot tube test.

This, combined with the fact that an after-frac production test should definitely not be lower than the unstimulated production test, indicates the unstimulated production test is probably in error.

Exhibit Sixteen also presents a 13 well average unstimulated production rate, which includes the erroneous rate found -- excuse me, whic excludes the erroneous rate found for the San Juan 30-5 Unit No. 47 Well. This 13 well average rate is 288 Mcf per day, which is below the 336 Mcf per day rate limit for tight gas determination in the Rosa area.

Due to the uncertain nature of the unstimulated production rate testing process, this 288 Mcf per day production rate, while being below the tight gas guideline, is still thought to be higher than the actual average unstimulated gas production rate for the area.

Q. Have you calculated the unstimulated gas flow rate using the in situ permeability value of .012 millidarcies?

A. Yes, I have. In order to test the validity of this natural production figure, Darcy's Law was used to calculate an unstimulated gas flow rate using the average in situ permeability value of 0.012 millidarcy calculated for the Dakota formation in this area from core analysis study.

Exhibit Number Seventeen presents this calculation and shows that an initial unstimulated gas flow rate of 39.5 Mcf per day is associated with the average in situ permeability of 0.012 millidarcy for the Rosa area.

The calculated unstimulated gas production rate and the average actual unstimulated gas production rate, excluding the erroneous production rate mentioned previously, are both less than the 336 Mcf per day limit for a tight gas reservoir in the Rosa area. As a result of these calculations the unstimulated natural gas production rate from the Dakota formation in the Rosa area is not expected to exceed 336 Mcf of gas per day.

Q. Do you have any unstimulated oil production figures for this area?

A. Yes. The natural gas produced from the Rosa tight gas area is virtually dry gas, having very little, if any, oil or condensate production associated with it.

Exhibits Number Two and Three show that only one well, the natural -- excuse me, the Northwest Pipeline Corporation Rosa Unit No. 56, has reported any oil production associated with its gas production.

MR. STAMETS: What's the location of that well?

A. Okay, Section 35, 31, 5.

MR. STAMETS: Okay.

A. This well has only produced 26 barrels of oil since 1976. These dry gas production figures indicate that no well drilled in the Rosa tight gas area is expected to produce without stimulation more than 5 barrels of crude oil per day.

Q. Mr. McCord, will the production of hydrocarbons from the subject area impair fresh water supplies in this area?

A. No, they will not.

Existing State and Federal regulations will assure that development of a Dakota formation will not adversely affect or impair any fresh water aquifers that are being used or expected to be used in the foreseeable future for domestic or agricultural water supplies. Regulations require that casing programs be designed to seal off potential water-bearing formations from oil and gas producing formations.

These zones, these fresh water zones exist from the surface to the base of the Ojo Alamo formation. The Ojo Alamo depth averages 2385 feet in the proposed Rosa tight gas area.

Most wells drilled in the Rosa area are drilled with natural mud to an average depth of 3700 feet. After intermediate casing is set the remainder of the well is drilled with natural gas. Neither the natural mud or the gas will contaminate any fresh water zones.

Normal casing designs in the Rosa area consist of 9-5/8ths or 10-3/4 inch OD surface casing, being set from the surface to an average depth of 3700 feet. Cementing of the intermediate casing includes enough cement to cover formations to a depth above the Ojo Alamo formation. The cement covers the Pictured Cliffs, Fruitland, and Kirtland formations, which are possible oil and gas bearing formations throughout the area.

The production casing is cemented from total depth to a depth above the Mesaverde formation, or to a point approximately 3000 feet above total depth. This cement covers the Dakota, Gallup, and Mesaverde, which are possible oil and gas bearing formations. A temperature survey is run after cementing the production casing to assure that all necessary zones were covered with cement. Therefor, all oil, gas, and water bearing formations in this area are isolated from each other by cement and casing.

The major water aquifer in this area, the Ojo Alamo formation, as well as the Pictured Cliffs, Fruitland, and Kirtland formations, is covered by cement and two strings of casing to protect them from the contamination with other formations.

Stimulation of the Dakota formation involves large fracture treatments, usually consisting of one or two percent potassium chloride water base that will not harm a fresh water aquifer.

Fresh water protection is adequate even with these large stimulation treatments due to zone isolation caused by cementation. The large distance of over 5500 feet between the Dakota formation and the Ojo Alamo fresh water aquifer is additional insurance that no wells exist that -- that no existing fresh water zones will be contaminated by the stimulation of Dakota wells in the area.

Therefor, New Mexico and Federal regulations will protect any fresh water supply that may be affected by drilling, completing, and producing the Dakota formation in the Rosa tight gas area.

Q. Mr. McCord, is the price authorized by Section 107 of the Natural Gas Policy Act necessary to provide a reasonable incentive for production of natural gas from the subject formation due to the extraordinary risk for costs associated with such production?

A. Yes, it is.

Q. In your opinion is the data available to you and presented at this hearing supporting the conclusion that the entire area governed by this application qualifies for a tight formation designation under Section 107 of the Natural Gas Policy Act?

A. Yes, it does.

Q. At this time would you briefly summarize the conclusions you have reached in making a study of the subject area?

A. The estimated average in situ gas permeability throughout the Dakota pay section is expected to be 0.1 millidarcy or less for an average Dakota well depth of 7950 feet. The stabilized production rate at atmospheric pressure of these wells completed for production in the Dakota formation is not expected to exceed a maximum allowable rate of 336 Mcf of natural gas per day without stimulation. No well drilled into the Dakota formation in the Rosa area is expected to produce without stimulation more than 5 barrels of crude oil per day.

The proposed Rosa tight gas area meets

all the specifications required as stated above and should be designated a tight formation in the Basin Dakota Pool under Section 107 of the Natural Gas Policy Act of 1978.

Q Mr. McCord, has this area been approved for infill drilling?

A. Yes, it has in May of 1979.

Q. And that was by Commission Order R-1670-V?

A. Yes, I believe so.

Q. Have any infill wells been drilled in the subject area?

A. There have been a few infill wells drilled in this area after I have gathered all the data for this report. I'll point those out. They are both John Schalk wells. One would be in the southeast --

MR. STAMETS: Start out with the township and range.

A. Sure.

MR. STAMETS: It makes it a little easier to find.

A. Okay, 30, 30 North, 5 West, Section 2, southeast quarter.

The other well being in 30 North, 5 West, Section 12, I believe the northeast quarter.

These are recent wells that have been

drilled. My information on this map is May of 1981, so these are recent wells and it's my understanding have not been completed at this time.

Q. How would you characterize the development of the subject area on the original 320-acre spacing?

A. Very, very sparse development under 320 acres. I believe I calculated under the existing acreage 53 producers. This is only 6 percent of our 320-acre spacing, and to my knowledge these two Schalk wells mentioned are the only two infill wells that have been attempted in the area. I believe that might have had something to do with that man's holdings in the area more than all the economic criteria involved.

Q. Mr. McCord, in your opinion will further development of the subject area depend upon approval of this application and the resulting incentive price?

A. I think, yes, to be adequately developed this area will need the 107 price to make it economically feasible.

Q. Will you please refer to and identify what has been marked as Applicant's Exhibit Eighteen?

A. Exhibit Eighteen is a written text explaining each of the exhibits I have just presented.

Q. And this text was submitted with the

exhibits to the Commission and USGS?

A. Yes, that's correct.

Q. Were Exhibits One through Eighteen prepared by you or have you reviewed each of these exhibits and can you testify as to their accuracy?

A. Yes, I can. There were prepared by me.

Q. In your opinion will granting this application result in the production of gas that otherwise would not be produced?

A. Yes.

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

A. Yes, it will.

MR. CARR: At this time, Mr. Stamets, we would offer into evidence Applicant's Exhibits One through Eighteen.

MR. STAMETS: These exhibits will be admitted.

MR. CARR: Mr. Stamets, I've been asked to direct certain questions to Mr. McCord on behalf of the USGS and I'll be happy to do that now or at a later time, whenever you desire.

MR. STAMETS: Well, why don't you just

go ahead and do that now, Mr. Carr, and then we'll get that part out of the way.

Q. Mr. McCord, what is the basis for the boundaries of the proposed tight gas sand area designation, and is this based on geologic and/or engineering parameters?

A. The area studied, and I'd like to point out is just an area of study, I'm not trying to say that areas outside are not tight gas areas, it was assigned to me by the Four Corners Gas Producers Association.

It is my feeling that it is not based on either geologic or engineering parameters, mainly on the rights of the Association.

Q. Could you provide a structure Isopach insert map for the Dakota for the Rosa tight gas area?

A. It would be possible to supply a structure Isopach map, although I do not believe that this would show any more information than what cumulative production is shown on Figure Two. I believe this indicates that the well, the Rosa area is definitely not a very prolific area, and because of that I do not believe this information would be helpful, but if requested, we could supply this.

Q. Now, Mr. McCord, the type log for the Rosa Unit No. 68 Well, which is used as your Exhibit Number Four, indicates that four separate zones were perforated for production. In reviewing the wells presented and the two cross sections, being Exhibits Number Five and Six, in some wells more than four zones were perforated.

The question is, is this application asking for all zones in the Dakota to be designated as a tight formation or only certain zones? And for the purposes of this question, zone refers to an individual sandstone separated by shale from other sandstones.

The question is, are you asking for all of the zones in the Dakota to be designated tight formations?

A. Yes. The Four Corners Gas Producers requested that the entire Dakota section as defined 400 feet below the base of the Greenhorn be designated as a tight formation.

Q. Is this application asking for a tight sand designation for infill locations within the Rosa tight gas area, and there are certain examples given here. First, in Township 30 North, Range 5 West, Section 9, there are apparently two infill locations. Is it the request of the applicant that these be included in the tight sand designation?

A. Yes, it is.

Q. There are also two locations in Section 10 and two in 20 of Township 30 North, Range 5 West.

A. Yes, those also.

Q. In Township --

MR. STAMETS: What was the last section?

MR. CARR: Section 20. All of this first group, they are all in Township 30 North, Range 5 West.

MR. STAMETS: And there are two in there or just one?

MR. CARR: Two, according to the question.

MR. STAMETS: Infill locations in Sections 9 and 20 --

MR. CARR: And 10.

MR. STAMETS: And 10. Let me get 10 marked on my exhibit, please.

MR. CARR: All right. Now in Township 31 North, Range 5 West, one location in Section 8.

A. Okay. I believe there should be two locations in Section 8. I do not have an infill well in that location, or in that section. I believe that should be two locations, and yes, we are asking for that also.

Q. And, again, two locations in Section 11 and in Section 17?

A. Yes.

Q. And now in Township 31 North, Range 6 West, two locations in Section 27 and two locations in Section 35.

A. Yes, we ask that these be part of the application as well.

MR. STAMETS: What was the second section, please?

MR. CARR: 35.

Q. So you are asking that all infill locations within the Rosa area be included within the tight sand designation?

A. That is correct.

Q. Mr. McCord, I direct your attention now to Exhibit Number Three, and it indicated that 12 Dakota wells were drilled in 1980, and 9 Dakota wells were drilled in 1981, all at current 103 prices.

Is it no longer economical to drill wells such as those drilled in 1980 and '81 under 103 prices?

A. Yes, it would still be economical to drill some of these newer wells that were drilled in 1980 and 1981 under 103 prices if there were -- existed any good producing characteristics such as exhibits by those wells. As to the current time there are not any of this type of location available. Therefor, to continue to drill wells in this area the 107 price would be necessary to -- to substantially complete the area.

Q. Is it your answer that if there were

comparable locations in the Rosa area that the wells could be drilled at 103 prices?

A. Yes, it's my feeling they could.

Q. At this time, based on your study, you do not believe there are comparable locations?

A. I don't believe that, no.

Q. Is the 107 price necessary to have an economical well that would be similar in production potential to those drilled in 1980 and 1981?

A. Yes, it would be necessary because as we stated before there are no more wells of the calibre drilled of the ones in 1980 and '81 with -- with that calibre for 103 prices; therefor, the 107 is needed.

Also, there is no more drilling, the drilling plan for 1981 has been discontinued in this area because of the marginal economics.

Q. Mr. McCord, could you provide economic data as to the rate of return on -- showing comparison of several of the 21 wells that were drilled in 1980 and 1981, using the 103 price and contrasting that with the 107 price?

A. Yes, it is possible to provide this economic data, although in the instance of this area, there is mainly developed on 320 acres, acre spacing, and it's my understanding that economics are not required of 320-acre spacing in the Dakota.

Q. Of the 21 wells that were drilled in 1980 and '81, do you know if the economics on these wells made them attractive prospects?

A. Yes, in some of the wells they were attractive prospects under 103 prices, but it is my understanding that some of these wells drilled in '80 and '81 were demand wells. Also, some had marginal 103 economics. This is exemplified by the fact that the drilling in 1981 has been discontinued for the area because of the low profitability of these wells.

MR. CARR: I have no further questions of Mr. McCord.

MR. STAMETS: Are there other questions of the witness? Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q. How many unspud Dakota locations or non-completed Dakota wells are there in this area at this time?

A. Okay, Mr. Chavez, I have them marked on my map. Once again, the map is dated as of 5 of 81, so there have been some wells drilled since then.

In Township 31 North, Range 6 West, Section 8, Rosa No. 88, and that's in the south -- excuse me, the northwest quarter.

Q. Has it been completed or just spud?

A. To my knowledge it's either -- I don't have the information as to -- at this time what stage of progress it's in. It has been staked and is a possible location for a future well. That's really the only thing I'm sure of. That's what I have marked on the map.

Also, in 31 North, 6 West, Section 14, in the northeast quarter, the Amoco Rosa 67. It's my understanding that this well is dry in the Dakota and Amoco is possibly going to recomplete in the Mesaverde or PC in this well.

All right, in 31 North, 5 West, Section 20, the northeast one quarter, the Rosa No. 85.

In that same township and range, Section 33, southwest quarter, the Rosa No. 77.

In 31 North, 4 West, Section 7, the northeast quarter, Mitchell, the Rosa No. 81.

In Section 9 of that same township, southwest quarter, the Rosa 82 by Mitchell.

Section 12, in the northwest quarter, the Amoco Rosa No. 87.

Section 15, northeast quarter, Mitchell Rosa No. 83.

Section 23, the northeast, Rosa No. 84. That's all for that township.

Q These are staked but not completed wells?

A. The Mitchell wells I do know about. They have all been drilled. Only one well has been perforated and fraced and it is testing water at this time; no commercial gas production.

The other three wells have not been completed at this time.

All right, Township 30 North, 4 West, Section 13, Southland, the Simms Federal No. 1. That's the southeast quarter. This is drilled due to lease expiration date.

Okay, in 30 North, 5 West, I have the two Schalk infill locations, the 54-1E in Section 2, and the 57-1E in Section 12.

In Section 5, San Juan 30-5 Unit No. 79, in the northeast quarter.

Section 5, the southwest quarter, the 30-5 Unit No. 50.

Section 23, the southwest quarter, the 30-5 Unit No. 83.

Section 25, the 30-5 Unit No. 82 in the northwest quarter.

Q. Section what, I'm sorry?

A. 25. No. 82.

Q. What was that, I'm sorry?

A. That's the 30-5 Unit No. 82, the northwest quarter of 25, 30-5, okay?

Q. Okay.

A. Section 27, the southwest quarter, 30-5 Unit No. 81, and Section 36, the northeast quarter, the 30-5 Unit No. 77.

That is all the wells I have that are staked in this area as of this time.

Q. Is the drilling of these wells pending the outcome of this hearing? Or is it just pending rig availability?

A. I cannot tell you the actual answer to that. I don't know what the future plans on these wells, if any of them have been completed. I know some of them have been drilled but I would not be able to separate each one out. I've just picked them up through PI as possible locations in this area. I do not know the status of them all.

MR. CHAVEZ: That's all the questions I have.

MR. STAMETS: Are there other questions of the witness? Mr. Padilla?

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. McCord, you testified about comparable locations. What do you mean by a comparable location? Does that mean -- I think it would mean that that's a good location. Are you saying that in this area you've run out of good locations now?

A. Yes. In my talks with Phillips Petroleum Company, who is mostly in this 30-5 Unit, they have drilled most of these newer wells and from talking with these people, their feeling is that -- that all of their good drilling locations have been used up.

Q What have they based their justification for --

A. To tell you the truth, I couldn't answer that for you. That's just information they supplied to me.

Q And that's the same thing for the same calibre, same calibre, quote, same calibre of location, is that the same thing?

A. Yes. Yes.

Q Can you tell me what marginal economics are for drilling Dakota wells in this area?

A. Well, of course, Mr. Padilla, that's going to differ for any large company you're talking about, and if I said what marginal economics were, one company would call it good, one company would probably call it bad.

But I would say anything greater than a 3-year payout would be considered pretty marginal to be drilled. You just need a greater rate of return, greater return on your money than tying it up for that great period of time.

That's pretty rough, but once again, each company is going to have a different opinion of that same question.

Q. Well, how much does it cost to drill one of these wells?

A. On information supplied by Amoco, approximately $800,000 to drill and complete these wells, and approximately 20 percent of that goes to the stimulation costs. So it's a considerable amount.

Q. How much revenue would, say, a Section 103 price, can you get from a -- one of these wells located, say, in 30 North, 5 West? The newer wells.

A. Okay. I'd come up with an average ultimate production of .65 Bcf throughout the entire area. It's going to be, I would -- I would estimate that is a pretty good average for a 30-5 Unit. The actual dollars involved that that comes out to, I haven't calculated.

Q. Wouldn't you have to apply the dollar amount in order to determine whether or not you should get the incentive price?

A. To determine payout, yes. It's just a matter, I haven't -- I haven't plugged in that number to give an ultimate amount of money the wells will produce. That is how I determined a payout of approximately six years under 103 prices, taking an average decline and actual decline for the area, which is a rapid initial decline in the first year, leveling off through about year five at about a 10 percent decline rate. Using those numbers and a .65 Bcf, your payout to recover your $800,000 cost is approximately six years.

Q. Well, what's a 3-year payout? Is that on 107 prices?

A. No, a 3-year payout I mentioned to you, was my feeling, and this was only my feeling, of whether a well would be worth drilling or not.

A 6-year payout to me would be very marginal economics. You'ld be tying up your money a lot longer than need be there. You just -- you need better economics than that to be drilling these wells.

Q. This Exhibit Number Two doesn't show any wells at all in almost the entire east half of that area, except the well in the Section 34, 3 North, 3 West. That means that there have been no wells drilled with the exception of that one well that I mentioned on there.

A. No wells to the Dakota, that is -- that is correct. This would be an area that the 107 prices would virtually be a must for the exploration of. Obviously, no one has thought under 103 prices this area is worth prospecting. The 107 would -- would encourage drilling of wells in this area.

Q. Is this -- is this area unitized currently under -- do you know?

A. I don't believe it's under a unit agreement, not the farther east. Most of the -- most of the newer wells are under existing units.

Q. Is this east half area drilled in shallower formations?

A. It might possibly be but I don't have that information. I've just concentrated on Dakota wells. To my knowledge, if so, there would be very, very few wells.

Q. You don't know whether there are any Pictured Cliffs wells, Pictured Cliff wells at all in this area?

A. Not offhand I don't. I would have to check, check my PI cards to see if any were drilled.

MR. PADILLA: I believe that's all I have, Mr. Examiner.

CROSS EXAMINATION

BY MR. STAMETS:

Q. Mr. McCord, in reviewing the exhibits, apparently you have based your contention that you would expect to find permeability throughout this area less than one-tenth of a millidarcy on a number of cores that were available in the area.

A. Yes, sir, that's correct.

Q. Okay. I looked at Exhibit Number Two and identified eleven wells with potentials, I presume after stimulation, that exceeded 3-million cubic feet a day. I also noted that none of these wells happened to be a well that was cored. It seems as though the cored wells are always the poorer wells.

Is there any way of going backwards from what we have on these wells and determining the permeability?

A. Yes. The main thing being, first of all, I'd like to state that I'm sure you're aware that the initial potential is a very misleading figure on wells.

I have looked at approximately 20 wells throughout the area and have found that the first month's production from those wells is in the range of 15 to 20 percent of their IP, which indicates that their IP number is very misleading as what the wells will do against line pressure when put on line, actual production.

Also, I've found that the average first year production is approximately 16 percent.

So I'd like to state that the IP is a misleading number. Also, I see some of the wells you're talking about with over 3-million IP wells -- IP data, some of these are also wells that had initial natural production tests taken on them in a manner I described earlier, with the pitot tube test. With that test I found that averaging all these wells involved, found that all these wells still stayed under the 336 Mcf per day criteria, which associates approximately to a .1 millidarcy at reservoir conditions. Therefor, if they are below the 336, using Darcy's Law they would also be below the .1 millidarcy for the area.

That is about the only way I can come up with -- with an answer to your question are the natural production tests that were taken;in each case they were below the .1 millidarcy in situ.

Q. I believe you indicated, though, that the pitot tube tests were not noted for their accuracy.

A. That's -- that's correct, they are not. But in most instances I believe that they would be reporting rates too high, is my feeling. I think the actual production, the stabilized production rate, would be much lower than they report.

Q There is, as Mr. Padilla pointed out, a dearth of evidence relative to Townships 30 and 31 North, Ranges 2 and 3 West, the only evidence being that no wells have been drilled.

On what could we base a finding that the permeability in the area is .1 of a millidarcy or less and productive capacity would be less than 366?

A. That would just have to be used from -- from the data we found already in the adjoining townships. It is a way away but there has also been no -- no active drilling in this area, which indicates that the area needs to be further developed, which the 107 price would -- would definitely encourage that.

In answer to your question, there is really no way to -- to tie that area in with the rest of -- with the rest of the -- the middle part of the area where the data is. The only point, without drilling wells in that area, it's just going to be tough.

MR. STAMETS: We're going to take about a fifteen minute recess while we have a little conference up here among the staff, at which time we will resume the hearing.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. McCord, after examining the information which has been submitted here today, it would appear to the Division staff that it will be necessary to continue this case for the presentation of economics data, which would demonstrate the wells in the area are not economic under the current 103 price.

And I would ask that this additional information be coordinated with Mr. Frank Chavez, who is our District Supervisor in Aztec, and also providing information to Mr. Padilla as to what is being done and the process that you intend to use to provide this data.

MR. CARR: We'll be glad to do that and after we meet with Mr. Chavez we will -- and agree on exactly what data is going to be required -- we'll notify all those who appeared in this case of what additional information has been requested.

MR. STAMETS: I'd also suggest that if there is any evidence which could be brought in that would help relative to 30 and 31 North, 2 and 3 West, that should be offered.

Is there anything -- any other questions of this witness? The witness may be excused.

I understood that there might someone here who would have trouble getting back and would like to make a statement.

MR. PAULSON: Yes, Mr. Examiner. Gary Paulson on behalf of Amoco Production Company.

We have come today in support of this application as a working interest owner in the area. It is our feeling that the added incentive price is required and necessary for future Basin Dakota development, and we would ask that the application be favorably considered by the Commission.

We do have evidence to present to the effect that a number of the wells that have been drilled in this area, in the Rosa Unit, were drilled upon demand by the USGS, and we had with respect to one year, 1980, evidence to present to the effect that the development plans submitted by the working interest owners for the Rosa Unit was to the effect that no wells were drilled and the USGS rejected that, and required -- or eventually a plan was submitted whereby three wells were drilled.

So at least some of the development activity in the area has been as a result of the USGS demand rather than a economic decision which was made by the working interest owners in the area.

And that will support the intent and we certainly have that evidence available in the event the Commission would like to consider it.

Thank you very much.

MR. STAMETS: Any other statements?

MR. PAID: Mr. Chairman, my name is Larry Pain. I'm an attorney with Phillips Petroleum Company.

Phillips Petroleum Company does support the application and urges that it be granted.

We are responsible for drilling of several of the wells that are listed in Exhibit Three that were drilled in 1980 and 1981, and you have requested additional economic information. We believe that any such information would show that some of the wells that were drilled were drilled with acceptable economics on the basis that they were within a small area that is somewhat more favorable than the remainder of the area covered by the application.

We feel that there are very few, if any, additional prospects of that character in the area covered by the application.

We are prepared to submit further evidence in that regard, if you would like for us to do so.

Phillips owns approximately 27,008 acres of oil and gas leases in the area covered by the application. Granting of the application would provide us with numerous additional drillable prospects over what we face now. What we face now is largely uneconomic prospects in the area.

We believe that the Commission should take a favorable attitude toward the granting of applications for tight formations where the criteria are reasonably satisfied. Common sense tells us that the price limits established under the Natural Gas Policy Act of 1978 are considerably lower than the BTU equivalent of oil prices and that the pricing assumptions that were used by Congress;to-wit, oil equivalency as of the time of enactment of the NGPA was an assumption that worldwide prices would not rise any faster than the rate of inflation, has been completely shattered by events which have occurred since the enactment of the NGPA. With world oil selling at well in excess of $30.00 per barrel, and an assumption of a 5.8 BTU equivalency factor, any gas that can be developed at any cost less than approximately $6.00 per Mcf can and should be developed in order to enhance our domestic supply situation and reduce our dependency on imports.

The Section 107 pricing authority under the NGPA is an appropriate method for stimulating additional domestic gas sources, which should be viewed favorably by this Commission and also by the FERC as it reviews your recommendations.

Thank you very much.

MR. STAMETS: Are there any other statements at this time?

Go off the record a second.

(Thereupon discussion was had off the record.)

Is there anything further in this case today?

This case, then, will be continued to the August 26th Examiner Hearing.

(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. 7317 heard by me on 7-29 1981.

Richard L. Stamets, Examiner
Oil Conservation Division

LIST OF EXHIBITS

EXHIBIT NUMBER	EXHIBIT NAME	PURPOSE OF EXHIBIT
1	Dakota Reservoir Map	Show location of Rosa Tight Gas Area with respect to Basin Dakota production.
2	Dakota Formation Well Completion and Production Map	Show production figures of completed and dry Dakota wells in and around the tight formation area.
3	Rosa Tight Gas Area Wells	List production figures of completed and dry Dakota wells in the tight formation area.
4	Type Log	Show log characteristics and depth of Dakota formation.
5	Cross Section A-A'	Show Dakota formation development in a west-east direction.
6	Cross Section B-B'	Show Dakota formation development in a north-south direction.
7	Core Analyisis Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	Show average laboratory core permeability.
8	Core Analysis El Paso Natural Gas Company San Juan 30-5 Unit No. 28-X	Show average laboratory core permeability.
9	Core Analysis El Paso Natural Gas Company San Juan 30-6 Unit No. 31	Show average laboratory core permeability.
10	Core Analysis Amoco Production Company Rosa Unit No. 1	Show average laboratory core permeability.
11	Core Analysis Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	Show average laboratory core permeability.
12	Core Analysis Blackwood & Nichols, LTD. Northeast Blanco Unit No. 1	Show average laboratory core permeability.
13	Technical Paper	Present relationship between laboratory and in situ permeability.
14	Determination of In Situ Permeability	Show method of determining in situ permeability from laboratory core analysis.
15	Summary of Permeability Data	Shows summary of permeability data, average laboratory permeability and in situ permeability.
16	Natural Production Tests	Lists natural production tests taken and average results.
17	Darcy's Law Calculation	Show unstimulated gas production rate using average in situ permeability.

EXHIBIT NO. 3

ROSA TIGHT GAS AREA WELLS

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Sunray DX Oil Co.	#1 Jicarilla Tribal	NW/NW 34 30-3	8213	09/64	D&A	---	---
El Paso Natural Gas Co.	Carson #2	NW/SW 7 30-4	8083	09/79	869/0	302/0	.055/0
El Paso Natural Gas Co.	39 San Juan 30-4 Unit	SE/NW 18 30-4	8425	02/81	2506/0	New Well	---
Coastline Petroleum	1 Schalk-76	SW/NW 25 30-4	8675	02/75	D&A	---	---
Southland Royalty Co.	#1 Carson	NW/SW 1 30-5	8030	10/69	2129/0	129/0	.518/0
Schalk Development Co.	Schalk #54	SE/NE 2 30-5	8018	01/73	2501/0	111/0	.297/0
Schalk Development Co.	Schalk #55	NE/NE 3 30-5	7940	03/73	3298/0	34/0	.126/0
Southland Royalty Co.	Cat Draw #1	SW/SW 4 30-5	7780	09/68	2074/0	SI	.186/0
Northwest Pipeline Corp.	39 San Juan 30-5 Unit	SW/NE 7 30-5	7686	07/75	1703/0	67/0	.123/0
Northwest Pipeline Corp.	37 San Juan 30-5 Unit	NE/SW 8 30-5	7688	01/74	3944/0	37/0	.503/0
Northwest Pipeline Corp.	70 San Juan 30-5 Unit	NE/NE 9 30-5	7752	12/80	1584/0	New Well	---
Northwest Pipeline Corp.	49 San Juan 30-5 Unit	SW/SW 9 30-5	7683	12/80	855/0	New Well	---
Northwest Pipeline Corp.	73 San Juan 30-5 Unit	NW/NE 10 30-5	7919	03/81	2635/0	New Well	---
Northwest Pipeline Corp.	72 San Juan 30-5 Unit	SW/SW 10 30-5	7790	04/81	2456/0	New Well	---
Schalk Development Co.	Schalk #57	NE/NW 12 30-5	8009	07/73	5107/0	148/0	.452/0
Northwest Pipeline Corp.	52 San Juan 30-5 Unit	SE/SW 15 30-5	7920	03/81	2679/0	New Well	---
Northwest Pipeline Corp.	53 San Juan 30-5 Unit	NE/SW 16 30-5	7685	12/80	1209/0	New Well	---
Northwest Pipeline Corp.	47 San Juan 30-5 Unit	NW/SW 17 30-5	7794	08/75	1610/0	129/0	.235/0

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	38 San Juan 30-5 Unit	SW/NE 18 30-5	7667	06/80	2035/0	New Well	---
Northwest Pipeline Corp.	6 San Juan 30-5 Unit	SW/SW 19 30-5	7607	03/56	P&A	---	---
Northwest Pipeline Corp.	48 San Juan 30-5 Unit	NW/NE 20 30-5	7790	01/80	3691/0	New Well	---
Northwest Pipeline Corp.	27 San Juan 30-5 Unit	SW/SW 20 30-5	7646	12/59	1309/0	24/0	.248/0
Northwest Pipeline Corp.	51 San Juan 30-5 Unit	NW/NE 21 30-5	7759	12/80	4792/0	New Well	---
Northwest Pipeline Corp.	71 San Juan 30-5 Unit	SW/SW 22 30-5	7807	12/80	2145/0	New Well	---
El Paso Natural Gas Co.	28-23-X San Juan 30-5 Unit	NE/NE 23 30-5	8075	09/59	D&A	---	---
Northwest Pipeline Corp.	38 San Juan 31-6 Unit	NE/NW 2 30-6	7832	04/81	2828/0	New Well	---
El Paso Natural Gas Co.	31 San Juan 30-6 Unit	SE/SW 33 30-6	7550	07/59	964/0	29/0	.255/0
Blackwood & Nichols	12 NE Blanco Unit	SW/NE 18 30-7	7590	06/60	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #42	SW/NE 19 31-4	not given	11/61	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #43	NW/SE 19 31-4	8158	05/62	2352/0	98/0	.064/0
Irving Pasternak	Rosa Unit #49	SW/SW 27 31-4	8430	11/63	P&A Dakota (MV Compl.)	---	---
Northwest Pipeline Corp.	Rosa Unit #63	SW/NE 30 31-4	8088	11/77	225/0	63/0	.004/0
Coastline Petroleum	1 Schalk-58	NE/SW 2 31-5	7856	08/73	D&A	---	---
Northwest Pipeline Corp.	Rosa Unit #53	NW/NE 8 31-5	7900	03/70	1043/0	126/0	.668/0
Northwest Pipeline Corp.	Rosa Unit #80	NE/SW 8 31-5	7845	03/81	2155/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #70	NW/NW 10 31-5	8162	01/66	1500/0	261/0	.248/0
Northwest Pipeline Corp.	Rosa Unit #48	SW/SE 11 31-5	8151	12/62	3207/0	326/0	.218/0
Northwest Pipeline Corp.	Rosa Unit #40	SW/NW 11 31-5	8358	07/61	3560/C	271/0	.216/0
Northwest Pipeline Corp.	Rosa Unit #61	SE/SW 13 31-5	8124	11/77	337/0	55/0	.074/0
Northwest Pipeline Corp.	Rosa Unit #65	NE/NE 17 31-5	7870	08/78	3095/0	163/0	.104/0
Northwest Pipeline Corp.	Rosa Unit #68	NW/SW 17 31-5	not given	08/80	5757/0	609/0	.093/0
Northwest Pipeline Corp.	Rosa Unit #62	NE/NW 25 31-5	8088	11/77	342/0	82/0	.106/0
Northwest Pipeline Corp.	Rosa Unit #64	NE/NE 29 31-5	7950	10/78	1843/0	175/0	.132/0
Northwest Pipeline Corp.	Rosa Unit #52	NW/NW 33 31-5	7980	02/70	2401/0	248/0	1.095/0
Northwest Pipeline Corp.	Rosa Unit #55	NE/SE 34 31-5	8056	10/74	264/0	167/0	.386/0
Northwest Pipeline Corp.	Rosa Unit #56	SW/NW 35 31-5	8200	11/75	675/0	96/0	.232/26
Northwest Pipeline Corp.	Rosa Unit #54	NE/SW 36 31-5	8284	09/74	304/0	SI	.029/0
Amoco Production Co.	Rosa Unit 35-X	NE/SW 5 31-6	7822	10/59	D&A Dak. MV Comp.	---	---
Amoco Production Co.	Rosa Unit #36	SE/NE 11 31-6	7955	12/59	P&A MV Comp.	---	---
Amoco Production Co.	Rosa Unit #1	SW/SE 11 31-6	7865	09/52	560/0 (P&A)		---
Northwest Pipeline Corp.	Rosa Unit #66	NW/SW 13 31-6	7957	08/78	4427/0	245/0	.928/0
Amoco Production Co.	Rosa Unit #69	NW/NW 16 31-6	7918	09/80	P&A	---	---
Northwest Pipeline Corp.	79 San Juan 31-6 Unit	NE/SW 22 31-6	7757	03/81	1858/0	New Well	---

COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Rosa Unit #51	NE/NW 23 31-6	7823	01/70	1385/0	170/0	.736/0
Northwest Pipeline Corp.	36 San Juan 31-6 Unit	NE/NE 27 31-6	7806	03/81	2557/0	New Well	---
Northwest Pipeline Corp.	24 San Juan 31-6 Unit	NE/SW 27 31-6	7939	12/73	1341/0	SI	.269/0
Northwest Pipeline Corp.	16 San Juan 31-6 Unit	SE/SW 33 31-6	7895	07/59	1783/0	SI	.074/0
Northwest Pipeline Corp.	33 San Juan 31-6 Unit	SW/NE 34 31-6	8712	06/80	4119/0	New Well	---
Northwest Pipeline Corp.	35 San Juan 31-6 Unit	NE/NE 35 31-6	7908	07/80	2643/0	New Well	---
Northwest Pipeline Corp.	31 San Juan 31-6 Unit	SE/SE 35 31-6	7796	06/80	3770/0	New Well	---
Northwest Pipeline Corp.	37 San Juan 31-6 Unit	SW/SE 36 31-6	7952	04/81	2370/0	New Well	---
Blackwood & Nichols	58 NE Blanco Unit	NE/NE 13 31-7	7975	11/59	2461/0	217/0	1.387/0
Blackwood & Nichols	57 NE Blanco Unit	NE/NE 21 31-7	7780	09/59	1235/0	37/0	.444/0
Blackwood & Nichols	55 NE Blanco Unit	NW/NE 22 31-7	7856	10/58	275/0	27/0	.182/0
Blackwood & Nichols	1 NE Blanco Unit	SE/NE 27 31-7	7792	10/52	536/0	217/0	2.398/0
Amoco Production Co.	McKay #1	NW/NE 28 31-7	7765	03/71	D&A	---	---
Blackwood & Nichols	56 NE Blanco Unit	NE/NE 34 31-7	7660	11/58	2839/0	30/0	.417/0

EXHIBIT NO. 7

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 30-5 Unit No. 27
Basin Dakota Field
SW/SW, Sec. 20, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7650-7651	1	0.01
7651-7652	1	0.01
7652-7653	1	0.01
7653-7654	1	0.02
7654-7655	1	0.01
7655-7656	1	0.02
7658-7659	1	0.02
7661-7662	1	0.03
7662-7663	1	0.02
7667-7668	1	0.02
7669-7670	1	0.01
7670-7671	1	0.02
7688-7689	1	0.01
7689-7690	1	0.01
7690-7691	1	0.60
7691-7692	1	0.01
7692-7693	1	0.01
7694-7695	1	0.02
7696-7697	1	0.25
7697-7698	1	0.01
7707-7708	1	0.01
7708-7709	1	0.02
7709-7710	1	0.03
7719-7720	1	0.01
7720-7721	1	1.51
7721-7722	1	0.07
7722-7723	1	0.25
7723-7724	1	0.10
7724-7725	1	0.01
7727-7728	1	0.02
7728-7729	1	0.04
7729-7730	1	0.02
7730-7731	1	0.01
7731-7732	1	0.04
7732-7733	1	0.02
7733-7734	1	0.66
7769-7770	1	0.04
7770-7771	1	0.03
7771-7772	1	0.03
7773-7774	1	0.01
7774-7775	1	0.01
7775-7776	1	0.02
7776-7777	1	1.44
7777-7778	1	0.11
7778-7779	1	0.10
7779-7780	1	0.21
7780-7781	1	0.13

San Juan 30-5 Unit No. 27, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.01
7783-7784	1	0.03
7784-7785	1	0.03
7785-7786	1	0.09
7786-7787	1	0.02
7787-7788	1	1.01
7788-7789	1	0.05
7789-7790	1	0.06
7790-7791	1	0.05
7791-7792	1	0.31
7792-7793	1	0.03
7793-7794	1	0.02
7794-7795	1	0.01
7795-7796	1	0.05
7796-7797	1	0.18
7797-7798	1	0.61
7798-7799	1	0.34
TOTAL	65	9.07

Avg. K = $\frac{9.07}{65}$ = 0.140 md.

CORE ANALYSIS REPORT

ompany El Paso Natural Gas Company
Vell No. San Juan 30-5 #27-20
ield Wildcat
ounty Rio Arriba
ate New Mexico

Date September 23, 1959 Lab. No.
Location Sec. 20-30N-5W
Formation Dakota
Depths 7649' - 7799'
Drilling Fluid Water Base Mud

LEGEND
C—Crack, F—Fracture, H—Horizontal, O—Open, NF—No Fracture, I—Insufficient Sample, S—Slight, St—Stain, V—Vertical, Vu—Vugs

* Permeability probably caused by existing shale interlaminations

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY PERCENT	PERMEABILITY MILLIDARCIES HORIZONTAL	PERMEABILITY MILLIDARCIES VERTICAL	SATURATIONS % PORE SPACE RESIDUAL OIL	SATURATIONS % PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	SOLUBILITY 15 % ACID
		Core No. 1	7649 - 7710							
1	VF	7650-51	7.7	0.01		Trace	27.8			
2	NF	7651-52	8.5	0.01		Trace	16.7			
3	VF	7652-53	6.7	0.01		Trace	12.2			
4	VF	7653-54	7.7	0.02		Trace	12.4			
5	VF	7654-55	[illegible].2	0.01		0	21.2			
6	VF	7655-56	8.6	0.02		0	15.8			
7	VF	7658-59	8.8	0.02		Trace	12.4			
8	VHF	7661-62	10.2	0.03		0	15.2			
9	VF	7662-63	9.6	0.02		0	19.2			
10	VHF	7667-68	10.0	0.02		Trace	20.5			
11	VHF	7669-70	6.5	0.01		Trace	15.4			
12	VHF	7670-71	7.9	0.02		1.4	20.6			
13	HF	7688-89	4.9	0.01		Trace	26.1			
14	HF	7689-90	5.0	0.01		Trace	24.2			
15	HF	7690-91	5.9	0.60*		Trace	35.9			
16	HF	7691-92	3.7	0.01		Trace	94.9			
17	VHF	7692-93	7.8	0.01		Trace	54.7			
18	NF	7694-95	9.3	0.02		Trace	14.2			
19	HF	7696-97	11.4	0.25*		0	27.7			
20	NF	7697-98	6.3	0.01		0	18.6			
21	VHF	7701-02	2.6	0.01		0	62.3			
22	VHF	7707-08	2.0	0.01		0	44.5			
23	VHF	7708-09	6.1	0.02		0	16.0			
24	VHF	7709-10	5.9	0.03		Trace	33.9			

El Paso Natural Gas Company
San Juan 30—5 #27-20

Wildcat
Rio Arriba County, New Mexico

LEGEND: C—Crack, F—Fracture, H—Horizontal, O—Open, NF—No Fracture, NS—No Core Sample, S—Slight, St—Stain, V—Vertical, Vu—Vugs

* Permeability probably caused by existing shale interlaminations

Sample No.	Legend	Depth, Feet	Effective Porosity % Porespace	Permeability Millidarcies Horizontal	Permeability Millidarcies Vertical	Saturations % Pore Space Residual Oil	Saturations % Pore Space Total Water	Connate Water	Solubility Mud Acid	Solubility 15% Acid
		Core No. 2 7710 - 7719 Recovered 9'								
		No samples analyzed								
		Core No. 3 7719 - 7727 Recovered 6½'								
25	VHF	7719-20	3.8	0.01		0	30.3			
26	HF	7720-21	2.8	1.51*		0	60.7			
27	HF	7721-22	3.4	0.07		0	33.8			
28	HF	7722-23	2.4	0.25*		0	60.8			
29	HF	7723-24	4.5	0.10*		0	51.6			
30	VHF	7724-25	2.6	0.01		0	38.5			
		Core No. 4 7727 - 7738 Recovered 10'								
31	VHF	7727-28	3.0	0.02		0	16.0			
32	VHF	7728-29	3.4	0.04		0	11.8			
33	VHF	7729-30	5.4	0.02		0	11.3			
34	VHF	7730-31	1.8	0.01		0	12.2			
35	HF	7731-32	3.9	0.04		0	13.9			
36	VF	7732-33	2.5	0.02		0	12.0			
37	HF	7733-34	3.9	0.66*		0	11.0			
		Core No. 5 7738 - 7799 Recovered 61'								
38	NF	7768-69	10.1	0.04		0	39.2			
39	NF	7769-70	10.8	0.04		0	45.4	41.5		
40	NF	7770-71	10.5	0.03		0	47.1			
41	NF	7771-72	7.7	0.03		0	38.4			
	-	7772-73	No sample taken							
42	NF	7773-74	5.9	0.01		Trace	49.2			
43	NF	7774-75	5.9	0.01		Trace	48.1			
44	VF	7775-76	2.5	0.02		Trace	55.2			
45	VF	7776-77	5.7	1.44*		Trace	49.6			
46	NF	7777-78	6.9	0.11		Trace	53.3	44.1		
47	NF	7778-79	7.4	0.10		0	33.3			
48	NF	7779-80	7.6	0.21		0	37.9	42.0		
49	NF	7780-81	6.2	0.13		0	40.3			
50	NF	7781-82	4.6	0.10		Trace	34.1			
51	VF	7782-83	3.8	0.01		Trace	86.8			
52	HF	7783-84	4.1	0.03		Trace	73.7			
53	NF	7784-85	4.2	0.03		Trace	66.3			
54	NF	7785-86	4.6	0.09		0	41.3			
55	NF	7786-87	5.4	0.02		0	53.0	44.7		
56	NF	7787-88	7.0	1.01*		0	42.0			
57	NF	7788-89	6.6	0.05		0	45.9	49.5		
58	NF	7789-90	6.9	0.06		0	49.6			
59	NF	7790-91	6.9	0.05		0	31.2			
60	NF	7791-92	6.4	0.31		0	26.1			
61	NF	7792-93	3.2	0.03		0	26.3			

El Paso Natural Gas Company
San Juan 30-5 #27-20

Wildcat
Rio Arriba County, New Mexico

LEGEND

C—Crack
F—Fracture
H—Horizontal
O—Open

NF—No Fracture
IS—Insufficient Sample

S—Slight
St—Stain
V—Vertical
Vu—Vugs

SAMPLE NO.	LEGEND	DEPTH, FEET	EFFECTIVE POROSITY % PORESPACE	PERMEABILITY MILLIDARCIES HORIZONTAL	PERMEABILITY MILLIDARCIES VERTICAL	SATURATIONS % PORE SPACE RESIDUAL OIL	SATURATIONS % PORE SPACE TOTAL WATER	CONNATE WATER	SOLUBILITY MUD ACID	SOLUBILITY 15 % ACID
		Core No. 5 continued								
62	VF	7793-94	5.8	0.02		0	39.1			
63	VF	7794-95	4.0	0.01		0	52.3			
64	NF	7795-96	8.3	0.05		0	49.9			
65	NF	7796-97	9.5	0.18		Trace	51.7			
66	NF	7797-98	9.4	0.61		Trace	52.1			
67	NF	7798-99	9.4	0.34		Trace	53.2	46.2		

EXHIBIT NO. 8

Company: El Paso Natural Gas Company
Well: San Juan 30-5 Unit No. 28-X
Basin Dakota Field
NE/NE, Sec. 23, T30N, R5W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8075-8076	1	0.02
8076-8077	1	0.01
8077-8078	1	0.01
8078-8079	1	0.01
8079-8080	1	0.01
8080-8081	1	0.01
8081-8082	1	0.01
8082-8083	1	0.01
8083-8084	1	0.01
8084-8085	1	0.01
8085-8086	1	0.01
8090-8091	1	0.01
8091-8092	1	0.01
8092-8093	1	0.01
8093-8094	1	0.01
8094-8095	1	0.01
8095-8096	1	0.01
8096-8096.8	.8	0.01
8116-8117	1	0.03
8117-8118	1	0.01
8118-8119	1	0.01
8119-8120	1	0.01
8120-8121	1	0.02
8121-8122	1	0.01
8122-8123	1	0.01
8123-8124	1	0.01
8124-8125	1	0.01
8125-8126	1	0.01
8126-8127	1	0.01
8127-8128	1	0.01
8128-8129	1	0.01
8129-8130	1	0.02
8130-8130.9	.9	0.01
8133-8134	1	0.01
8134-8135	1	0.01
8138-8139	1	0.01
8139-8140	1	0.01
8140-8141	1	0.01
8141-8142	1	0.01
8142-8143	1	0.01
8143-8144	1	0.01
8144-8145	1	0.01
8145-8146	1	0.01
8146-8147	1	0.01
8147-8148	1	0.65
8148-8149	1	0.01
8155-8156	1	0.01
8156-8157	1	0.01
8157-8158	1	0.01
8158-8159	1	0.01
8159-8160	1	0.01
8160-8161	1	0.05
8161-8162	1	0.02
8162-8163	1	7.2

San Juan 30-5 Unit No. 28-X, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8163-8164	1	0.01
8164-8165	1	0.02
8165-8166	1	0.01
8166-8167	1	0.01
8167-8168	1	0.01
8190-8191	1	2.10
8191-8192	1	0.24
8192-8193	1	0.01
8193-8194	1	0.07
8200-8201	1	0.01
8201-8202	1	0.01
8202-8203	1	0.01
8203-8204	1	0.01
8204-8205	1	0.01
8205-8206	1	0.01
8206-8207	1	0.01
8207-8208	1	0.01
8208-8209	1	0.01
8209-8210	1	0.01
8210-8211	1	0.01
8222-8223	1	0.19
8223-8224	1	0.01
8224-8225	1	0.01
8225-8226	1	0.01
8226-8227	1	0.01
8229-8230	1	0.01
8230-8231	1	0.02
8238-8239	1	0.01
8239-8240	1	0.01
8240-8241	1	0.01
8241-8242	1	0.01
8242-8243	1	0.28
8246-8247	1	0.01
8247-8248	1	0.01
TOTAL	87.7	11.66

Avg. $\frac{11.66}{87.7} = \underline{0.133 \text{ md}}$

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

COMPANY	EL PASO NATURAL GAS COMPANY	DATE ON	8/30/59	FILE NO.	RP-3-1065
WELL	SAN JUAN 30-5 No. 28-23 - X	DATE OFF	9/8/59	ENGRS.	ENGLISH
FIELD	BLANCO MESA VERDE DAKOTA WILDCAT	FORMATION	DAKOTA	ELEV.	6753' DF
COUNTY	RIO ARRIBA STATE N.MEXICO	DRLG. FLD.	OIL EMULSION	CORES	DIAMOND
LOCATION	SEC23 T30N R5W	REMARKS	SAMPLED BY CLIENT		

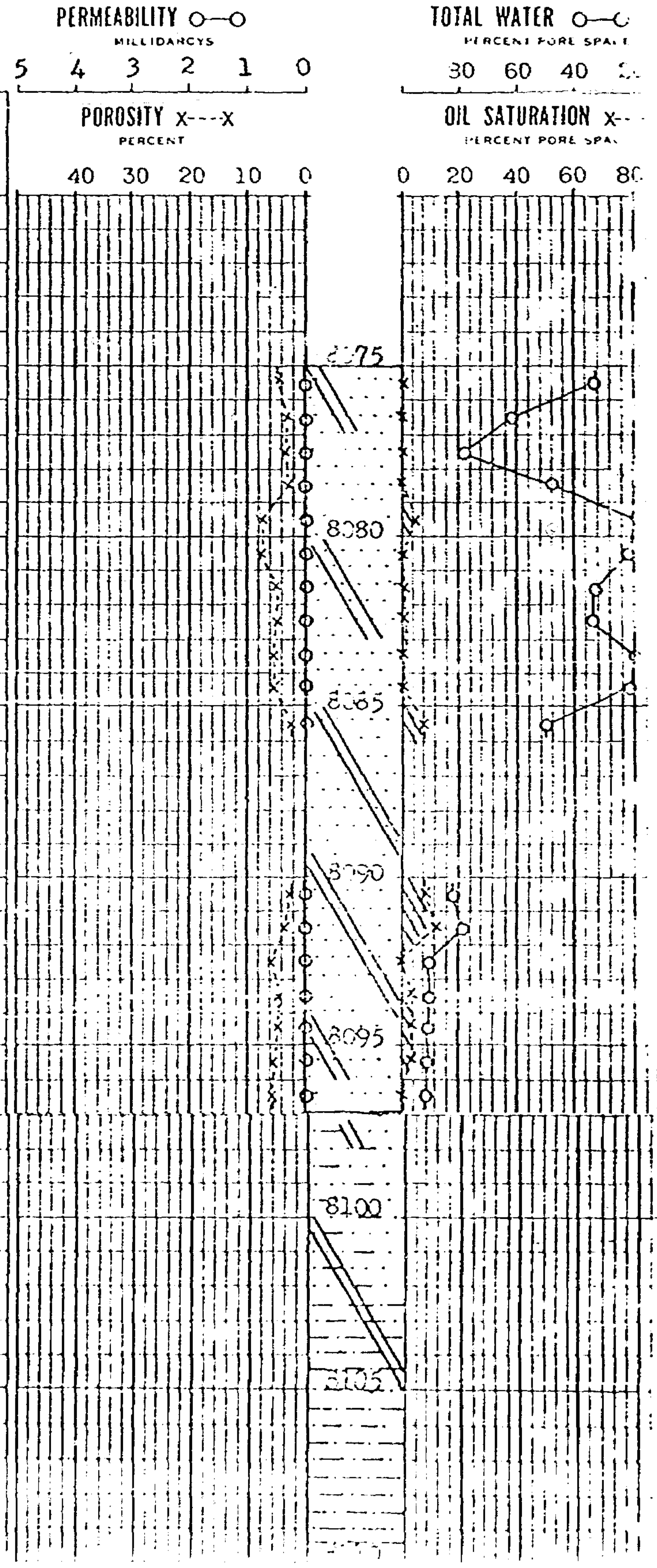
SAND · LIMESTONE · CONGLOMERATE · CHERT · SHALE · DOLOMITE · VERTICAL FRACTURE

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.

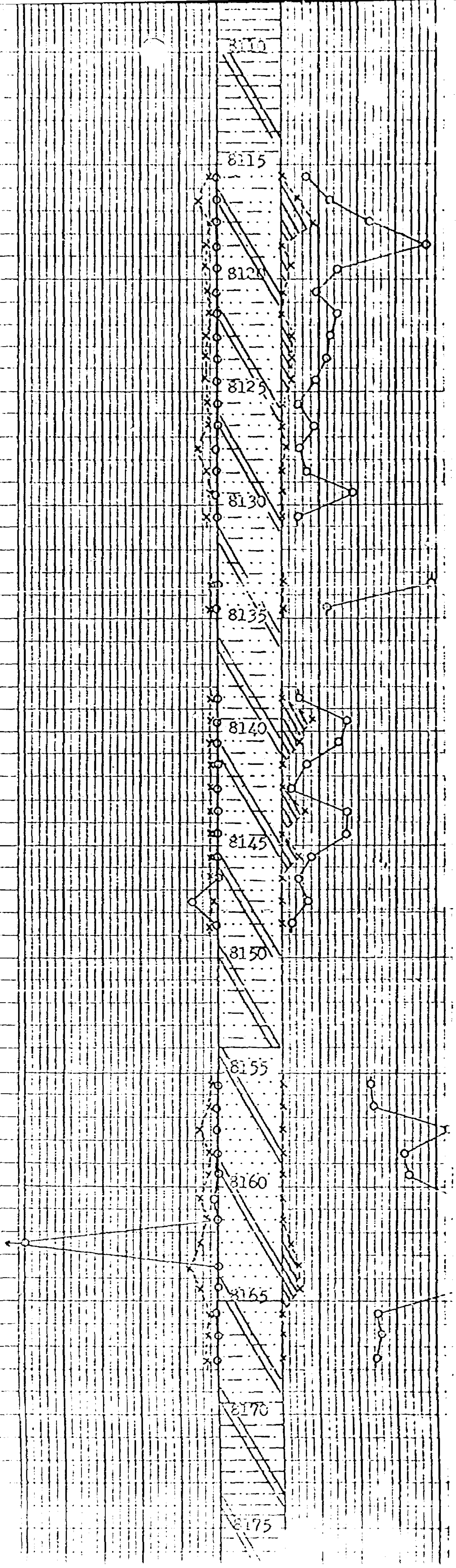
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER	BOYLE'S LAW POROSITY	PROD
1	8075-76	0.02	4.6	0.0	32.6		
2	76-77	<0.01	3.4	0.0	61.8		
3	77-78	<0.01	2.8	0.0	78.6		
4	78-79	<0.01	2.5	0.0	48.0		
5	79-80	<0.01	7.6	6.6	19.8		
6	80-81	<0.01	7.0	0.0	21.4		
7	81-82	<0.01	4.5	0.0	33.4		
8	82-83	<0.01	4.3	0.0	34.9		
9	83-84	<0.01	5.5	0.0	20.0		
10	84-85	<0.01	5.2	0.0	21.2		
11	85-86	<0.01	2.4	8.3	50.0		
12	8090-91	<0.01	2.2	9.1	81.8		
13	91-92	<0.01	3.7	13.5	78.4		
14	92-93	<0.01	5.7	0.0	87.7		
15	93-94	<0.01	4.2	4.8	90.5		
16	94-95	<0.01	4.3	4.7	88.4		
17	95-96	<0.01	4.8	4.2	87.5		
18	96-96.8	<0.01	5.7	0.0	91.3		

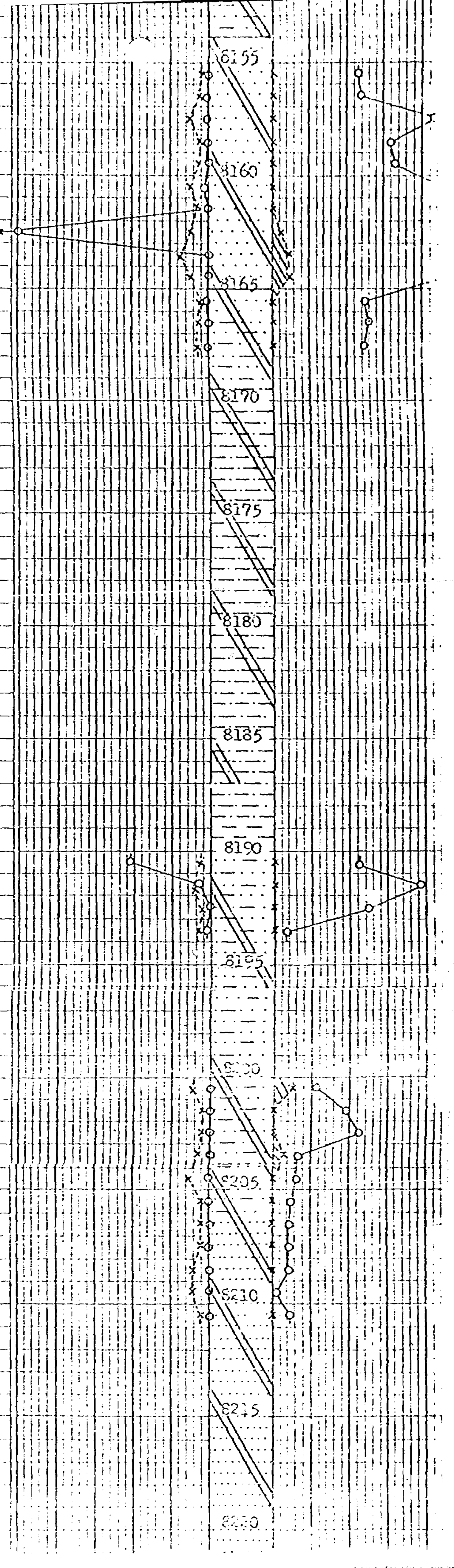
COMPLETION COREGRAPH



19	8115.5-16	0.01	2.2	0.0	86.4	1.9
20	16-17	0.03	5.0	10.0	74.0	2.9
21	17-18	<0.01	1.1	18.2	54.6	2.9
22	18-19	<0.01	2.5	0.0	24.0	3.6
23	19-20	<0.01	3.4	5.9	70.6	4.8
24	20-21	0.02	2.5	0.0	80.1	3.6
25	21-22	<0.01	2.1	0.0	71.4	3.1
26	22-23	<0.01	3.2	6.2	74.9	3.4
27	23-24	<0.01	3.4	5.9	76.5	4.3
28	24-25	<0.01	3.8	5.3	81.6	4.1
29	25-26	<0.01	3.0	0.0	90.0	3.3
30	26-27	<0.01	3.4	0.0	82.4	3.5
31	27-28	<0.01	5.8	3.4	89.7	2.4
32	28-29	<0.01	2.9	0.0	86.2	2.6
33	29-30	0.02	1.9	0.0	63.1	1.1
34	30-30.9	<0.01	3.2	0.0	90.7	4.3
35	8133-34	<0.01	1.9	0.0	21.0	2.8
36	34-35	<0.01	2.1	0.0	76.3	4.0
37	8138-39	<0.01	1.8	0.0	89.0	1.7
38	39-40	<0.01	1.2	16.7	66.6	1.0
39	40-41	<0.01	1.7	11.8	70.6	1.9
0	41-42	<0.01	1.4	0.0	85.6	2.0
1	42-43	0.01	1.8	0.0	94.4	2.2
2	43-44	<0.01	1.5	13.3	66.8	2.2
3	44-45	<0.01	0.9	0.0	66.7	1.9
4	45-46	<0.01	1.9	10.5	84.3	2.2
5	46-47	<0.01	1.3	0.0	92.4	3.3
6	47-48	0.65	1.4	0.0	85.7	5.1
7	48-49	<0.01	2.2	0.0	95.0	1.8
8	8155-56	<0.01	1.1	0.0	54.5	
9	56-57	<0.01	2.3	0.0	52.2	
0	57-58	0.01	5.4	0.0	14.8	
1	58-59	<0.01	2.2	0.0	36.3	
2	59-60	<0.01	1.8	0.0	33.3	
3	60-61	0.05	5.7	0.0	10.5	
4	61-62	0.02	3.6	0.0	11.1	
5	62-63	7.2	4.8	4.2	8.3	
6	63-64	0.01	7.2	9.7	8.5	
7	64-65	0.02	5.1	9.8	7.8	
8	65-66	<0.01	1.2	0.0	50.0	
9	66-67	<0.01	2.9	0.0	48.2	
0	67-68	<0.01	2.4	0.0	50.0	



48	8155-56	<0.01	1.1	0.0	54.5
49	56-57	<0.01	2.3	0.0	52.2
50	57-58	0.01	5.4	0.0	14.8
51	58-59	<0.01	2.2	0.0	36.3
52	59-60	<0.01	1.8	0.0	33.3
53	60-61	0.05	5.7	0.0	10.5
54	61-62	0.02	3.6	0.0	11.1
55	62-63	7.2	4.8	4.2	8.3
56	63-64	0.01	7.2	9.7	8.5
57	64-65	0.02	5.1	9.8	7.8
58	65-66	<0.01	1.2	0.0	50.0
59	66-67	<0.01	2.9	0.0	48.2
60	67-68	<0.01	2.4	0.0	50.0
1	8190-91	2.1	2.7	0.0	55.6
2	91-92	0.24	2.8	0.0	21.4
3	92-93	0.01	2.0	0.0	50.0
4	93-94	0.07	2.6	0.0	92.3
	8200-01	<0.01	4.3	11.6	76.8
	01-02	<0.01	1.3	0.0	61.5
	02-03	0.01	1.7	0.0	35.3
	03-04	<0.01	2.9	6.9	86.3
	04-05	<0.01	5.5	0.0	85.5
	05-06	<0.01	1.9	0.0	89.4
	06-07	<0.01	1.6	0.0	93.8
	07-08	<0.01	1.4	0.0	93.0
	08-09	<0.01	4.2	0.0	95.0
	09-10	<0.01	4.1	0.0	97.6
	10-11	<0.01	1.4	0.0	93.0



			[illegible]	[illegible]	76.8
6	01-02	<0.01	1.3	0.0	61.5
7	02-03	0.01	1.7	0.0	[illegible]
8	03-04	<0.01	2.9	6.9	86.3
9	04-05	<0.01	5.5	0.0	85.5
70	05-06	<0.01	1.9	0.0	89.4
1	06-07	<0.01	1.6	0.0	93.8
2	07-08	<0.01	1.4	0.0	93.0
3	08-09	<0.01	4.2	0.0	95.0
4	09-10	<0.01	4.1	0.0	97.6
5	10-11	<0.01	1.4	0.0	93.0
6	8222-23	0.19	3.9	0.0	97.5
7	23-24	<0.01	1.0	20.0	80.0
8	24-25	<0.01	0.6	0.0	66.6
9	25-26	0.01	1.3	0.0	15.4
0	26-27	<0.01	0.8	0.0	25.0
1	8229-30	<0.01	1.2	0.0	83.4
2	30-31	0.02	1.4	0.0	14.3
3	8238-39	0.01	0.9	0.0	44.5
[illegible]	39-40	<0.01	1.3	0.0	46.1
[illegible]	40-41	<0.01	0.9	0.0	66.6
[illegible]	41-42	0.01	1.0	0.0	40.0
	42-43	0.28	4.5	0.0	93.4
	8246-47	<0.01	3.3	6.1	88.0
	8247-48	<0.01	4.6	4.4	91.3

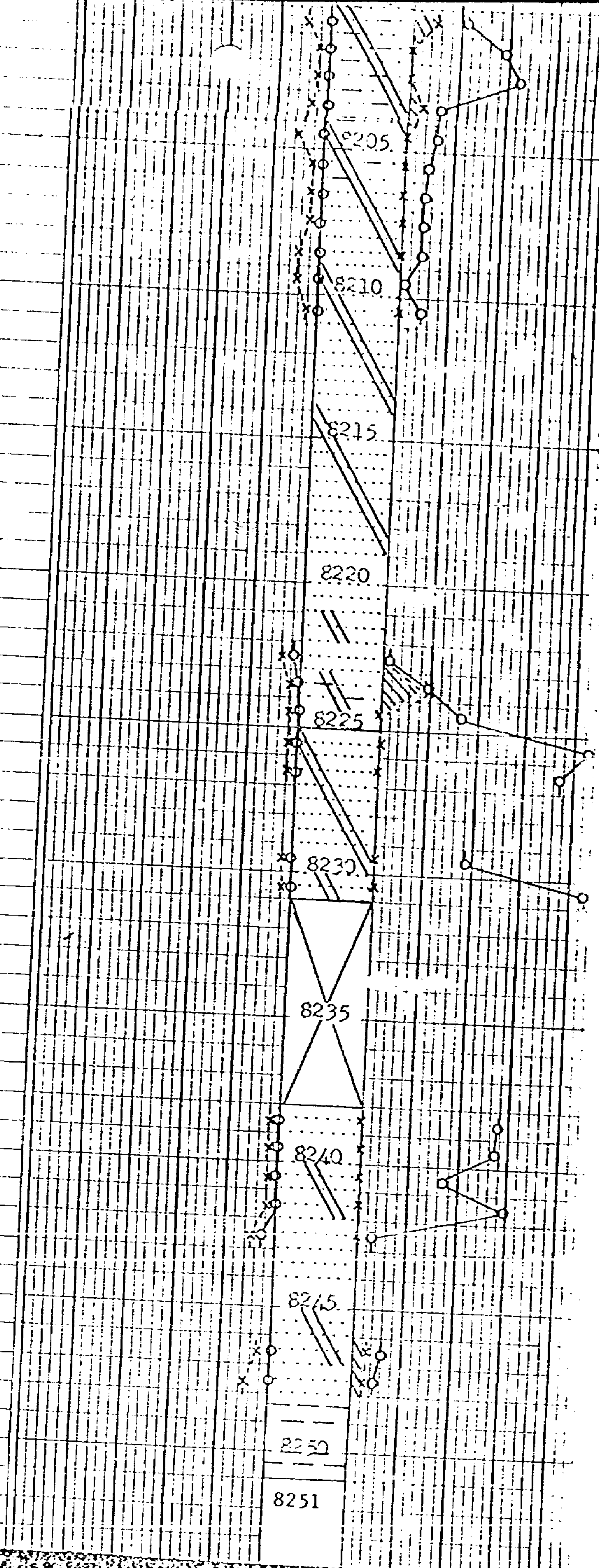


EXHIBIT NO. 9

Company: El Paso Natural Gas Company
Well: San Juan 30-6 Unit No. 31
Basin Dakota Field
SE/SW, Sec. 33, T30N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7635-7636	1	0.01
7636-7637	1	0.01
7637-7638	1	0.05
7638-7639	1	0.07
7639-7640	1	0.01
7640-7641	1	0.10
7641-7642	1	< 0.01
7642-7643	1	< 0.01
7643-7644	1	0.01
7644-7645	1	< 0.01
7645-7646	1	0.01
7646-7647	1	< 0.01
7647-7648	1	< 0.01
7716-7717	1	0.13
7717-7718	1	0.04
7718-7719	1	0.01
7719-7720	1	0.90
7720-7721	1	< 0.01
7721-7722	1	< 0.01
7722-7723	1	< 0.01
7723-7724	1	< 0.01
7724-7725	1	< 0.01
7725-7726	1	< 0.01
7746-7747	1	0.04
7751-7752	1	0.01
7752-7753	1	0.06
7753-7754	1	1.90
7754-7755	1	0.27
7755-7756	1	0.01
7756-7757	1	0.03
7757-7758	1	0.17
7758-7759	1	0.05
7759-7760	1	0.90
7760-7761	1	1.00
TOTAL	34	5.90

$$\text{Avg. K} = \frac{5.90}{34} = 0.174 \text{ md}$$

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

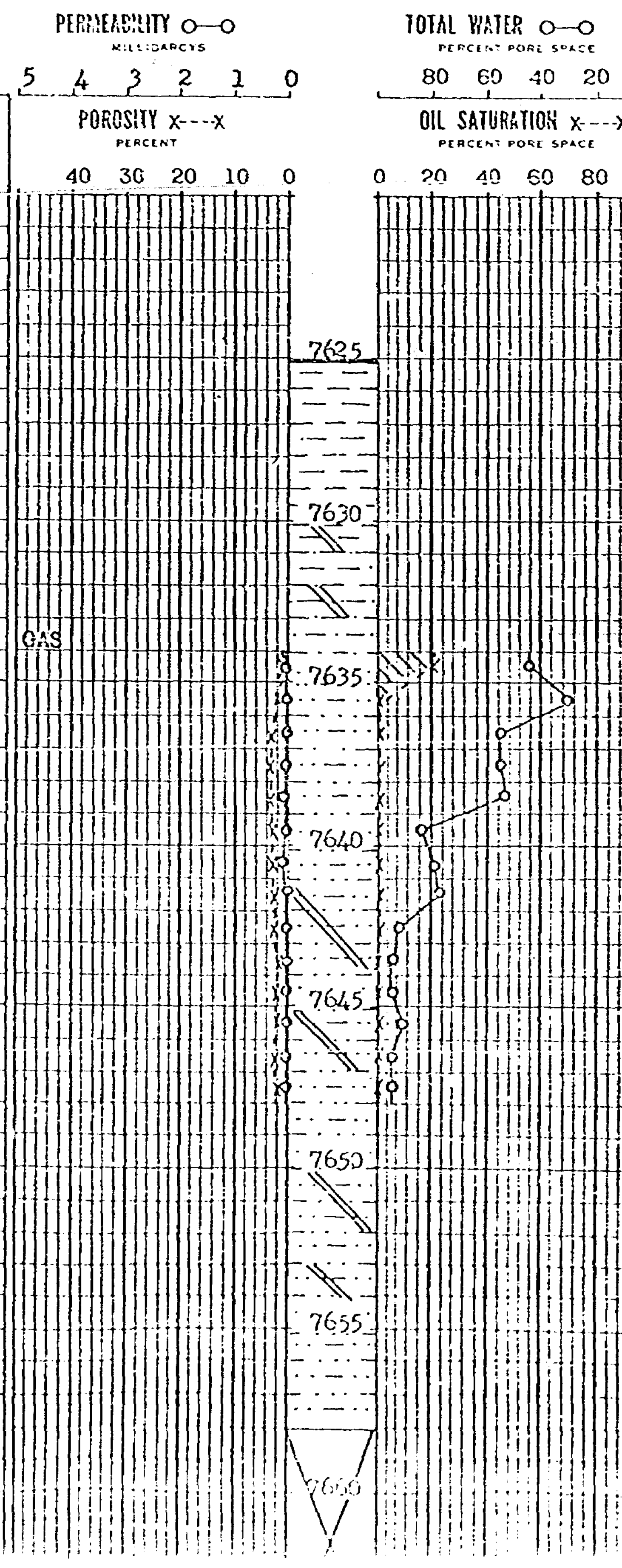
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 5/31/59 FILE NO. RP-3-997
WELL SAN JUAN 30-6 No. 31 DATE OFF 6/8/59 ENGRS. ENGLISH
FIELD WILDCAT FORMATION DAKOTA ELEV. 6364' DF
COUNTY RIO ARRIBA STATE N. MEXICO DRLG. FLD. AS NOTED CORES DIAMOND
LOCATION SEC 33 - T30N - R6W REMARKS SAMPLED BY CLIENT

SAND LIMESTONE CONGLOMERATE CHERT
SHALE DOLOMITE FRACTURES

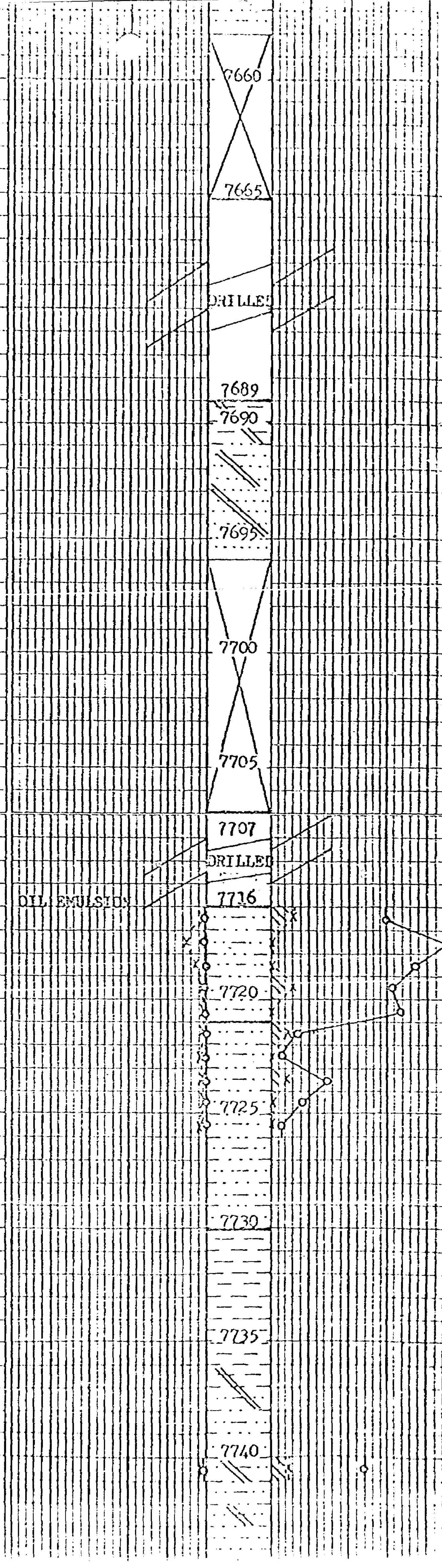
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	TOTAL WATER		PROD
1	7634-35	<0.01	0.9	22.3	44.5		
2	35-36	0.01	1.9	0.0	31.6		
3	36-37	0.01	2.5	0.0	56.1		
4	37-38	0.05	3.2	0.0	56.3		
5	38-39	0.07	3.3	0.0	54.6		
6	39-40	0.01	2.5	0.0	84.1		
7	40-41	0.10	2.9	0.0	79.3		
8	41-42	<0.01	2.6	0.0	77.0		
9	42-43	<0.01	2.1	0.0	90.6		
10	43-44	0.01	1.8	0.0	94.4		
11	44-45	<0.01	2.0	0.0	95.1		
12	45-46	0.01	1.9	0.0	89.5		
13	46-47	<0.01	2.2	0.0	95.4		
14	47-48	<0.01	1.8	0.0	94.6		

COMPLETION COREGRAPH



15	7716-17	0.13	1.5	13.3	40.0
16	17-18	0.04	5.3	0.0	11.3
17	18-19	0.01	2.3	0.0	26.5
18	19-20	0.9	1.6	12.5	37.5
9	20-21	<0.01	0.6	0.0	33.3
0	21-22	<0.01	2.0	10.0	85.0
1	22-23	<0.01	1.7	0.0	94.0
2	23-24	<0.01	2.1	9.1	71.5
3	24-25	<0.01	1.2	0.0	83.4
4	25-26	<0.01	2.2	0.0	95.5
5	7740-41	0.04	1.9	10.5	52.7



25	7740-41	0.04	1.9	10.5	52.7
26	7746-47	0.04	1.6	31.3	50.0
27	7751-52	0.01	2.4	8.3	66.7
28	52-53	0.06	7.9	0.0	30.4
29	53-54	1.9	10.2	5.0	16.8
30	54-55	0.27	7.8	6.4	15.4
31	55-56	0.01	1.6	0.0	50.0
32	56-57	0.03	4.2	4.8	23.9
33	57-58	0.17	4.8	0.0	4.2
34	58-59	0.05	0.7	0.0	28.4
35	59-60	0.9	0.6	0.0	33.3
36	60-61	1.0	1.2	0.0	16.7

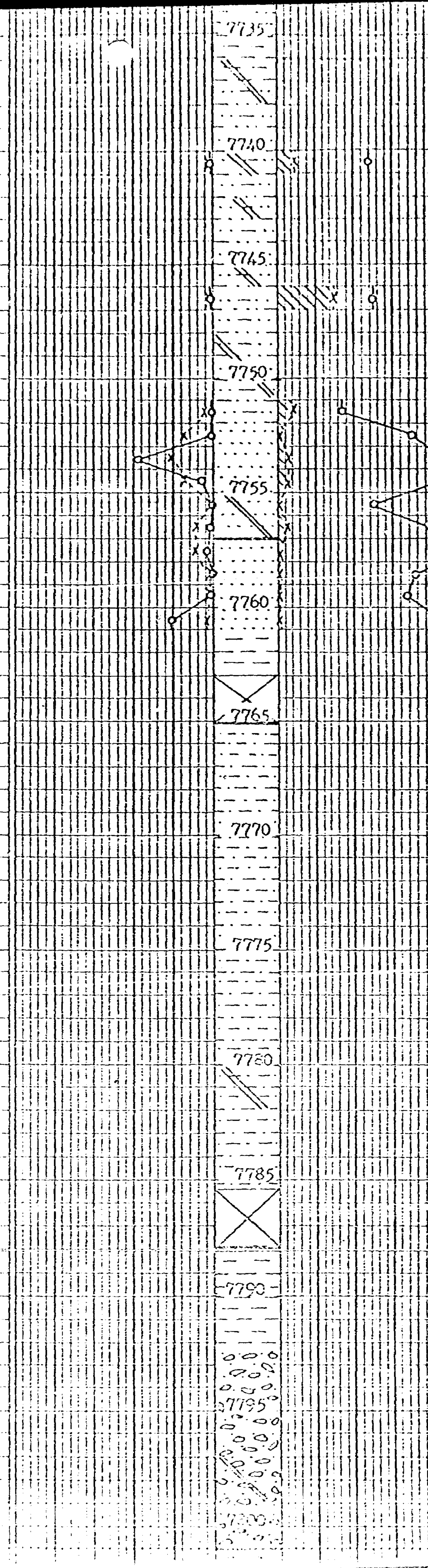


EXHIBIT NO. 10

Company: Amoco Production Company
Well: #1 Rosa Unit
Basin Dakota Field
SW/SE, Sec. 11, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7878-7879	1	0.05
7912-7914	2	0.05
7914-7916	2	0.34
7916-7923	7	0.05
7923-7928	5	0.18
7928-7930	2	0.59
7930-7931	1	0.05
7932-7936	4	0.05
TOTAL	24	

Weighted Total = 3.51 md

$$\text{Avg. } K = \frac{3.51}{24} = \underline{0.146 \text{ md}}$$

DENVER REGION

AMOCO PRODUCTION COMPANY
CORE ANALYSIS LISTING

API WELL NUMBER - 30 039 07972 00
REGION 5 PAGE 01

API WELL NUMBER	GROUP NO.	CURRENT DATE	DATE ANALYZED
30 039 07972 00	03	81-05-05	49-05-06

------------WELL OPERATOR------------ LOC WELL NO ------LEASE NAME------ LATITUDE LONGITUDE ELEVATION

ORIG: STANOLIND OIL & GAS 1 ROSA UNIT 36.9082800 107.4291900 6548.0 DF

CURR: STANOLIND OIL & GAS 1 ROSA UNIT

SEC TWP RGE QTR QTR QTR	COUNTY STATE	FIELD CODE	ORIG COMP DATE	TOTAL DEPTH
0011 031N 006W	RIO ARRIBA NM	00008500	49-09-10	8087.00

ANALYZING LABORATORY: STANOLIND OIL AND GAS COMPANY CITY: INPUT FORMAT 119

* CORE TYPE-----------DIAMOND CORE SIZE---------- INCHES *
* PRIMARY SPL TYPE---CONVENTIONAL - PLUG DRILLING FLUID----CHEMICAL MUD *
* SECONDARY SPL TYPE- EXTRACTION METHOD-RETORT *
* ANALYSIS TYPE------SUMMATION OF FLUIDS MULTIPLE DATA------NO *

----- FORMATION -----		----- FORMATION -----		----- FORMATION -----		----- FORMATION -----	
STRAT MNEMONIC	FIRST CORE DEPTH	STRAT MNEMONIC	FIRST CORE DEPTH	STRAT MNEMONIC	FIRST CORE DEPTH	STRAT MNEMONIC	FIRST CORE DEPTH
24 GRGT	7875.00						

REMARKS:

DEPTH TOP	DEPTH BASE	INT SUB	PERMEABILITY HORIZ MAX	PERMEABILITY HORIZ 90	PERMEABILITY VERTICAL	POROSITY	OIL	WATER	GAS	DENSITY	LITHOLOGY
7875.00	7879.00	<	0.05 PH								
7912.00	7914.00	<	0.05 PH			5.0 PE	2.1 PO	18.5 PW			SAND
7914.00	7916.00		0.34 PH			4.2 PE	0.0 PO	6.5 PW			SAND
7916.00	7923.00	<	0.05 PH			6.5 PE	1.7 PO	13.4 PW			SAND
7923.00	7928.00		0.18 PH			2.4 PE	0.0 PO	34.0 PW			SAND
7928.00	7930.00		0.59 PH			3.8 PE	15.4 PO	27.8 PW			SAND
7930.00	7931.00	<	0.05 PH			4.5 PE	4.3 PO	20.5 PW			SAND
7932.00	7935.00	<	0.05 PH			5.4 PE	0.0 PO	21.1 PW			SAND
						4.1 PE	2.8 PO	24.0 PW			SAND

BD	BULK DENSITY	PC	PLUG COMMON	PP	PLUG OF PERM SAMPLE	WE	WHOLE CORE EFFECTIVE	WS	WHOLE CORE SAT. SAMPLE
BG	BULK VOLUME GAS	PE	PLUG EFFECTIVE	PS	PLUG OF SAT. SAMPLE	WH	HORIZ MAX WHOLE CORE	WV	VERTICAL WHOLE CORE
BO	BULK VOLUME OIL	PG	PORE SPACE GAS	PV	VERTICAL PLUG	WO	WEIGHT BASE OIL	WW	WEIGHT BASE WATER
BW	BULK VOLUME WATER	PH	HORIZONTAL PLUG	PW	PORE SPACE WATER	WP	WHOLE CORE PERM SAMPLE	9H	HORIZONTAL 90 DEGREES
GD	GRAIN DENSITY	PO	PORE SPACE OIL	WC	WHOLE CORE COMMON	WR	RADIAL WHOLE CORE		

EXHIBIT NO. 11

Company: Northwest Pipeline Corp.
(Originally El Paso Natural Gas Co.)
Well: San Juan 31-6 Unit No. 16
Basin Dakota Field
SE/SW, Sec. 33, T31N, R6W
Rio Arriba County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7904.5-7905	.5	0.02
7905-7906	1	0.02
7906-7907	1	< 0.01
7907-7908	1	< 0.01
7908-7909	1	0.06
7909-7910	1	0.01
7910-7911	1	0.01
7911-7912	1	< 0.01
7912-7913	1	< 0.01
7913-7914	1	< 0.01
7914-7915	1	< 0.01
7915-7916	1	< 0.01
7916-7917	1	< 0.01
7917-7918	1	< 0.01
7939-7940	1	< 0.01
7940-7941	1	< 0.01
7941-7942	1	0.01
7942-7943	1	0.02
7957-7958	1	< 0.01
7958-7959	1	< 0.01
7959-7960	1	0.01
7960-7961	1	0.01
7961-7962	1	0.02
7962-7963	1	0.01
7963-7964	1	0.01
7964-7965	1	0.01
7965-7966	1	0.01
7966-7967	1	0.01
7967-7968	1	0.05
7978-7979	1	0.01
7979-7980	1	< 0.01
7980-7981	1	< 0.01
7981-7982	1	0.02
7982-7983	1	0.04
7983-7984	1	0.07
7989-7990	1	< 0.01
7990-7991	1	< 0.01
7991-7992	1	0.02
8005-8006	1	0.07
8006-8007	1	0.01
8007-8008	1	0.01
8008-8009	1	< 0.01
8009-8010	1	< 0.01
8014-8015	1	0.28
8015-8016	1	0.23
8016-8017	1	0.54
8017-8018	1	0.06

San Juan 31-6 Unit No. 16, cont.

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8022-8023	1	< 0.01
8023-8024	1	< 0.01
8024-8025	1	< 0.01
8025-8026	1	< 0.01
8029-8030	1	0.04
8030-8031	1	0.22
8031-8032	1	0.28
8032-8033	1	0.43
8033-8034	1	0.08
8034-8035	1	0.04
8035-8036	1	0.05
8036-8037	1	0.07
8037-8038	1	< 0.01
8038-8039	1	0.14
8039-8040	1	0.35
8040-8041	1	< 0.01
TOTAL	62.5	3.60

$\text{Avg. K} = \frac{3.60}{62.5} = \underline{0.058 \text{ md}}$

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

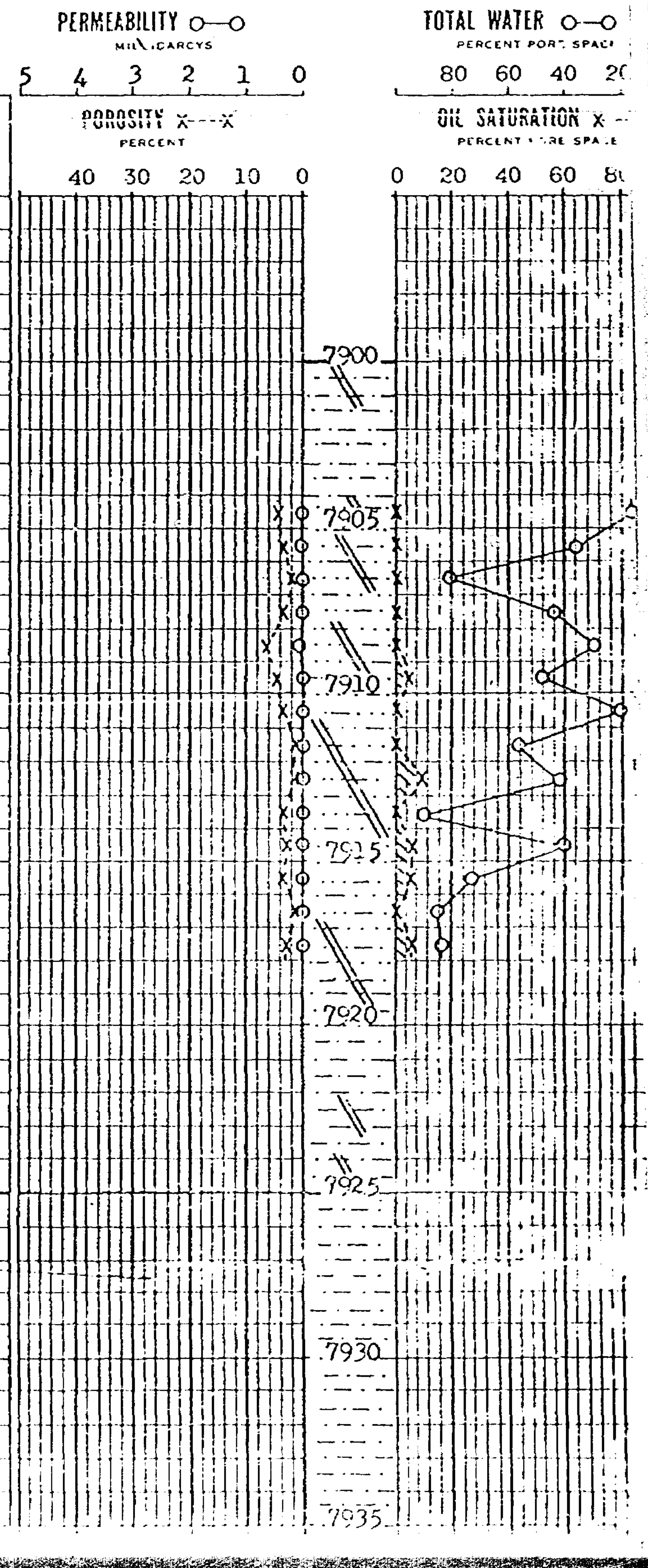
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 7/18/59 FILE NO. RP-3-1037
WELL SAN JUAN 31-6 NO. 16-33 DATE OFF 7/22/59 ENGRS. ENGLISH
FIELD WILDCAT (BLANCO MESA VERDE DAKOTA) FORMATION DAKOTA ELEV. 6499' DF
COUNTY RIO ARRIBA STATE NEW MEX. DRLG. FLD. OIL EMULSION MUD CORES DIAMOND
LOCATION SEC. 33-T31N-R6W REMARKS SAMPLED BY REPRESENTATIVE OF CLIENT.

SAND LIMESTONE CONGLOMERATE CHERT
SHALE DOLOMITE VERTICAL FRACTURE

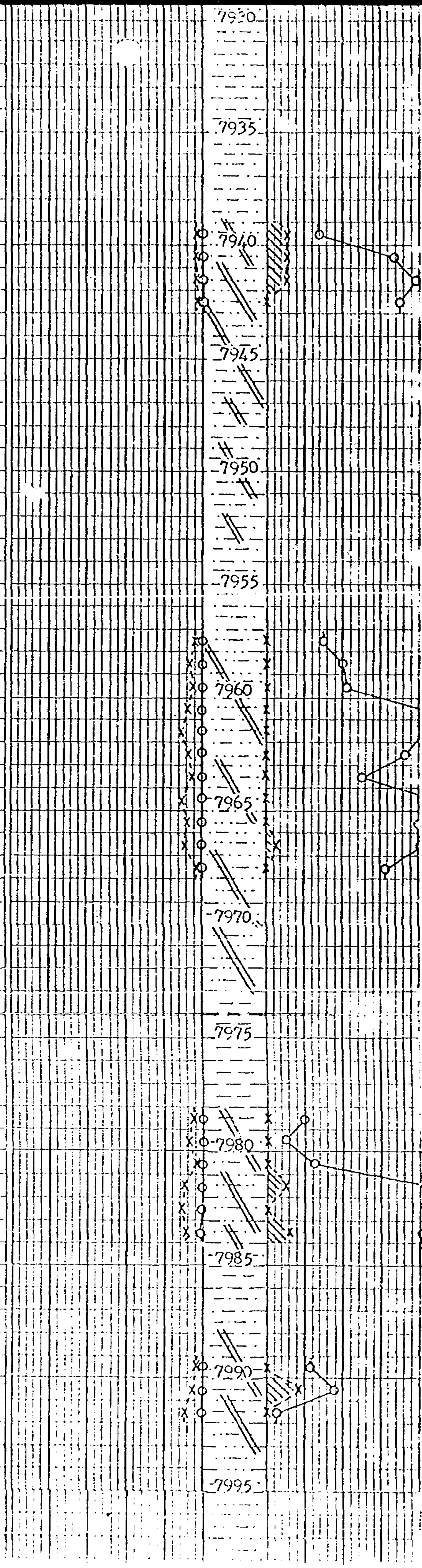
TABULAR DATA and INTERPRETATION

SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER		PROD
1	7904½-05	0.02	4.7	0.0	17.0		
2	05-06	0.02	3.8	0.0	36.8		
3	06-07	<0.01	2.1	0.0	81.0		
4	07-08	<0.01	3.6	0.0	44.5		
5	08-09	0.06	6.3	0.0	30.4		
6	09-10	0.01	4.5	4.4	48.8		
7	10-11	0.01	3.7	0.0	21.6		
8	11-12	<0.01	1.4	0.0	57.2		
9	12-13	<0.01	1.9	10.5	42.2		
10	13-14	<0.01	3.7	0.0	89.2		
11	14-15	<0.01	3.0	6.7	40.0		
12	15-16	<0.01	3.8	5.3	73.7		
13	16-17	<0.01	1.4	0.0	85.6		
14	17-18	<0.01	3.0	6.7	83.4		

COMPLETION COREGRAPH



15	7939-40	<0.01	1.8	11.2	72.1
16	40-41	<0.01	1.8	11.2	33.3
17	41-42	0.01	1.8	11.2	22.2
18	42-43	0.02	1.3	0.0	30.8
19	7957-58	<0.01	2.0	0.0	70.0
20	58-59	<0.01	3.3	0.0	60.6
21	59-60	0.01	2.4	0.0	58.3
22	60-61	0.01	3.8	0.0	15.8
23	61-62	0.02	5.6	0.0	17.9
24	62-63	0.01	3.7	0.0	27.0
25	63-64	0.01	2.8	0.0	50.0
26	64-65	0.01	5.4	0.0	11.1
27	65-66	0.01	3.9	0.0	20.5
28	66-67	0.01	4.1	4.9	19.5
29	67-68	0.05	1.6	0.0	37.4
30	7978-79	0.01	2.6	0.0	80.7
31	79-80	<0.01	3.7	0.0	89.2
32	80-81	<0.01	1.6	0.0	75.0
33	81-82	0.02	4.6	10.9	8.7
34	82-83	0.04	5.3	0.0	7.5
35	83-84	0.07	4.2	11.9	19.0
36	7989-90	<0.01	1.8	0.0	77.7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6



36	7989-90	<0.01	1.8	0.[illegible]	[illegible]7.7
37	90-91	<0.01	2.9	17.2	65.5
38	91-92	0.02	4.4	0.0	97.6
39	8005-06	0.07	1.0	0.0	40.0
40	06-07	0.01	1.2	0.0	58.2
41	07-08	0.01	0.9	0.0	66.6
42	08-09	<0.01	1.8	0.0	94.4
43	09-10	<0.01	1.8	0.0	94.4
44	8012-13	<0.01	3.6	5.5	80.6
45	8014-15	0.28	6.9	0.0	14.5
46	15-16	0.23	9.1	0.0	19.8
47	16-17	0.54	6.7	0.0	32.8
48	17-18	0.06	4.0	0.0	32.5
49	8022-23	<0.01	2.9	6.9	89.8
50	23-24	<0.01	3.2	15.6	81.3
51	24-25	<0.01	3.6	0.0	94.5
52	25-26	<0.01	5.2	0.0	90.4
53	8029-30	0.04	2.7	7.4	14.8
54	30-31	0.22	4.1	0.0	14.6
55	31-32	0.28	3.8	5.3	44.7
56	32-33	0.43	5.0	0.0	12.0
57	33-34	0.08	4.8	10.4	35.4
58	34-35	0.04	5.0	0.0	20.0
59	35-36	0.05	7.7	6.5	26.0
60	36-37	0.07	8.3	2.4	19.3
61	37-38	<0.01	7.6	2.6	21.1
62	38-39	0.14	6.1	3.3	26.3
63	39-40	0.35	6.2	0.0	19.3
64	8040-41	<0.01	7.4	0.0	21.6

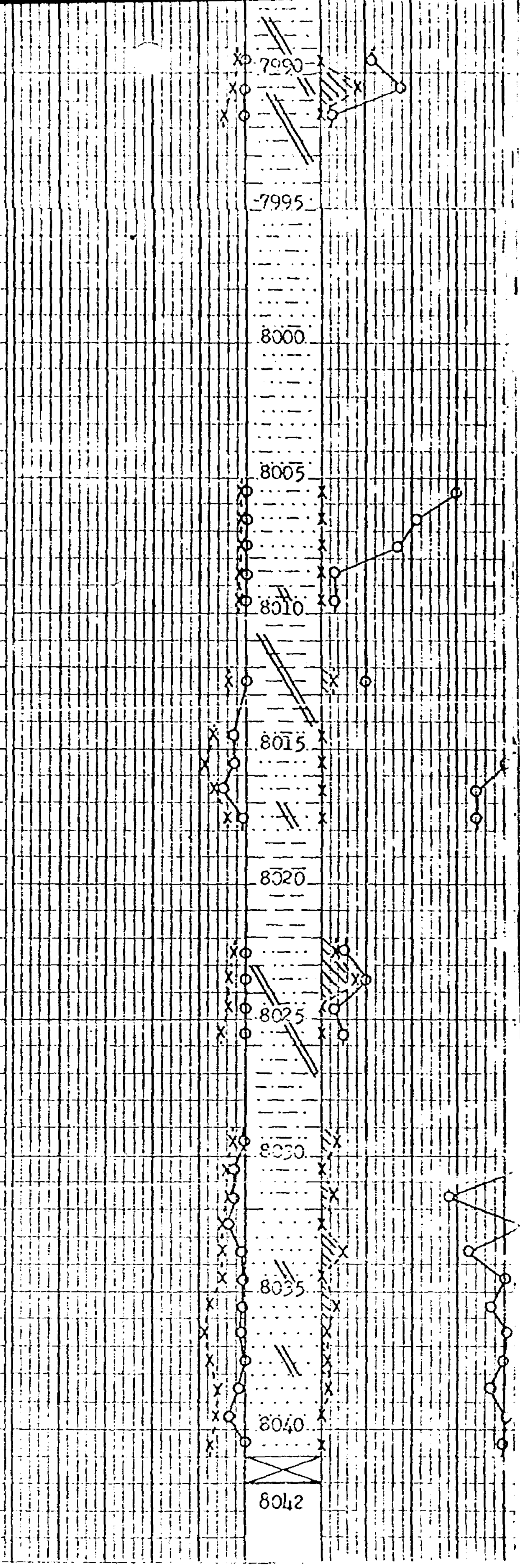


EXHIBIT NO. 12

Company: Blackwood & Nichols, Ltd.
Well: Northeast Blanco Unit No. 1
Basin Dakota Field
SE/NE, Sec. 27, T31N, R7W
San Juan County, New Mexico

DAKOTA FORMATION CORE DATA

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7831-7832	1	0.01
7832-7833	1	0.01
7833-7834	1	0.01
7834-7835	1	0.01
7835-7836	1	0.01
7836-7837	1	0.01
7837-7838	1	0.01
7838-7839	1	0.01
7839-7840	1	0.01
7840-7841	1	0.01
7841-7842	1	0.01
7842-7843	1	0.01
7843-7844	1	1.50
TOTAL	13	1.62

$$\text{Avg. } K = \frac{1.62}{13} = \underline{0.125 \text{ md}}$$

CORE DESCRIPTIONS

CORE #1 6990-7039. Recovered 21' blk. shale, bottom 6' sli sandy.

CORE #2 7039-7042. Core jammed in bbl. Recovered 2' blk shale.

CORE #3 7042-7045½. Core jammed in bbl. Recovered 3' blk shale.

CORE #4 7800-7830. Recovered 25 1/2'.

1. shale, gry-blk, platy, sli sandy, micaceous, tr coal
2. sand, gry, vfg, calc, sli silty, scattered mica., dnse
3. shale, blk, micaceous, w/scattered sand lenses, 15% sand
4. sand, gry, vfg, calc, very silty, shale stringers, abdt mica, dnse, tite.
5. same
6. same, 20% blk shale
7. shale and sand in alternating layers, predominately shale
8. shale, blk, sli sandy, calc, micaceous
9. same, w/pearly pelecypod frags
10. same
11. same
12. same
13. same
14. same, concentric fractures parallel to bedding
15. limestone, buff-brn, dnse, silic, crypto-xln, horizontal fractures
16. shale, blk, sli sandy, micaceous
17. same, concentric fractures parallel to bedding
18. same, no fractures
19. shale and sand in alternating layers, predom. shale
20. shale and sand in alternating layers, predom. sand
21. sand, gry-wh, fg, hard, dnse, scattered intergranular poro
22. same, sli silty, w/horizontal fractures
23. same, shaley (40%), micaceous
24. shale, blk, micaceous (75%); sand (25%)
25. sand, gry, fg, hard, micaceous, w/abdt pyrite
26. same (60%); shale (40%)

CORE #5 7830-7831. No recovery.

CORE #6 7831-7844. Full recovery.

1. sand, gry-wh, fg, hard horiz. frac, tr fair intergranular poro
2. same, w/thin shale partings, tr fair poro
3. same, no frac, tr fair poro
4. same, sli silty, tr fair poro
5. same
6. same, fair poro
7. same, tr fair poro
8. same
9. same

10. same
11. same, w/thin shale partings
12. same, tr fair poro
13. same, shale (20%), tr poro

CORE #7 7844-7844. Full recovery.
1. sand, gry-wh, fg, hard, tr intergranular poro
2. same, w/scat shale partings and horiz frac
3. same
4. same

---0---

ABBREVIATIONS USED IN SAMPLE & CORE DESCRIPTION

A - angular
abdt - abundant
bent - bentonite (itic)
blk - black
brn - brown
calc - calcareous
dnse - dense
fg - fine grained
foss - fossiliferous
frac - fractured
frag - fragment(s)
fx - finely crystalline
glau - glauconite(ic)
grn - green
gry - gray
horiz - horizontal
IGR - intergranular
incl - inclusions
lg - large grained
ls - limestone
mg - medium grained
poro - porosity
pyr - pyrite
qtzitic - quartzitic
R - rounded
SA - subangular
scat - scattered
sdy - sandy
sh - shale
silic - siliceous
sli - slight
SR - subrounded
ss - sandstone
tr - trace
V - very
vert - vertical
wh - white
xln - crystalline

CORE ANALYSIS DATA

CORE #6 - 7831-7844

SAMPLE NO.	DEPTH	PERMEABILITY MILLIDARCYS	NET POROSITY %	TOTAL POROSITY %
1	7832	0.01	4.20	4.65
2	7833	0.01	2.75	3.70
3	7834	0.01	4.10	4.42
4	7835	0.01	1.17	2.08
5	7836	0.01	1.97	2.81
6	7837	0.01	2.28	3.50
7	7838	0.01	3.08	7.80
8	7839	0.01	8.50	9.50
9	7840	0.01	7.20	7.90
10	7841	0.01	2.76	3.96
11	7842	0.01	2.65	2.93
12	7843	0.01	1.53	3.80
13	7844	1.50*	2.35	3.60

* This plug was taken across a natural, well bonded horizontal fracture.

EXHIBIT NO. 13

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

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.[5] 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,[1-3] causing greater reductions in permeability for low-permeability rocks.[2,4] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

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

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.

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 stanless 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 realistic 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-

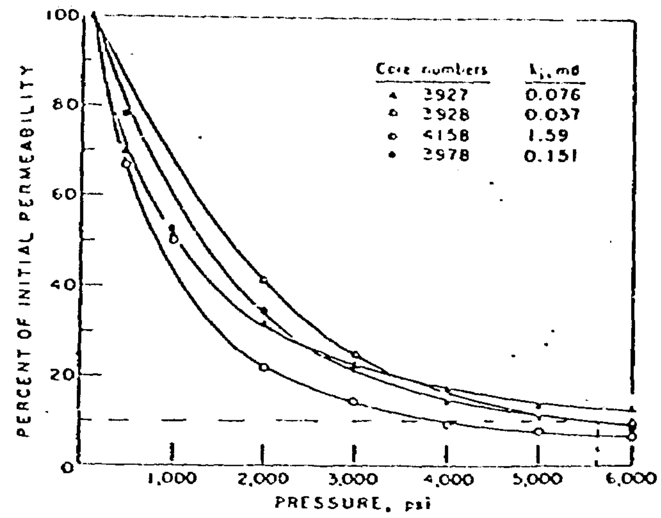


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

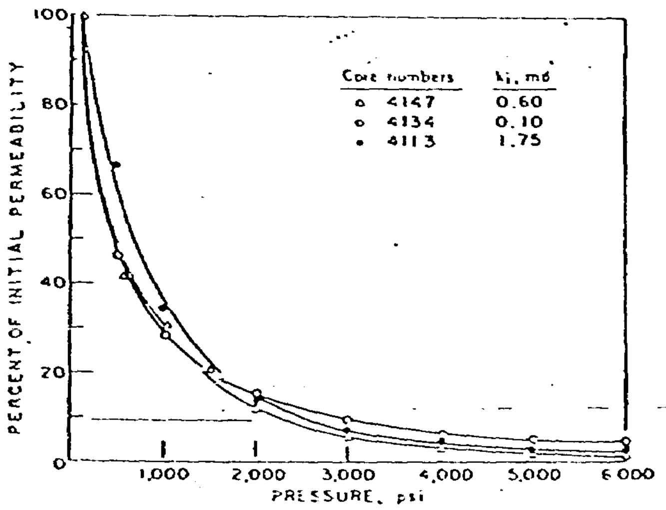


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

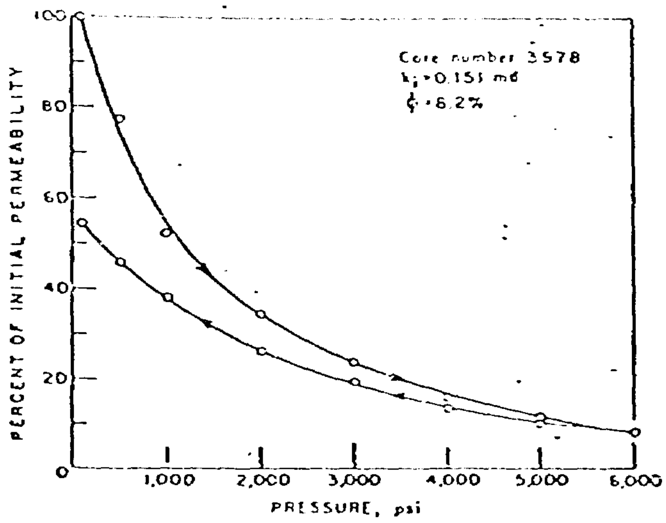


Fig. 3—Hysteresis effect at decreasing confining pressures.

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	[illegible]	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	0.016
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. 5 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	0.0006

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.

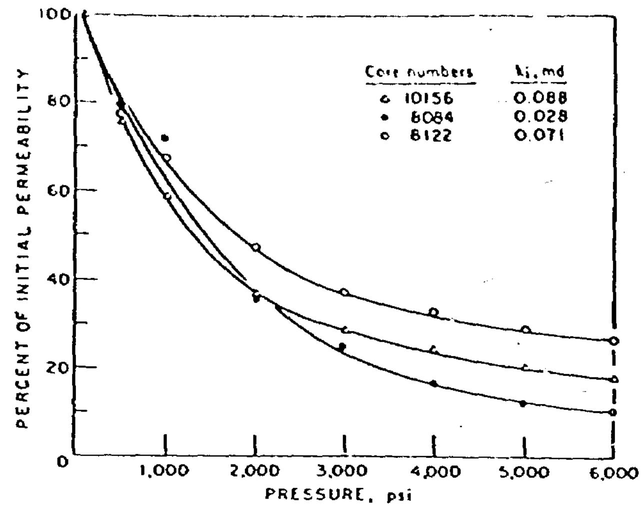


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

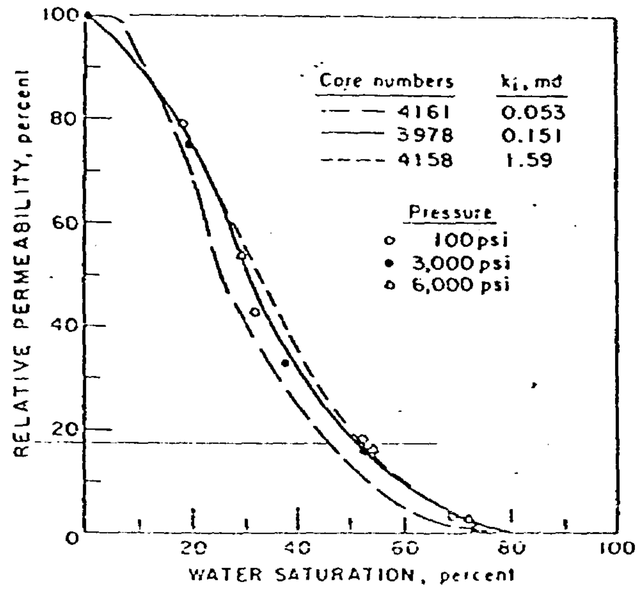


Fig. 5—Relative gas permeability of Gasbuggy cores.

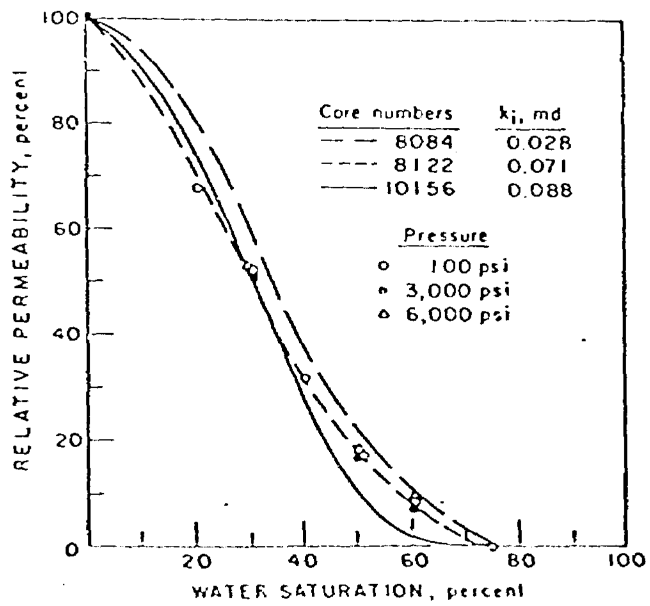


Fig. 6—Relative gas permeability of Wagon Wheel cores.

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

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.

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.

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.

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JPT

EXHIBIT NO. 14

DETERMINATION OF IN SITU FORMATION PERMEABILITY FROM LABORATORY CORE ANALYSIS DATA IN THE ROSA TIGHT GAS AREA

The relationship needed to determine in situ permeability from core analysis data is published in a technical paper by Rex D. Thomas and Don C. Ward entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", which is presented as Exhibit No. 13. The authors' studies involved taking routine laboratory air permeability measurements at the normal 100 psi or less external pressures. To simulate the effect of in situ conditions, these permeability measurements were then made at external pressures ranging from 500 to 6000 psi. The results of these tests were then plotted on a graph of Percent of Initial Permeability (ratio of permeability at 100 psi to a permeability at a higher pressure) vs. Pressure.

Figure 1, on Page 121, of Exhibit No. 13, is one such graph which presents results of tests run on cores taken from the Pictured Cliffs Formation. These cores were taken from Project Gasbuggy, located in Rio Arriba County, New Mexico. Cores from the Pictured Cliffs Formation and the Dakota Formation can be expected to provide similar results due to the low permeability characteristics of both sands.

The characteristics of core 3978, presented in Figure 1, can be used to represent the core data from the Rosa Tight Gas Area. The average laboratory air permeability from the Rosa Area was 0.124 millidarcy compared to an initial laboratory core permeability for core 3978 of 0.151 millidarcy. The confining pressure due to overburden at a depth of 7950 feet in the Rosa Area is approximately 5600 psi.

Entering the graph in Figure 1 at 5600 psi results in an 90% permeability reduction between laboratory determined permeability values and in situ permeability in the Rosa Area. Applying this 90% reduction to the average laboratory permeability of 0.124 millidarcy results in an average in situ permeability of 0.012 millidarcy for the Rosa Tight Gas Area.

The water present in the reservoir also causes the in situ permeability to be less than laboratory permeability as discussed in Exhibit No. 13. However, this correction will not be used in this case.

SUMMARY OF PERMEABILITY DATA

EXHIBIT NO. 15

	WELL	SAMPLE FOOTAGE TOTAL (ft.)	LABORATORY PERMEABILITY TOTAL (md)
1.	Northwest Pipeline Corp. San Juan 30-5 Unit No. 27	65.0	9.07
2.	El Paso Natural Gas Co. San Juan 30-5 Unit No. 28-X	87.7	11.66
3.	El Paso Natural Gas Co. San Juan 30-6 Unit No. 31	34.0	5.90
4.	Amoco Production Co. Rosa Unit No. 1	24.0	3.51
5.	Northwest Pipeline Corp. San Juan 31-6 Unit No. 16	62.5	3.60
6.	Blackwood and Nichols Ltd. Northeast Blanco Unit No. 1	13.0	1.62
	TOTAL:	286.2	35.36

Average laboratory permeability $= \frac{35.36}{286.2} = \underline{\underline{0.124 \text{ md}}}$

Average in-situ permeability (10% of laboratory) = <u>0.012 md</u>

EXHIBIT NO. 16

ROSA TIGHT GAS AREA

Natural Production Tests
(Pitot Tube)

	OPERATOR	WELL	LOCATION	NATURAL PRODUCTION TEST DEPTH	DAKOTA DEPTH	PRODUCTION RATE NATURAL (MCFPD)	PRODUCTION RATE AFTER FRAC (MCFPD)
1.	El Paso Natural Gas Co.	San Juan 30-4 Unit No. 39	SENW 18 30-4	8615	8425	527	2506
2.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 39	SWNE 7 30-5	7822	7686	161	1703
3.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 37	NESW 8 30-5	7870	7688	666	3944
4.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 49	SWSW 9 30-5	7780	7683	TSTM	855
5.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 73	NWNE 10 30-5	8035	7919	338	2635
6.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 72	SWSW 10 30-5	7905	7790	338	2456
7.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 53	NESW 16 30-5	7820	7685	264	1209
8.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 47	NWSW 17 30-5	7930	7794	2174	1610*
9.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 38	SWNE 18 30-5	7891	7667	128	2035
10.	Northwest Pipeline Corp.	San Juan 30-5 Unit No. 48	NWNE 20 30-5	7870	7790	370	3691
11.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 38	NENW 2 30-6	7970	7832	241	2828
12.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 36	NENE 27 31-6	7890	7806	TSTM	2557
13.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 35	NENE 35 31-6	8080	7908	338	2643
14.	Northwest Pipeline Corp.	San Juan 31-6 Unit No. 31	SESE 35 31-6	7928	7796	370	3770
			14 WELL AVERAGE			42[illegible]	2460
			13 WELL AVERAGE (Excluding Well No. 8)			288	2525

Natural Production Rate Limit for Tight Gas @ 7950 ft. is 336 MCFPD.

*Note after frac production rate is less than natural production rate.

EXHIBIT NO. 17

FOUR CORNERS GAS PRODUCERS
Rosa Tight Gas Area
Basin Dakota Field

Calculation of Initial Pre-Stimulation Flow Rates Using Darcy's Law

Darcy's Law: $$Qg = .703\ k\ h \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln(.61\ re/rw)}$$

where:

- Qg = gas flow rate - standard cubic feet per day
- k = permeability of formation - used average in situ value of 0.012 md from core data
- h = net pay - average of 42 ft. for wells completed in the Rosa Tight Gas Area.
- Pe = bottom hole pressure at drainage radius re - average of 3330 psi. from 7 day buildup tests run in the Rosa Tight Gas Area
- Pwf = flowing bottom hole pressure - assumed to be equal to atmospheric pressure at wellbore conditions, to determine maximum flowrate (14.6 psi)
- Ug = average gas viscosity - calculated to be 0.020cp
- T = bottom hole temperature - calculated to be 667°R
- Z = average gas compressibility factor - calculated to be 0.88
- re = drainage radius for 160 acre spacing - 1320 ft.
- rw = wellvore radius - .17 ft.
- gg = gas gravity - .7 - used for calculation of Ug and Z
- Pc = pseudo critical pressure - 668 psi. - used for calculation of Ug and Z
- Tc = pseudo critical temperature - 392° R - used for calculation of Ug and Z

$$Qg = .703\ (0.012)\ (42) \frac{(3330^2 - 14.6^2)}{(0.020)\ (667)\ (0.88)\ \ln(.61\ 1320/.17)}$$

Qg = 39,546 SCFGPD = 39.5 MCFGPD

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

26 August 1981

EXAMINER HEARING

IN THE MATTER OF:

Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico. CASE **7317**

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: **William F. Carr, Esq.**
CAMPBELL, BYRD, & BLACK P. A.
Jefferson Place
Santa Fe, New Mexico 87501

I N D E X

E X H I B I T S

MR. STAMETS: We'll call next Case 7317.

MR. PEARCE: Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, & Black, Santa Fe, appearing on behalf of the applicant.

This is a continuation of Case 7317 and I would request that the record show that Kevin McCord, who testified in the previous case, is qualified and that he is under oath in this matter.

MR. STAMETS: The record will so show.

KEVIN H. McCORD

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

DIRECT EXAMINATION

BY MR. CARR:

Q Mr. McCord, have you prepared additional exhibits for introduction in this case at the request of the Commission?

A Yes, I have.

Q Will you please refer to what has been marked for identification as Four Corners Exhibit A, identify this, and explain what it shows?

A In our previous hearing there was some question as to the quality of the Dakota formation in the eastern four townships, that being 30 North, 2 West; 31, 2; 30, 3; and 31, 3.

I have prepared some information to try and show that the Dakota formation exists and has the same or poorer qualities as the rest of the Rosa Unit.

Exhibit A is an electric log, the E. L. Poteet Monero Dome No. 1. This well is located Township 31 North, Range 1 West, Section 24, so it's off your map. It's approximately six miles to the east of the area, and what I'd like to point out on Exhibit A is on page four, tops of formations, the Greenhorn, Graneros, and Dakota, are shown, the Dakota being at 2300 feet.

My purpose of this exhibit is to indicate the Dakota is present. This is to the east of the area and there is Dakota to the west of the area. I'm assuming there is Dakota formation in between.

The Dakota being at 2300 feet, which is considerably different from the average of 7950 for the Rosa tight gas area. This is due to a steep upward trend of the formation there; we're coming out of the San Juan Basin in that area.

Q Mr. McCord, will you now refer to what has been marked for identification as your Exhibit B and review this for Mr. Stamets?

A Exhibit B presents core data from Rodney DeVilliers well, the No. 31 - 1 West Jicarilla. This well is located approximately four miles south of our four townships in question; location 29 North, 3 West, Section 21.

This presents the actual core analysis results on page two, and on page one is a summary of core analysis for this well.

This indicates that our laboratory permeability is 0.018 millidarcies and applying a 10 percent factor to this, which we considered for the rest of the Rosa Unit, results in a 0.002 millidarcy in situ permeability for this well.

I've also noted that a DST was run on this well when they were completing -- excuse me, when they were drilling it, and they estimated 15 to 20 Mcf of gas per day at the surface. I used this 0.002 millidarcy in my Darcy's Law calculation, as presented previously, and that resulted in a 9 Mcf per day flow rate.

This indicates the closeness of these

two ways of estimating natural flow.

Q Mr. McCord, have you also reviewed DS -- or cased hole DST's on wells located elsewhere but in this general area?

A Yes, I have. I've looked at a cased hole DST run by PanAm Corporation. This is the Jicarilla No. 1 Pagosa, which is located three miles north of our four subject townships, Township 32 North, Range 3 West, Section 23.

I reviewed this cased hole DST data, attempted a Horner plot on it, and I was not able to come up with any reliable permeability information from this well. The flow mentioned during this DST, I believe they recovered 90 feet of drilling mud, which calculates to virtually no flow of reservoir fluids at all; therefor, it was a dry hole, and it indicated this area was not productive.

Q Does Southland Royalty Company also have plans in the area?

A Yes, sir. At this time Southland Oil Company -- or excuse me, Southland Royalty is drilling the Sims Federal No. 1 Well, and this is in 30 North, 4 West, Section 13, and this is the northwest of the southeast. It is -- it was one of the wells I referred to last time as some of the new developments in the area.

Their current status, they are currently running a cased hole DST as of two days ago. Therefor, we don't have this information at this time. We will try to evaluate this information and supply it to the Conservation Division when we get this data available.

MR. CARR: Mr. Stamets, we would request that the record be held open to permit us to submit the written results of the Southland Royalty Company test as soon as it can be obtained. We had hoped to have it today, but they're doing it this week, and we'll get it to you as soon as it's possible.

MR. STAMETS: Okay, that would be fine.

A. Okay. Mr. Stamets, I'd like to point out that there were, other than the one dry hole mentioned previously in 30 North, 3 West, Section 34, a Sunray DX Oil Company Jicarilla Tribal No. 1, there were no other Dakota formation tests in these four townships; therefor, I have surrounded the area with the data I've just presented to you. This is virtually all we can come up with to try and tie this area into the rest of the Rosa Unit.

It's obviously a poor area. There's been no wells drilled in the area. The incentive prices will certainly help us to develop this area.

MR. STAMETS: So what you've given us today is basically three wells that form a triangle from 31,1, to 32, 3, to 29, 3, that seem to indicate that the Dakota formation is extant in those four townships, and that it is not any better than the formation evidence that you presented at the last hearing.

A. That is correct.

MR. STAMETS: Okay.

Q Mr. McCord, will you now refer to Exhibit C and review this for Mr. Stamets?

A. Exhibit C is an update of the new locations in the area, updating my map of figure -- of Exhibit Number Two, presented previously.

I've noted there that we have 19 wells with some sort of current activity as of August 6th of 1981. This is -- these 19 wells are listed on pages two and three of Exhibit C, and the appropriate information following them about what has been going on during this time period.

Page one, I've summarized wells not plotted on this map. As you'll notice there, we have 16 wells that have been drilled, 3 that have just been staked. Of these 16 as of August 6th, only 4 have been completed as -- as to IP data. We have three producers in the area and one dry hole. And this is just a written list of these new wells.

MR. STAMETS: All the IP's on here are after frac?

A. Yes, sir, they are.

MR. STAMETS: Did any of these wells make any attempts to determine pre-frac flow?

A. To my knowledge, no, they did not. It's possible, digging through some of Northwest Pipeline's records, we might be able to come up with some sort of pre-frac flow rate. My feeling is that that information would be no different from the information we've already got doing the same -- same procedures.

Q. Mr. McCord, of the three producers shown on Exhibit C, do all three of these appear to be -- look like they will be economic successes?

A. Well, we have the one dry hole, which obviously is not. We have one well, the well listed as No. 4, Northwest Pipeline 30-5 No. 50, with an IP of 735 Mcf of gas per day. My economics, which I'll show later, will indicate that that will not be an economic well under 103.

Wells -- Well No. 2, Schalk 54 No. 1-E, 2170 Mcf per day, and Well 18, Rosa No. 77 for an IP of 2544 Mcf of gas per day, also I'll show later these indicate to be indicative of an average well for the area, which is what I used in my economics.

Q. Mr. McCord, will you now refer to Exhibit D and explain to Mr. Stamets what this shows?

A. All right, Exhibit D was some information supplied to me by Mitchell Energy Corp. This information is supplemental to Exhibit Number Sixteen, presented previously.

Okay, Exhibit Number Sixteen indicates a number of pre-frac natural flow tests taken in the Rosa Tight Gas Area, mainly by Northwest Pipeline Corp. These wells are generally in 30-5 and 31-6. This information supplied by Mitchell Energy Corp., as you can see from the start, pre-frac, pre-stimulation rate tests are in 31-4, 31-5, in that area, so we're talking about the northern part of the area.

So we have additional information here. This 8-well pre-stimulation average that they referred to of 119 Mcf per day, refers to their eight tests that they've taken in the northern part of the Rosa Area.

Also here, K. McCord 14 well pre-stimulation average of 423, are my results as presented in Exhibit Number Sixteen. They've averaged the entire 22 wells for 312 Mcf per day average for a Rosa Well, and I also indicated in Exhibit Sixteen, and they have here, I excluded Well No. 8 in the average, in that its production, its natural production rate of 2174 Mcf of gas per day was higher than its after frac flow rate of 1610 Mcf of gas per day. I felt that this test was in error; therefor, I deleted it from my average.

They also did the same and came up with a 224 Mcf of gas per day average for the Rosa area.

Q What is the production limitation prescribed by the Oil Conservation Division rules for a depth of 7950?

A. This is 336 Mcf of gas per day, so we're below it.

MR. STAMETS: In either event.

A. In either event.

Just additional information to try and tie in more of the acreage, to indicate that my initial -- my additional information was holding throughout the area.

Q Will you now refer to Four Corners Exhibit E and review this for Mr. Stamets?

A. Exhibit E is the economic criteria requested by the Commission. I worked with Frank Chavez on these numbers and we came up with a production rate, listed there under No. 1, for an average Rosa Well throughout the entire area, Year 1 to be 330 Mcf of gas per day; Year 2, 205; Year 3, 145; Year 4, 115; and Year 5-on with an 8-1/2 decline in our yearly production.

This forecast was constructed by using an IP of 2100 Mcf of gas per day for Rosa -- for all the average Rosa wells, or for the entire Rosa wells in the area.

They averaged 2100 Mcf of gas per day. The first month average on-line production, being in the range of 15 to 20 percent, as I pointed out previously, being 420 Mcf of gas per day. Applying a decline rate of 40 percent for Year 1, 35 percent for Year 2, 25 percent for Year 3, 15 percent for Year 4, and 8-1/2 percent for year 5 on, results in a production rate shown under 1.

Also, this is a dry gas area, so no condensate production figures were used.

This type of production rate is indicative of the area and it also results in an average ultimate natural gas production of 0.691 Bcf for 33 wells tested in the area. This was the best average production we could come up with for the area.

Once again, using this average, you assume we have no dry holes at all in the area, so this will be a high side case on economics.

The average well life for a Rosa -- for a Rosa well would be 30 years. Natural gas prices used in our economics, we started with an NGPA 103 based price of July, 1981, and this was 2.476 dollars per Mcf of gas, and we used a 10 percent per year escalation rate.

We used a BTU factor of 1.15 and for the 107 price we used double the NGPA 103 price.

In figuring taxes we used the State and Local tax rate of 9 percent and Federal Income tax rate of 50 percent.

We considered to be -- we considered to have a Federal Oil and Gas Lease, using a 12-1/2 royalty to our government. Operating costs of $3000 per year, which will escalate at 10,000 per year.

MR. CARR: 10 percent.

MR. STAMETS: How about 10 percent?

A. Excuse me, 10 percent per year -- you can read better than I can . Overhead expenses of 20 percent investment and 20 percent of yearly operating costs, and a sales delay of six months.

Page two of my economics reviews that we have reserves of .691 Bcf over a 30-year well life.

At Mr. Chavez' request we ran the economics, determined payout, determined return on investment and present worth for the projects at 103 and 107 prices, in first Case 1 and Case 2, using no discount rate there for our money.

I presented two different well costs, one of $470,000 and one of $820,000. The reason I did this, Northwest Pipeline claims that a well can be drilled and produced in the -- drilled and fraced and ready for completion for $470,000.

Case 2, I believe, is a little more realistic. Amoco, the last three wells they have drilled, have been in excess of $800,000, and the four wells that Mitchell is currently drilling, the Rosa 81 through 84, they indicate those costs are going to be well over $800,000 a well.

So there's a difference in operating practices there.

Anyway, for Case 1, $470,000 well cost, using 103 prices, payout of 3.17 years, return on investment of 7.01, with a present worth of 1.869 million dollars.

When we look at 107 prices, our payout decreases to 1.68 years, return on investment of 16.32, and a present worth of 4.438 million.

Case 2, using an $820,000 well cost, 103 prices, our payout is 5.97 years, return on investment of 3.51, with a present worth of 1.662 million.

Using 107, our payout decreases to 2.77 years, return on investment of 8.74, present worth of 4.141 million.

Now, in Case 3, I attempted to use some type of discount factor to have somewhat more reasonable numbers. It's certainly going to cost us something to invest our money in this project. 15 percent discount, we might be looking at a high side due to today's economics. A number of 20, and Mitchell suggested 22 percent in what they use, might be a better indication of -- of the -- of what this project will actually result in.

Anyway, using a 15 percent discounted money, our present worth, discounted 15 percent for our $470,000 case, considerably drops to a $253,000 present worth, versus our initial 1.869 million.

When we look at 107's instead of 4.3 million dollar present worth, that drops to 808,000 dollars.

Therefor, when you use this discounted money, due to the 30-year life of the project, your economics change considerably.

This DROI number 15 is discounted return on investment and this is nothing more than our summation of our cash flows discounted 15 percent and divided by the well cost to give an indication of -- of what type of return on investment we'd be looking at discounted.

For $470,000 this number is less than 1, 0.54; for 107 it's 1.72.

The significance of this number, when this number is zero, that means you've -- you've gotten 15 percent back on your money.

Also presented for an $820,000 well case, which is what I believe is more indicative of the cost of the wells in the area, present worth 15 for 103 price is only $39,000. Our DROI 15 is 0.05. It -- we've just broken even there.

And with a 107 price, our present worth would jump to $593,000 with DROI 15, 0.72.

I would say that a DROI of 15 in the neighborhood of 1, would be something of an economical project. Anything less than that, you might be better off putting your money elsewhere.

Also, with Mr. Chavez' request, I contacted Amoco and they supplied us with some economics for their Gallegos Canyon infill wells, and I used these as a comparison to these Rosa wells to indicate what infill wells would look like using a 103 price for an established 103 economic area.

There were somewhat different parameters used. Our average well cost for these wells is approximately $420,000, and this was taken from ten infill well locations scattered throughout the Gallegos Canyon area.

B' factor used was 1.1. This is wet gas that they produce. We did not use a condensation -- or condensate production in our economics. Reserves for these wells, approximately 1.176 Bcf with a well life of 40 years.

103 prices, a payout of 2.73 years, return on investment of 16.04, and undiscounted present worth of $3,820,000.

When you use our 15 percent discounted numbers, present worth 15, $440,000, and discounted return on investment 15 of 1.05.

Comparing that with our $820,000 there is certainly quite a difference in the economics there.

Q Mr. McCord, it would appear, then, that the Gallegos Canyon infill wells are more economical to drill and produce than the Rosa area?

A. That is correct.

Q And all of these calculations are based on the assumption that you -- all the wells you drill are in fact producers?

A. Once again, yes, that's -- this is probably a high side because there are numerous dry holes in this area, and this assumes every well you drill will be a producer, producing .691 Bcf.

Q In your opinion, without the incentive price will the Rosa Area be developed?

A. No, sir, I don't believe it will. I believe that only wells that will be drilled under current 103 prices are the wells needed to -- to hold acreage in the area. I don't think it will be adequately developed without 107 prices.

Q. Generally, what conclusions now can you reach about the entire area which is governed by this application?

A. I'll just state again the conclusions I've drawn in my initial presentation.

The estimated average in situ gas permeability throughout our Dakota pay section in the Rosa Tight Gas Area is expected to be .1 millidarcy or less.

For an average Dakota well depth of 7900 feet, a stabilized production rate at atmospheric pressure of wells completed for production in the Dakota formation, is not expected to exceed the maximum allowable rate of 336 Mcf of natural gas per day without stimulation.

No well drilled in the Dakota formation in the Rosa Area is expected to produce without stimulation more than 5 barrels of crude oil per day; therefor, I believe that the Rosa Tight Gas Area meets all the specifications required as stated and should be designated a tight formation in the Basin Dakota Pool under Section 107 under the Natural Gas Policy Act of 1978.

Q. Mr. McCord, were Exhibits A through E compiled under your direction?

A. Yes, all but Exhibit D, which was, as I stated, presented to me by Mitchell Energy Corp.

Q And your -- does your review of these exhibits indicate that they are correct and accurately portray the data you are attempting to show?

A. Yes, they do.

MR. CARR: At this time, Mr. Stamets, we would offer Exhibits A through E.

MR. STAMETS: These exhibits will be admitted.

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

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. McCord, Exhibit E, the last page of your economic exhibit.

A. Yes, sir.

Q In Case No. 1 you're looking at what you consider to be the lowest possible well cost in the area?

A. That is correct.

Q And does your 107 situation mean that you could do -- that this is comparable to putting your money in a money market certificate with 16.32 percent interest?

A. No. Your return on investment numoer is not a percentage. That's -- that number is generated by taking your total cash flow generated divided by your well cost.

So your return on your investment, you're getting 16 times the money you spent, is what that number means.

That is not a percentage.

MR. CARR: Over thirty years.

A Yes, and that's over thirty years, also.

The percentages involved are your discounted return on investment that I have presented, and what this number indicates, since I have discounted it at 15 percent, that means any number over zero will give you a -- any number greater than zero will give you more than a 15 percent return on your money, and assuming you can get 15 percent in the bank or anything to that, it's certainly a lot -- a lot better proposition to put your money in the bank and get it back that way.

Q Can you convert, for example, in a 103 situation, the 0.54, can you convert that into a percentage rate of return?

A Not from the figures I have here. These were the numbers supplied to me by Amoco. I don't have their printout. This was information that they considered confidential and did not want to present unless we -- we absolutely had to.

We can confer from that DROI 15 number that your return would be less -- excuse me, somewhat more than 15 percent, but the actual number, we don't have.

MR. STAMETS: Other questions of this witness?

MR. CHAVEZ: Yes, sir.

QUESTIONS BY MR. CHAVEZ:

Q Mr. McCord, in a discounted rate of return what does the absolute number zero indicate? Does that indicate a break even point?

A. Yes, it does.

Q At 15 percent.

A. That's right. That would mean that your money is worth -- all that is doing is taking your future monies and bringing it to the present.

Q Okay. The average depth for the Dakota in these townships, how did you arrive at that again?

A. I -- every well involved in the area, I took the top of the Dakota formation and we averaged that number.

A. Okay. But in the far eastern townships the slope of the Dakota is quite a bit steeper and the Dakota formation is at about 2300 feet.

A. Now, that, once again, that well is outside of the formation -- outside of the area. Now, the actual -- you're right, it is going up at a steep angle there. Where it exactly turns, we need to have a well out there to -- to show us where the Dakota is. I don't know that.

Q. Can you make some kind of projection as to the rate of dip which the -- or rate of rise towards the east throughout --

A. Not other than it's very steep. It -- it comes up real fast, and that's just -- I have not worked that much with the geology in that area.

Q. Would work such as that give you an average Dakota depth which might be shallower than what you'd use for where wells were completed and thus require a smaller volume of unstimulated flow rate?

A. That is possible, although not -- it would be -- it's my feeling we've got most of our area over here established and all our wells are established, are somewhat deeper than that. We have a small portion of our area over here to the far east that might be possibly shallower than that. If we take an average, it could bring that number down, but once again, if you weighted your average, your number would certainly be very close to what we've got. This would not be a great percentage of these wells.

Q Do you know what depth the Southland Royalty Simms Federal Well encountered the top of the Dakota?

A. No, sir, but we'll know that when we get our information. That's -- that well, they just moved the drilling rig off of it. They, in fact, they were trying to speed up their completion to get this DST data to present for this hearing, so we will have that information then.

MR. CHAVEZ: I have no further questions.

RECROSS EXAMINATION

BY MR. STAMETS:

Q Mr. McCord, in Case No. 1 on Exhibit E, is that an economic venture at the 103 price?

A. Under the 103 price that would be a very marginally economic venture. Once again, looking at your discounted return on your investment 15, that being 0.54, it's in the range between zero and one, which makes it questionable. Due to the fact, knowing how these economics were arrived at, being an average well where you drill no dry holes, you'll get .7 Bcf, it would marginally economic as it is there.

If you consider everything involved, the real chance that you could drill a dry hole, those numbers are not really realistic; they're the high side. So therefor, I would say that if it was economic, it was just on the margin of it.

The more -- the more common cost of $820,000, or more indicative cost, that's -- that's not economic, no.

Q And the return on investment means that you get back $7.00 for every dollar you spent over a period of years?

A Yes, sir, that's correct, over thirty years. There's a time -- that time factor means an awful lot when you consider discounted money.

Q And if you put your money in a 15 percent money market certificate, or some such thing as that, you would -- would you be making more money than drilling this well?

A Under 103, $470,000 case, you would make more money drilling the well.

If it was $820,000, you'd break even. So you'd be a lot better off putting your money in the bank.

Once again, assuming you have a commercial well, not a dry hole. That -- that factor is always going to be involved, because we're talking average well, and there are dry holes in the area.

The only way to counter that effect is use a success factor or to greatly increase the cost of your wells. It's something to take into account, the cost of dry holes, which would even decrease our economics even more.

Q How does Northwest Pipeline drill such economical wells?

A I've had that asked to me quite a few times. They have somewhat different completion practices than, say, Amoco would, but other than that, they're doing it real cheap.

Q Does Amoco management know about the engineering of Northwest Pipeline?

A Well, since we have a lot of Amoco management here, I would prefer not to talk about it.

I'm sure they -- they probably know that, but once again, you've got a difference in philosophy of companies on how to complete these wells. Some people feel that large fracture treatments, large volume treatments, are the way to go. Other companies, such as Northwest, feel you don't need to go to all that trouble.

I guess time will tell with thirty years of Dakota well production which is best.

But other than that, it's -- it's just

a difference in philosophy of the companies.

Now that's just the stimulation costs, is a big factor there. That certainly doesn't account for all the difference in those costs. Those are just the costs reported to me.

Q It sounds to me as though what you're saying is, that if -- if Northwest Pipeline were the operator of this entire area, and they got the 103 price, they'd be able to drill it up and make money.

A. If they got the 103 price?

Q Right.

A. If they drilled no dry holes. If they did, if they drilled dry holes, it's marginally economic right now, as presented in Case 3.

Like I said before, I feel that a DROI number less than one is somewhat questionable economics in whether you should be drilling that, because there are -- there are success factors involved.

Q So the Exhibit E estimates that every well will be a producer and does not try to take into account a certain number of dry holes in respect to the average recovery for the entire area.

A. Correct. Once again, the way to do that, or to incorporate that type of number, would -- would be to acre spacing. Other than two instances there have not been any infills drilled.

So companies don't feel it's that economical of a venture to be drilling more wells in the area.

Q. Do you feel that the ratio of dry holes will increase as you move west and east out of this central area?

A. Yes, greatly.

Q. I don't recall from the original hearing if there was any geologic evidence that was indicating that there is a fairway or something through here that was being drilled up, or these wells are simply being drilled because of GEological Survey demands on drilling, or is this where the older wells were and these wells are being drilled as stepouts.

A. I would say more in the stepout area. I don't remember presenting any fairway type areas that we -- that you just referred to. Most of these are older wells. They're stepping out, trying to, really, just -- just satisfy your unit agreement, and some type of drilling to have an adequate development of the area.

Q. In Case No. 1, with the 103 pricing, what percentage of dry holes would it require to be drilled before that process became uneconomical?

considerably increase your well costs or incorporate some type of success factor there. But once again, using this -- this type of approach, comparing the actual economics we found right here versus our Gallegos Canyon well, it shows a considerable difference in the two projects.

Q Looking at the original Exhibit Two, it appears, though, there aren't too many dry holes through the central north/south portion of the area, at least in comparison to the numbers, percentages both east and west of there, is that correct?

A. Yes, that is. My feeling there is that these are all areas held by units and to develop these units and to show to the USGS that they're adequately trying to develop these units, wells are going to have to be drilled.

Under the current pricing scheme, we certainly have less chance of finding a dry hole in this area versus drilling our exploratory wells and developing the entire acreage. I believe that's why there's been a considerable number of wells drilled in this area versus the rest of it. I think that to develop your outer areas we're going -- we're going to need some type of price incentive to have this done.

Also, another fact, these wells in the -- in the middle part of the area developed essentially on 320-

A. It wouldn't take but one, probably.

Q One in four, one in five, one is three, one in two?

A. I imagine, at a guess, you could probably say one in eight, as far as that goes. You're talking here, once again, looking at your discounted return on investment numbers, it's marginal now assuming no dry holes. Just say using a dry hole will increase your initial well cost from $470,000 up, well, you see that doubling that money right there brings it down to just a break even point there.

So that would take, what, one dry hole in -- let's see, one dry hole in two, wouldn't it?

Q Uh-huh. That would mean that if you had got every other hole a dry hole, it would be a break even proposition. So what would that, say, if you had one dry hole in four, it would be a money making proposition?

A. Considering that $470,000 that sounds reasonable, yes. Once again, though, that's one instance where they claim they can drill it for that -- that type of money, and we have -- and that was just a number presented to me and the last seven wells, or the last three wells Amoco has drilled and the last four wells Mitchell has drilled in the area cost $800,000, so therefor, considering that $470,000 well cost for those, it's not reasonable at all.

MR. STAMETS: Are there any other questions of this witness? Mr. Kendrick, back in the hall, we'll give you a turn.

QUESTIONS BY MR. KENDRICK:

Q Mr. McCord, the cost of development figures that you've given in the range of $400,000 to $800,000, relates only to drilling and completing the well, has no secondary recovery or, excuse me, secondary or remedial action numbers involved.

A. That's correct. Another -- the only numbers involved are therefor operating costs or just what we've used here.

We've used $3000 per year escalating at 10 percent as straight operating costs.

We've also include overhead expenses of 20 percent of investment and 20 percent of yearly operating costs, so those are also involved as expenses for the well, but no -- no remedial work.

Q If remedial action were required on one of the classes of wells, would you expect it to be needed on the cheaper original cost or the more expensive original cost?

A. That's a good question. This could be a personal feeling, but I personally think that -- that you need to put more of a fracture stimulation on these wells, which would increase your cost.

Using that as the only basis of the difference in the costs, I know there's something else involved there, too, but my feeling is that in the life of the well, this would certainly be a better completion practice to use.

But if the $470,000 well cost had a somewhat smaller size fracture stimulation, it's possible that this well might need the remdial work more than the $800,000 well, bringing up the cost.

MR. STAMETS: Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q. Mr. McCord, has Southland Royalty apprised you of their AFE cost for the Chacosa Canyon No. 1 or for the Simms Federal 1 that they are presently testing, of what their costs have been to date?

A. I haven't asked for that information but that should be easy enough to get, especially since they're going to supply us with this other information. I'm sure they'd more than happy to supply us with an AFE.

MR. STAMETS: Good, you can supply that along with the other information.

Any other questions?

MR. PLUMLEY: Yes, sir.

MR. STAMETS: Identify yourself for the record, please.

MR. PLUMLEY: I'm Byron Plumley, with Atlantic Richfield, out of Denver.

I'd like -- there was a telegram sent yesterday, I think, to the Commission, and I would like to reiterate that.

ARCO has reviewed and agrees with this application, and that ARCO would urge the Commission to approve of this application.

MR. STAMETS: All right, we appreciate that.

If there are no further questions, Mr. McCord may be excused.

Are there any other statements?

With the provision for the other information that we've discussed here, the case will be taken under advisement.

(Hearing concluded.)

CERTIFICATE

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

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INDEX

E X H I B I T S

MR. STAMETS: The hearing will please come to order.

We'll call at this time Case 7317.

MR. PADILLA: Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, Santa Fe, New Mexico, appearing on behalf of Four Corners, and I have one witness.

We would also like to enter our appearance at this time for Gary Paulson, an attorney for Amoco out of Denver.

MR. STAMETS: Any other appearances in this case?

MR. KELLAHIN: If the Examiner please, I'm Tom Kellahin, Santa Fe, New Mexico, appearing in association with Mr. Larry Pain, an attorney for Phillips Petroleum Company.

MR. STAMETS: Any other appearances?

MR. PAULSON: Yes, sir, Gary Paulson Amoco Production Company, appearing in association with Mr. Carr.

We do have a supporting statement to make on behalf of the application.

MR. STAMETS: Does anyone else have an appearance? Any other witnesses in this case?

I'd like to have the witness stand and be sworn at this time, please.

(Witness sworn.)

KEVIN H. McCORD

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

DIRECT EXAMINATION

BY MR. CARR:

Q Will you state your name and place of residence?

A. My name is Kevin H. McCord and I live in Farmington, New Mexico.

Q By whom are you employed and in what capacity?

A. I am self-employed. I'm a self-employed petroleum engineer acting as a consultant for the Four Corners Gas Producers Association.

Q Have you previously testified before

this Commission or one of its examiners and had your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, I have.

Q. Are you familiar with the application of Four Corners Producers Association in this case?

A. Yes, I am.

Q. Are you familiar with the subject area?

A. Yes.

MR. CARR: Are the witness' qualifications acceptable?

MR. STAMETS: They are.

Q. Mr. McCord, will you briefly state what Four Corners Gas Producers Association seeks with this application?

A. The Four Corners Gas Producers Association is applying for a portion of the Basin Dakota gas field to be designated as a tight formation under Section 107 of the Natural Gas Policy Act of 1978.

The proposed Rosa tight gas area is located in the northeastern portion of the San Juan Basin. The area is approximately 25 miles northeast of the town of Bloomfield in northwestern New Mexico, and covers portions of Rio Arriba and San Juan Counties.

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

A. I have.

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

A. Yes, they have.

Q. Will you please refer to what has been marked for identification as Applicant's Exhibit Number One and explain to Mr. Stamets what this is and what it shows?

A. Exhibit Number One displays the Rosa tight gas area on a map of the Dakota reservoir in the San Juan Basin. The Rosa area includes approximately 270,260 acres in Townships 30 and 31 North, Ranges 2 through 7 West.

Q. Will you now refer to Exhibit Two and review this for the Examiner?

A. Exhibit Number Two is a Dakota formation completion and production map of the proposed Rosa tight gas area. The production figures presented for each producing well are initial potential, date of initial potential, average daily production for 1980, and January 1, 1981 cumulative production of gas and oil.

Exhibit Number Two also presents completion and production data from wells surrounding the proposed tight gas area. The Rosa tight gas area contains 53 producing Dakota formation gas wells, while 14 wells in this area are abandoned in the Dakota at this time.

A list of these wells and their production figures is presented as Exhibit Number Three. Examination of these figures indicate that these Dakota wells have not produced great quantities of natural gas, suggesting that low permeability reservoir rock could be present in the area.

Q Now, Mr. McCord, will you please refer to Applicant's Exhibit Number Four and review this for the Examiner?

A. Exhibit Number Four is a type log of a Dakota well found in the Rosa tight gas area. This log is from the Northwest Pipeline Corporation Rosa Unit No. 68 Well, found in Section 17, Township 31 North, Range 5 West. This well is in the north central section of the Rosa tight gas area.

The type log shows the entire Greenhorn and Dakota formations and part of the Mancos and Morrison formations.

The type log shown is in a part of the Rosa tight gas area which has exhibited better producing characteristics than the remainder of the area. Wells in the remaining sections of the Rosa area would be expected to have the same or poorer log characteristics than this type log.

Q. How is the Dakota formation defined by the Oil Conservation Division?

A. The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 400 feet below the base of the Greenhorn. The formations covered in this 400 feet are the Graneros Shale, Dakota Sandstone, and Morrison formations.

The Dakota formation is productive in this area while the Morrison formation is generally water-bearing. Sands in the Graneros Shale are not adequately developed in this area to be productive.

Q. Mr. McCord, what is the average depth of the Dakota formation in the area which is governed by this application?

A. 7950 feet.

Q. And what is the gross thickness of the formation?

A. Approximately 250 feet.

Q. Could you generally describe the geological characteristics of the Dakota?

A. It's generally, let's see here, the Dakota consists generally of barrier beach deposits about 40 to 60 feet thick. This is the Upper Dakota. Composed of fine grained, quartz rich sandstones characterized by an increase in grain size upward and low angle crossbedding.

The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones, and sandstones. This unit represented a lagoonal type environment.

The basal Dakota was deposited by a system of meandering streams creating deposits of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstones.

Q. Will you now refer to what has been marked Applicant's Five and Six and explain what these are and what they show?

A. Exhibit Numbers Five and Six are log cross sections through the Rosa area showing the continuity of the Dakota formation using the base of the Greenhorn formation for a datum line.

Q. Now, Mr. McCord, when I look at your Exhibit Number Two, is there any control in the Dakota on the east side of the subject area?

A. No, sir, there's not. There's been

very sparse drilling in that area. Only one well was drilled and that would be in Section -- or Township 30 North, Range 3 West, Section 34. A Dakota well was drilled by Sunray DX Oil Company, Jicarilla Tribal No. 1, in September of '64. It was drilled and abandoned.

Other than that there is no control to the east part of the area.

Q. In your opinion is the Dakota continuous across the basin?

A. Yes, it is.

Q. What is the porosity range within the area governed by the application?

A. Overall the Dakota sand has a porosity range of from 1/2 percent to 11-1/2 percent in the Rosa area, with the average pay porosity being in the neighborhood of 4 to 6 percent.

Q. Is the in situ permeability cutoff in the Rosa tight gas area less than .01 millidarcy?

A. Yes, it is. The formation is dependent upon stimulation techniques to be commercially productive.

Q. And have you calculated permeability for the area?

A. Yes, I have.

Q. Would you please refer to Applicant's

Exhibits Seven through Twelve and review these for Mr. Stamets?

A. Okay. Exhibits Numbers Seven through Twelve present core analysis data used to determine the average laboratory permeability to air for Dakota formation pay zones in this area. The exhibits contain the actual core analysis reports, plus summary tables, showing the analysis of cores taken from only the productive portion of the Dakota formation for each well. The cored intervals chosen for permeability averaging were determined by log examination of the interval cored for each well. Only cored intervals of sand with more than 10 ohms resistivity appearing on the induction resistivity log of the well were used for permeability averaging. This 10 ohms resistivity cutoff represents the average resistivity shown by the shale sections on the logs. Values less than this cutoff were not considered to be pay zones.

The average laboratory permeability to air determined for the Rosa area in this manner was 0.124 millidarcy. The actual in situ permeability of the formation is less than this laboratory determined value, mainly due to the confining pressures found in the Basin Dakota reservoir.

Q. Will you now refer to and identify what you have marked Applicant's Exhibit Thirteen?

A. Exhibit Number Thirteen presents a

technical paper entitled Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores, which was written by Rex D. Thomas and Don C. Ward of the U. S. Bureau of Mines.

This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs.

Exhibit Number Fourteen explains how in situ permeability is calculated from the core analysis, using the technical paper presented.

Q. Will you now refer to your Exhibit Number Fifteen and explain this exhibit?

A. Exhibit Fifteen is a summary of all laboratory core analysis results for the Rosa tight gas area. An average in situ permeability value of 0.012 millidarcy was calculated from the average laboratory permeability value of 0.124 millidarcy for the Rosa area. This in situ permeability value is well below the 0.1 millidarcy tight gas cutoff. These permeability measurements substantiate that the Dakota formation is very tight in this area and must be stimulated to obtain commercial gas production.

Q. Mr. McCord, can gas be produced in commercial quantities from the formation in the subject area without stimulation?

A. No, it cannot.

Q. Now I believe you stated that the average depth of the Dakota in this area was 7950 feet. What is the maximum stabilized production rate against atmospheric pressure allowed for wells in the subject area in this depth by the Oil Conservation Division rules?

A. 336 Mcf of gas per day.

Q. Have you obtained stabilized unstimulated gas production rates for Dakota wells in the area?

A. Yes, I have. Obtaining stabilized unstimulated gas production rates for Dakota Wells is not a standard procedure used by companies when completing their wells in the San Juan Basin. Past experience has shown that these lower permeability Dakota wells must be stimulated to obtain commercial production; however, some wells drilled in the Rosa tight gas area were drilled with gas as a circulation medium through the Dakota formation. This drilling procedure enables unstimulated natural gas from the Dakota formation to rise to the surface while drilling the well. Unstimulated natural production tests can be taken while drilling with natural gas when the gas used for circulation is shut off and the pipe rams closed on the blowout preventer stack. This enables the injected gas to go down through a bleedoff line to the reserve pit.

After injection gas has sufficient time to return to the surface any further gas production through this line should be unstimulated gas production from the well. A gas measuring device, such as a pitot tube placed in the center of the natural gas production stream, is used to measure the natural gas flow rate from the well. A pitot tube measures the impact pressure of the gas flow rate, which is used to determine the velocity of the gas. This gas velocity combined with the known area of the blowoff line is used to calculate the flow rate of the gas through the line.

Natural unstimulated gas production tests performed in this manner were found for 14 wells in the Rosa area. The results of these unstimulated gas production tests are presented in Exhibit Sixteen. These gas flow rates range from rates too small to measure to 2174 Mcf of natural gas per day. The average unstimulated gas production rate is 423 Mcf per day. This value is larger than the 336 Mcf per day limit for tight gas at an average depth of 7950 feet. On an individual well basis six wells meet the unstimulated natural production requirement with three wells just at the limit and five wells being over the 336 Mcf per day limit.

Testing natural gas wells in this manner is not very accurate but it can give the tester some idea if a well will be gas productive or not. The exact nature of these tests have many factors which leave their results questionable.

The Mesaverde formation is also productive in the tight gas -- in the Rosa tight gas area. While the Dakota formation is open to flow to the surface during the natural flow test, the overlying Mesaverde can also be producing at the same time. There is no way to separate the production from each zone using a natural production test conducted in this manner.

Also, the length of these unstimulated production tests are not long enough to establish a stabilized production rate. This length of test can by no means be considered to be a stabilized production test of the well's productivity.

Also, the natural gas injected into the well for circulating purposes can also cause erroneous results if this gas is still returning to the surface while the test is being taken.

It is reasonable to assume that the three test uncertainties presented could all contribute to make unstimulated production tests performed in this manner report erroneously high production rates. This assumption is supported by well production data presented in Exhibit Sixteen. The well listed as number eight, the Northwest

Pipeline Corporation San Juan 30-5 Unit No. 47 Well, shows an unstimulated natural gas production rate of 2174 Mcf per day. After fracturing, the initial production for this well is 1610 Mcf per day. The initial potential for a well is calculated from a 3-hour flow test following a 7-day pressure build-up, which is a more controlled and accurate test than the pitot tube test.

This, combined with the fact that an after-frac production test should definitely not be lower than the unstimulated production test, indicates the unstimulated production test is probably in error.

Exhibit Sixteen also presents a 13 well average unstimulated production rate, which includes the erroneous rate found -- excuse me, whic excludes the erroneous rate found for the San Juan 30-5 Unit No. 47 Well. This 13 well average rate is 288 Mcf per day, which is below the 336 Mcf per day rate limit for tight gas determination in the Rosa area.

Due to the uncertain nature of the unstimulated production rate testing process, this 288 Mcf per day production rate, while being below the tight gas guideline, is still thought to be higher than the actual average unstimulated gas production rate for the area.

Q Have you calculated the unstimulated gas flow rate using the in situ permeability value of .012 millidarcies?

A. Yes, I have. In order to test the validity of this natural production figure, Darcy's Law was used to calculate an unstimulated gas flow rate using the average in situ permeability value of 0.012 millidarcy calculated for the Dakota formation in this area from core analysis study.

Exhibit Number Seventeen presents this calculation and shows that an initial unstimulated gas flow rate of 39.5 Mcf per day is associated with the average in situ permeability of 0.012 millidarcy for the Rosa area.

The calculated unstimulated gas production rate and the average actual unstimulated gas production rate, excluding the erroneous production rate mentioned previously, are both less than the 336 Mcf per day limit for a tight gas reservoir in the Rosa area. As a result of these calculations the unstimulated natural gas production rate from the Dakota formation in the Rosa area is not expected to exceed 336 Mcf of gas per day.

Q. Do you have any unstimulated oil production figures for this area?

A. Yes. The natural gas produced from the Rosa tight gas area is virtually dry gas, having very little, if any, oil or condensate production associated with it.

Exhibits Number Two and Three show that only one well, the natural -- excuse me, the Northwest Pipeline Corporation Rosa Unit No. 56, has reported any oil production associated with its gas production.

MR. STAMETS: What's the location of that well?

A. Okay, Section 35, 31, 5.

MR. STAMETS: Okay.

A. This well has only produced 26 barrels of oil since 1976. These dry gas production figures indicate that no well drilled in the Rosa tight gas area is expected to produce without stimulation more than 5 barrels of crude oil per day.

Q. Mr. McCord, will the production of hydrocarbons from the subject area impair fresh water supplies in this area?

A. No, they will not.

Existing State and Federal regulations will assure that development of a Dakota formation will not adversely affect or impair any fresh water aquifers that are being used or expected to be used in the foreseeable future for domestic or agricultural water supplies. Regulations require that casing programs be designed to seal off potential water-bearing formations from oil and gas producing formations.

These zones, these fresh water zones exist from the surface to the base of the Ojo Alamo formation. The Ojo Alamo depth averages 2385 feet in the proposed Rosa tight gas area.

Most wells drilled in the Rosa area are drilled with natural mud to an average depth of 3700 feet. After intermediate casing is set the remainder of the well is drilled with natural gas. Neither the natural mud or the gas will contaminate any fresh water zones.

Normal casing designs in the Rosa area consist of 9-5/8ths or 10-3/4 inch OD surface casing, being set from the surface to an average depth of 3700 feet. Cementing of the intermediate casing includes enough cement to cover formations to a depth above the Ojo Alamo formation. The cement covers the Pictured Cliffs, Fruitland, and Kirtland formations, which are possible oil and gas bearing formations throughout the area.

The production casing is cemented from total depth to a depth above the Mesaverde formation, or to a point approximately 3000 feet above total depth. This cement covers the Dakota, Gallup, and Mesaverde, which are possible oil and gas bearing formations. A temperature survey is run after cementing the production casing to assure that all necessary zones were covered with cement. Therefor, all oil, gas, and water bearing formations in this area are isolated from each other by cement and casing.

The major water aquifer in this area, the Ojo Alamo formation, as well as the Pictured Cliffs, Fruitland, and Kirtland formations, is covered by cement and two strings of casing to protect them from the contamination with other formations.

Stimulation of the Dakota formation involves large fracture treatments, usually consisting of one or two percent potassium chloride water base that will not harm a fresh water aquifer.

Fresh water protection is adequate even with these large stimulation treatments due to zone isolation caused by cementation. The large distance of over 5500 feet between the Dakota formation and the Ojo Alamo fresh water aquifer is additional insurance that no wells exist that -- that no existing fresh water zones will be contaminated by the stimulation of Dakota wells in the area.

Therefor, New Mexico and Federal regulations will protect any fresh water supply that may be affected by drilling, completing, and producing the Dakota formation in the Rosa tight gas area.

Q Mr. McCord, is the price authorized by Section 107 of the Natural Gas Policy Act necessary to provide a reasonable incentive for production of natural gas from the subject formation due to the extraordinary risk for costs associated with such production?

A. Yes, it is.

Q. In your opinion is the data available to you and presented at this hearing supporting the conclusion that the entire area governed by this application qualifies for a tight formation designation under Section 107 of the Natural Gas Policy Act?

A. Yes, it does.

Q. At this time would you briefly summarize the conclusions you have reached in making a study of the subject area?

A. The estimated average in situ gas permeability throughout the Dakota pay section is expected to be 0.1 millidarcy or less for an average Dakota well depth of 7950 feet. The stabilized production rate at atmospheric pressure of these wells completed for production in the Dakota formation is not expected to exceed a maximum allowable rate of 336 Mcf of natural gas per day without stimulation. No well drilled into the Dakota formation in the Rosa area is expected to produce without stimulation more than 5 barrels of crude oil per day.

The proposed Rosa tight gas area meets

all the specifications required as stated above and should be designated a tight formation in the Basin Dakota Pool under Section 107 of the Natural Gas Policy Act of 1978.

Q Mr. McCord, has this area been approved for infill drilling?

A. Yes, it has in May of 1979.

Q And that was by Commission Order R-1670-V?

A. Yes, I believe so.

Q Have any infill wells been drilled in the subject area?

A. There have been a few infill wells drilled in this area after I have gathered all the data for this report. I'll point those out. They are both John Schalk wells. One would be in the southeast --

MR. STAMETS: Start out with the township and range.

A. Sure.

MR. STAMETS: It makes it a little easier to find.

A. Okay, 30, 30 North, 5 West, Section 2, southeast quarter.

The other well being in 30 North, 5 West, Section 12, I believe the northeast quarter.

These are recent wells that have been

drilled. My information or this map is May of 1981, so these are recent wells and it's my understanding have not been completed at this time.

Q How would you characterize the development of the subject area on the original 320-acre spacing?

A. Very, very sparse development under 320 acres. I believe I calculated under the existing acreage 53 producers. This is only 6 percent of our 320-acre spacing, and to my knowledge these two Schalk wells mentioned are the only two infill wells that have been attempted in the area. I believe that might have had something to do with that man's holdings in the area more than all the economic criteria involved.

Q Mr. McCord, in your opinion will further development of the subject area depend upon approval of this application and the resulting incentive price?

A. I think, yes, to be adequately developed this area will need the 107 price to make it economically feasible.

Q Will you please refer to and identify what has been marked as Applicant's Exhibit Eighteen?

A. Exhibit Eighteen is a written text explaining each of the exhibits I have just presented.

Q And this text was submitted with the

exhibits to the Commission and USGS?

A. Yes, that's correct.

Q. Were Exhibits One through Eighteen prepared by you or have you reviewed each of these exhibits and can you testify as to their accuracy?

A. Yes, I can. There were prepared by me.

Q. In your opinion will granting this application result in the production of gas that otherwise would not be produced?

A. Yes.

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

A. Yes, it will.

MR. CARR: At this time, Mr. Stamets, we would offer into evidence Applicant's Exhibits One through Eighteen.

MR. STAMETS: These exhibits will be admitted.

MR. CARR: Mr. Stamets, I've been asked to direct certain questions to Mr. McCord on behalf of the USGS and I'll be happy to do that now or at a later time, whenever you desire.

MR. STAMETS: Well, why don't you just

go ahead and do that now, Mr. Carr, and then we'll get that part out of the way.

Q Mr. McCord, what is the basis for the boundaries of the proposed tight gas sand area designation, and is this based on geologic and/or engineering parameters?

A. The area studied, and I'd like to point out is just an area of study, I'm not trying to say that areas outside are not tight gas areas, it was assigned to me by the Four Corners Gas Producers Association.

It is my feeling that it is not based on either geologic or engineering parameters, mainly on the rights of the Association.

Q Could you provide a structure Isopach insert map for the Dakota for the Rosa tight gas area?

A. It would be possible to supply a structure Isopach map, although I do not believe that this would show any more information than what cumulative production is shown on Figure Two. I believe this indicates that the well, the Rosa area is definitely not a very prolific area, and because of that I do not believe this information would be helpful, but if requested, we could supply this.

Q Now, Mr. McCord, the type log for the Rosa Unit No. 68 Well, which is used as your Exhibit Number Four, indicates that four separate zones were perforated for production. In reviewing the wells presented and the two cross sections, being Exhibits Number Five and Six, in some wells more than four zones were perforated.

The question is, is this application asking for all zones in the Dakota to be designated as a tight formation or only certain zones? And for the purposes of this question, zone refers to an individual sandstone separated by shale from other sandstones.

The question is, are you asking for all of the zones in the Dakota to be designated tight formations?

A. Yes. The Four Corners Gas Producers requested that the entire Dakota section as defined 400 feet below the base of the Greenhorn be designated as a tight formation.

Q Is this application asking for a tight sand designation for infill locations within the Rosa tight gas area, and there are certain examples given here. First, in Township 30 North, Range 5 West, Section 9, there are apparently two infill locations. Is it the request of the applicant that these be included in the tight sand designation?

A. Yes, it is.

Q There are also two locations in Section 10 and two in 20 of Township 30 North, Range 5 West.

A. Yes, those also.

Q. In Township --

MR. STAMETS: What was the last section?

MR. CARR: Section 20. All of this first group, they are all in Township 30 North, Range 5 West.

MR. STAMETS: And there are two in there or just one?

MR. CARR: Two, according to the question.

MR. STAMETS: Infill locations in Sections 9 and 20 --

MR. CARR: And 10.

MR. STAMETS: And 10. Let me get 10 marked on my exhibit, please.

MR. CARR: All right. Now in Township 31 North, Range 5 West, one location in Section 8.

A. Okay. I believe there should be two locations in Section 8. I do not have an infill well in that location, or in that section. I believe that should be two locations, and yes, we are asking for that also.

Q. And, again, two locations in Section 11 and in Section 17?

A. Yes.

Q. And now in Township 31 North, Range 6 West, two locations in Section 27 and two locations in Section 35.

A. Yes, we ask that these be part of the application as well.

MR. STAMETS: What was the second section, please?

MR. CARR: 35.

Q So you are asking that all infill locations within the Rosa area be included within the tight sand designation?

A. That is correct.

Q Mr. McCord, I direct your attention now to Exhibit Number Three, and it indicated that 12 Dakota wells were drilled in 1980, and 9 Dakota wells were drilled in 1981, all at current 103 prices.

Is it no longer economical to drill wells such as those drilled in 1980 and '81 under 103 prices?

A. Yes, it would still be economical to drill some of these newer wells that were drilled in 1980 and 1981 under 103 prices if there were -- existed any good producing characteristics such as exhibits by those wells. As to the current time there are not any of this type of location available. Therefor, to continue to drill wells in this area the 107 price would be necessary to -- to substantially complete the area.

Q Is it your answer that if there were

comparable locations in the Rosa area that the wells could be drilled at 103 prices?

A. Yes, it's my feeling they could.

Q. At this time, based on your study, you do not believe there are comparable locations?

A. I don't believe that, no.

Q. Is the 107 price necessary to have an economical well that would be similar in production potential to those drilled in 1980 and 1981?

A. Yes, it would be necessary because as we stated before there are no more wells of the calibre drilled of the ones in 1980 and '81 with -- with that calibre for 103 prices; therefor, the 107 is needed.

Also, there is no more drilling, the drilling plan for 1981 has been discontinued in this area because of the marginal economics.

Q. Mr. McCord, could you provide economic data as to the rate of return on -- showing comparison of several of the 21 wells that were drilled in 1980 and 1981, using the 103 price and contrasting that with the 107 price?

A. Yes, it is possible to provide this economic data, although in the instance of this area, there is mainly developed on 320 acres, acre spacing, and it's my understanding that economics are not required of 320-acre spacing in the Dakota.

Q Of the 21 wells that were drilled in 1980 and '81, do you know if the economics on these wells made them attractive prospects?

A Yes, in some of the wells they were attractive prospects under 103 prices, but it is my understanding that some of these wells drilled in '80 and '81 were demand wells. Also, some had marginal 103 economics. This is exemplified by the fact that the drilling in 1981 has been discontinued for the area because of the low profitability of these wells.

MR. CARR: I have no further questions of Mr. McCord.

MR. STAMETS: Are there other questions of the witness? Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q How many unspud Dakota locations or non-completed Dakota wells are there in this area at this time?

A Okay, Mr. Chavez, I have them marked on my map. Once again, the map is dated as of 5 of 81, so there have been some wells drilled since then.

In Township 31 North, Range 6 West, Section 8, Rosa No. 88, and that's in the south -- excuse me, the northwest quarter.

Q Has it been completed or just spud?

A. To my knowledge it's either -- I don't have the information as to -- at this time what stage of progress it's in. It has been staked and is a possible location for a future well. That's really the only thing I'm sure of. That's what I have marked on the map.

Also, in 31 North, 6 West, Section 14, in the northeast quarter, the Amoco Rosa 67. It's my understanding that this well is dry in the Dakota and Amoco is possibly going to recomplete in the Mesaverde or PC in this well.

All right, in 31 North, 5 West, Section 20, the northeast one quarter, the Rosa No. 85.

In that same township and range, Section 33, southwest quarter, the Rosa No. 77.

In 31 North, 4 West, Section 7, the northeast quarter, Mitchell, the Rosa No. 81.

In Section 9 of that same township, southwest quarter, the Rosa 82 by Mitchell.

Section 12, in the northwest quarter, the Amoco Rosa No. 87.

Section 15, northeast quarter, Mitchell Rosa No. 83.

Section 23, the northeast, Rosa No. 84. That's all for that township.

Q. These are staked but not completed wells?

A. The Mitchell wells I do know about. They have all been drilled. Only one well has been perforated and fraced and it is testing water at this time; no commercial gas production.

The other three wells have not been completed at this time.

All right, Township 30 North, 4 West, Section 13, Southland, the Simms Federal No. 1. That's the southeast quarter. This is drilled due to lease expiration date.

Okay, in 30 North, 5 West, I have the two Schalk infill locations, the 54-1E in Section 2, and the 57-1E in Section 12.

In Section 5, San Juan 30-5 Unit No. 79, in the northeast quarter.

Section 6, the southwest quarter, the 30-5 Unit No. 50.

Section 23, the southwest quarter, the 30-5 Unit No. 83.

Section 25, the 30-5 Unit No. 82 in the northwest quarter.

Q. Section what, I'm sorry?

A. 25. No. 82.

Q. What was that, I'm sorry?

A. That's the 30-5 Unit No. 82, the northwest quarter of 25, 30-5, okay?

Q. Okay.

A. Section 27, the southwest quarter, 30-5 Unit No. 81, and Section 36, the northeast quarter, the 30-5 Unit No. 77.

That is all the wells I have that are staked in this area as of this time.

Q. Is the drilling of these wells pending the outcome of this hearing? Or is it just pending rig availability?

A. I cannot tell you the actual answer to that. I don't know what the future plans on these wells, if any of them have been completed. I know some of them have been drilled but I would not be able to separate each one out. I've just picked them up through PI as possible locations in this area. I do not know the status of them all.

MR. CHAVEZ: That's all the questions I have.

MR. STAMETS: Are there other questions of the witness? Mr. Padilla?

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. McCord, you testified about comparable locations. What do you mean by a comparable location? Does that mean -- I think it would mean that that's a good location. Are you saying that in this area you've run out of good locations now?

A. Yes. In my talks with Phillips Petroleum Company, who is mostly in this 30-5 Unit, they have drilled most of these newer wells and from talking with these people, their feeling is that -- that all of their good drilling locations have been used up.

Q What have they based their justification for --

A. To tell you the truth, I couldn't answer that for you. That's just information they supplied to me.

Q And that's the same thing for the same calibre, same calibre, quote, same calibre of location, is that the same thing?

A. Yes. Yes.

Q Can you tell me what marginal economics are for drilling Dakota wells in this area?

A. Well, of course, Mr. Padilla, that's going to differ for any large company you're talking about, and if I said what marginal economics were, one company would call it good, one company would probably call it bad.

But I would say anything greater than a 3-year payout would be considered pretty marginal to be drilled. You just need a greater rate of return, greater return on your money than tying it up for that great period of time.

That's pretty rough, but once again, each company is going to have a different opinion of that same question.

Q Well, how much does it cost to drill one of these wells?

A. On information supplied by Amoco, approximately $800,000 to drill and complete these wells, and approximately 20 percent of that goes to the stimulation costs. So it's a considerable amount.

Q How much revenue would, say, a Section 103 price, can you get from a -- one of these wells located, say, in 30 North, 5 West? The newer wells.

A. Okay. I'd come up with an average ultimate production of .65 Bcf throughout the entire area. It's going to be, I would -- I would estimate that is a pretty good average for a 30-5 Unit. The actual dollars involved that that comes out to, I haven't calculated.

Q Wouldn't you have to apply the dollar

amount in order to determine whether or not you should get the incentive price?

A. To determine payout, yes. It's just a matter, I haven't -- I haven't plugged in that number to give an ultimate amount of money the wells will produce. That is how I determined a payout of approximately six years under 103 prices, taking an average decline and actual decline for the area, which is a rapid initial decline in the first year, leveling off through about year five at about a 10 percent decline rate. Using those numbers and a .65 Bcf, your payout to recover your $800,000 cost is approximately six years.

Q. Well, what's a 3-year payout? Is that on 107 prices?

A. No, a 3-year payout I mentioned to you, was my feeling, and this was only my feeling, of whether a well would be worth drilling or not.

A 6-year payout to me would be very marginal economics. You'ld be tying up your money a lot longer than need be there. You just -- you need better economics than that to be drilling these wells.

Q. This Exhibit Number Two doesn't show any wells at all in almost the entire east half of that area, except the well in the Section 34, 3 North, 3 West. That means that there have been no wells drilled with the exceptio of that one well that I mentioned on there.

A. No wells to the Dakota, that is -- that is correct. This would be an area that the 107 prices would virtually be a must for the exploration of. Obviously, no one has thought under 103 prices this area is worth prospecting. The 107 would -- would encourage drilling of wells in this area.

Q Is this -- is this area unitized currently under -- do you know?

A. I don't believe it's under a unit agreement, not the farther east. Most of the -- most of the newer wells are under existing units.

Q Is this east half area drilled in shallower formations?

A. It might possibly be but I don't have that information. I've just concentrated on Dakota wells. To my knowledge, if so, there would be very, very few wells.

Q You don't know whether there are any Pictured Cliffs wells, Pictured Cliff wells at all in this area?

A. Not offhand I don't. I would have to check, check my PI cards to see if any were drilled.

MR. PADILLA: I believe that's all I have, Mr. Examiner.

CROSS EXAMINATION

BY MR. STAMETS:

Q. Mr. McCord, in reviewing the exhibits, apparently you have based your contention that you would expect to find permeability throughout this area less than one-tenth of a millidarcy on a number of cores that were available in the area.

A. Yes, sir, that's correct.

Q. Okay. I looked at Exhibit Numbe. Two and identified eleven wells with potentials, I presume after stimulation, that exceeded 3-million cubic feet a day. I also noted that none of these wells happened to be a well that was cored. It seems as though the cored wells are always the poorer wells.

Is there any way of going backwards from what we have on these wells and determining the permeability?

A. Yes. The main thing being, first of all, I'd like to state that I'm sure you're aware that the initial potential is a very misleading figure on wells.

I have looked at approximately 20 wells throughout the area and have found that the first month's production from those wells is in the range of 15 to 20 percent of their IP, which indicates that their IP number is very misleading as what the wells will do against line pressure when put on line, actual production.

Also, I've found that the average first year production is approximately 16 percent.

So I'd like to state that the IP is a misleading number. Also, I see some of the wells you're talking about with over 3-million IP wells -- IP data, some of these are also wells that had initial natural production tests taken on them in a manner I described earlier, with the pitot tube test. With that test I found that averaging all these wells involved, found that all these wells still stayed under the 336 Mcf per day criteria, which associates approximately to a .1 millidarcy at reservoir conditions. Therefor, if they are below the 336, using Darcy's Law they would also be below the .1 millidarcy for the area.

That is about the only way I can come up with -- with an answer to your question are the natural production tests that were taken;in each case they were below the .1 millidarcy in situ.

Q. I believe you indicated, though, that the pitot tube tests were not noted for their accuracy.

A. That's -- that's correct, they are not. But in most instances I believe that they would be reporting rates too high, is my feeling. I think the actual production, the stabilized production rate, would be much lower than they report.

Q. There is, as Mr. Padilla pointed out, a dearth of evidence relative to Townships 30 and 31 North, Ranges 2 and 3 West, the only evidence being that no wells have been drilled.

On what could we base a finding that the permeability in the area is .1 of a millidarcy or less and productive capacity would be less than 366?

A. That would just have to be used from -- from the data we found already in the adjoining townships. It is a way away but there has also been no -- no active drilling in this area, which indicates that the area needs to be further developed, which the 107 price would -- would definitely encourage that.

In answer to your question, there is really no way to -- to tie that area in with the rest of -- with the rest of the -- the middle part of the area where the data is. The only point, without drilling wells in that area, it's just going to be tough.

MR. STAMETS: We're going to take about a fifteen minute recess while we have a little conference up here among the staff, at which time we will resume the hearing.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. McCord, after examining the information which has been submitted here today, it would appear to the Division staff that it will be necessary to continue this case for the presentation of economics data, which would demonstrate the wells in the area are not economic under the current 103 price.

And I would ask that this additional information be coordinated with Mr. Frank Chavez, who is our District Supervisor in Aztec, and also providing information to Mr. Padilla as to what is being done and the process that you intend to use to provide this data.

MR. CARR: We'll be glad to do that and after we meet with Mr. Chavez we will -- and agree on exactly what data is going to be required -- we'll notify all those who appeared in this case of what additional information has been requested.

MR. STAMETS: I'd also suggest that if there is any evidence which could be brought in that would help relative to 30 and 31 North, 2 and 3 West, that should be offered.

Is there anything -- any other questions of this witness? The witness may be excused.

I understood that there might someone here who would have trouble getting back and would like to make a statement.

MR. PAULSON: Yes, Mr. Examiner. Gary Paulson on behalf of Amoco Production Company.

We have come today in support of this application as a working interest owner in the area. It is our feeling that the added incentive price is required and necessary for future Basin Dakota development, and we would ask that the application be favorably considered by the Commission.

We do have evidence to present to the effect that a number of the wells that have been drilled in this area, in the Rosa Unit, were drilled upon demand by the USGS, and we had with respect to one year, 1980, evidence to present to the effect that the development plans submitted by the working interest owners for the Rosa Unit was to the effect that no wells were drilled and the USGS rejected that, and required -- or eventually a plan was submitted whereby three wells were drilled.

So at least some of the development activity in the area has been as a result of the USGS demand rather than a economic decision which was made by the working interest owners in the area.

And that will support the intent and we certainly have that evidence available in the event the Commission would like to consider it.

Thank you very much.

MR. STAMETS: Any other statements?

MR. PAID: Mr. Chairman, my name is Larry Pain. I'm an attorney with Phillips Petroleum Company.

Phillips Petroleum Company does support the application and urges that it be granted.

We are responsible for drilling of several of the wells that are listed in Exhibit Three that were drilled in 1980 and 1981, and you have requested additional economic information. We believe that any such information would show that some of the wells that were drilled were drilled with acceptable economics on the basis that they were within a small area that is somewhat more favorable than the remainder of the area covered by the application.

We feel that there are very few, if any, additional prospects of that character in the area covered by the application.

We are prepared to submit further evidence in that regard, if you would like for us to do so.

Phillips owns approximately 27,008 acres of oil and gas leases in the area covered by the application. Granting of the application would provide us with numerous additional drillable prospects over what we face now. What we face now is largely uneconomic prospects in the area.

We believe that the Commission should take a favorable attitude toward the granting of applications for tight formations where the criteria are reasonably satisfied. Common sense tells us that the price limits established under the Natural Gas Policy Act of 1978 are considerably lower than the BTU equivalent of oil prices and that the pricing assumptions that were used by Congress;to-wit, oil equivalency as of the time of enactment of the NGPA was an assumption that worldwide prices would not rise any faster than the rate of inflation, has been completely shattered by events which have occurred since the enactment of the NGPA. With world oil selling at well in excess of $30.00 per barrel, and an assumption of a 5.8 BTU equivalency factor, any gas that can be developed at any cost less than approximately $6.00 per Mcf can and should be developed in order to enhance our domestic supply situation and reduce our dependency on imports.

The Section 107 pricing authority under the NGPA is an appropriate method for stimulating additional domestic gas sources, which should be viewed favorably by this Commission and also by the FERC as it reviews your recommendations.

Thank you very much.

MR. STAMETS: Are there any other statements at this time?

Go off the record a second.

(Thereupon discussion was had off the record.)

Is there anything further in this case today?

This case, then, will be continued to the August 26th Examiner Hearing.

(Hearing concluded.)

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CERTIFICATE

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

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

EXAMINER HEARING

IN THE MATTER OF:

Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan County, New Mexico, and Rio Arriba County, New Mexico. CASE 7317

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO.

Case 7312

APPLICATION

Comes now FOUR CORNERS GAS PRODUCERS ASSOCIATION, by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Dakota formation (Basin Dakota Field) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

1. Applicant is the owner and operator of certain interests in the Dakota formation (Basin Dakota Field) underlying the following described lands situated in San Juan and Rio Arriba Counties, New Mexico:

<u>Township 30 North, Range 2 West, N.M.P.M.</u>
Sections 1 through 36: All

<u>Township 30 North, Range 3 West, N.M.P.M.</u>
Sections 1 through 36: All

<u>Township 30 North, Range 4 West, N.M.P.M.</u>
Sections 1 through 36: All

<u>Township 30 North, Range 5 West, N.M.P.M.</u>
Sections 1 through 36: All

Township 30 North, Range 6 West, N.M.P.M.
Sections 1 through 36: All

Township 30 North, Range 7 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 2 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 3 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 4 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 5 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 6 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 7 West, N.M.P.M.
Sections 1 through 36: All

Containing a total of 270,260 acres, more or less.

2. The Dakota formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7950 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 336 mcf of gas per day.

4. No well drilled into the Dakota formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning

and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705 that the Dakota formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By [signature]

William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been mailed to the United States Geological Survey, postage prepaid, at Post Office Box 26124, Albuquerque, New Mexico, 87125, on this 9th day of July, 1981.

[signature]

William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

RECEIVED
JUL 09 1981
OIL CONSERVATION DIVISION
SANTA FE

IN THE MATTER OF THE APPLICATION
OF FOUR CORNERS GAS PRODUCERS
ASSOCIATION FOR DESIGNATION OF
TIGHT FORMATION, SAN JUAN AND
RIO ARRIBA COUNTIES, NEW MEXICO.

Case 7317

APPLICATION

Comes now FOUR CORNERS GAS PRODUCERS ASSOCIATION, by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Dakota formation (Basin Dakota Field) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

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Sections 1 through 36: All

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Sections 1 through 36: All

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Sections 1 through 36: All

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Sections 1 through 36: All

Township 30 North, Range 7 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 2 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 3 West, N.M.P.M.
Sections 1 through 36: All

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Sections 1 through 36: All

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Township 31 North, Range 6 West, N.M.P.M.
Sections 1 through 36: All

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Sections 1 through 36: All

Containing a total of 270,260 acres, more or less.

2. The Dakota formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7950 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 336 mcf of gas per day.

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and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705 that the Dakota formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By [signature]
William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

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[signature]
William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF FOUR CORNERS GAS PRODUCERS
ASSOCIATION FOR DESIGNATION OF
TIGHT FORMATION, SAN JUAN AND
RIO ARRIBA COUNTIES, NEW MEXICO.

Case 7317

APPLICATION

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Sections 1 through 36: All

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Sections 1 through 36: All

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Sections 1 through 36: All

Township 30 North, Range 6 West, N.M.P.M.
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Sections 1 through 36: All

Township 31 North, Range 2 West, N.M.P.M.
Sections 1 through 36: All

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Sections 1 through 36: All

Township 31 North, Range 4 West, N.M.P.M.
Sections 1 through 36: All

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Containing a total of 270,260 acres, more or less.

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Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By [signature]
William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been mailed to the United States Geological Survey, postage prepaid, at Post Office Box 26124, Albuquerque, New Mexico, 87125, on this 9th day of July, 1981.

[signature]
William F. Carr

Memo

From

PRENTISS CHILDS
Planner

To

[illegible]

[illegible]

~~[illegible]~~ reserves recoverable

income @ both rates

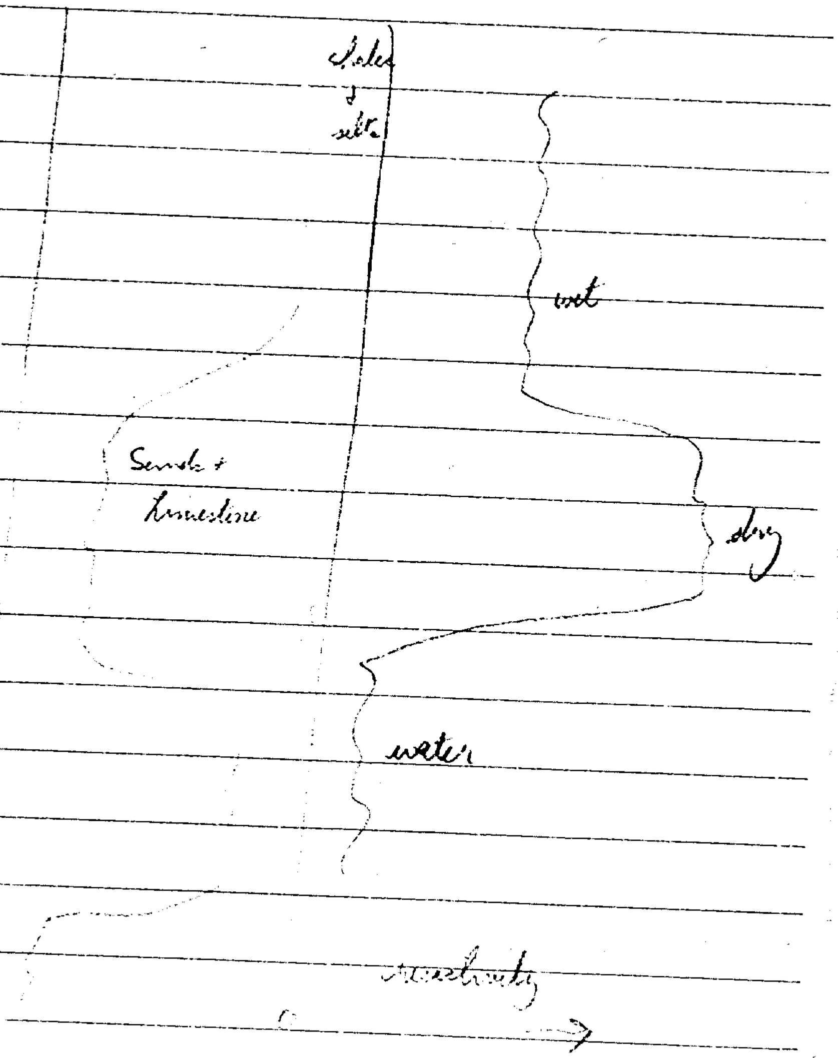
– taxes

should would like a 15% profit

Oil Conservation   Santa Fe, New Mexico

KILSBY TUBESUPPLY
DENVER: (303) 371-7600
COLORADO: (800) 332-1194
OTHER STATES: (800) 525-1820

SP - Gamma Ray



CARBON STEEL • STAINLESS STEEL • ALLOY • ALUMINUM

Case # 7317   August 26, 1981

Kevin H. McLeod w/ Four Corners Gas Producers Association

Pg. 4 — Exhibit A - electric log showing tops of formations, the Greenhorn, Graneros, & Dakota, are shown, Dakota @ 2300' of E.L. Potest Monero Dome #1 (30N - 1W - 24) approx. 6 mi. East (is off map)
— Avg. is 7950' for the Rosa tight gas area. due to steep upward trend of the form.

Pg. 5 — Exhibit B - core data from Rodney DeVilliers #31 1 W. Quarilla located 4 mi. south 21, 29N, 3W.
page 1 - summary of core analysis → lab perm = 0.018 md → 0.10
2 - actual core analysis results →

—

Case # 7317 August 26, 1981 Examiner Hearing

Kevin H. McCord

Four Corners Gas Producers Association

4 I. Exhibit A: Electric log showing formation tops E.L. Potal Mesa Dome #1 (30N-1W-

A. Greenhorn

B. Graneros appr. 6 mi. east of

C. Dakota @ 2300'

5 II. Exhibit B: Core data from Rodney DeVilliers #31-1W Jicarilla located 4 mi. south in 21, 29N, 3W.

A. Page one: summary of core analysis

1. Lab perm. = 0.018 md.

2. Applying a 10% factor (which was considered for the rest of the Rosa Unit), 0.002 md. in situ perm.

3. estimated 15 to 20 MCF of gas per day from DST.

4. Darcy's law presented previously results in a 9 MCF per day flow rate.

B. Page two: actual core analysis results

6 III. Cased hole DST by PanAm Corp. on Jicarilla #1 Payosa located 3 mi. North in 23-32N-3W. Was unable to come up w/ any reliable perm. info., also turned out to be a dry hole.

7 IV. Southland Royalty Sims Fed. #1 13, 30N, 4W is at present drilling and will submit DST results when data is available.

V. Sunray DX Jicarilla Tribal #1 - dry hole.

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
WILLIAM G. WARDLE
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TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

November 24, 1981

Mr. R. L. Stamets
Technical Support Chief
Oil Conservation Division
Post Office Box 2088
Santa Fe, New Mexico 87501

RECEIVED
NOV 24 1981
OIL CONSERVATION DIVISION
SANTA FE

Re: Case 7317: Application of Four Corners Gas Producers Association for Designation of a Tight Formation, San Juan and Rio Arriba Counties, New Mexico

Dear Mr. Stamets:

Enclosed is a proposed order of the Division in the above-referenced matter.

If we may be of any further assistance to you in this case, please advise.

Very truly yours,

William F. Carr

William F. Carr

WFC:lr

Enclosure

cc: Mr. Kevin McCord

E
VU AGT SANA

AYA105(1254)(1-013427M237)PD 08/25/81 1247
TLX ARCO TLX A DAL
ZCZC 01 PD DALLAS, TEXAS 8-25-81

PMS THE DEPARTMENT OF ENERGY & MINERALS ATTN: THE MEMBERS OF

THE NEW MEXICO OIL AND GAS CONSERVATION DIVISION

P.O. BOX 2088

SANTA FE, NEW MEXICO 87501

RE: CASE NO. 7317

APPLICATION OF FOUR CORNERS GAS PRODUCERS

ASSOCIATION FOR DESIGNATION OF THE ROSA AREA OF

THE BASIN DAKOTA FIELD AS A TIGHT GAS FORMATION

ARCO OIL AND GAS COMPANY, A DIVISION OF ATLANTIC RICHFIELD COMPANY (ARCO), IS THE OWNER OF A NUMBER OF LEASES IN THE PROPOSED ROSA TIGHT GAS AREA IN NORTHWESTERN NEW MEXICO. ARCO HAS REVIEWED THE APPLICATION OF THE FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR TIGHT FORMATION DESIGNATION OF THIS AREA AND FULLY SUPPORTS SAID

APPLICATION. ARCO URGES THE COMMISSION TO APPROVE THE APPLICATION OF FOUR CORNERS AND TO MAKE RECOMMENDATION TO THE FEDERAL ENERGY REGULATORY COMMISSION THAT THE ROSA AREA OF THE BASIN DAKOTA FIELD BE DESIGNATED AS A TIGHT GAS FORMATION.

PAUL T. DAVIS

ARCO OIL AND GAS COMPANY

P.O. BOX 2819
DALLAS, TEXAS 75221
NNNN

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
WILLIAM G. WARDLE

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TELECOPIER: (505) 983-6043

July 9, 1981

RECEIVED
JUL 09 1981
OIL CONSERVATION DIVISION
SANTA FE

Mr. Joe D. Ramey
Division Director
Oil Conservation Division
New Mexico Department of
Energy and Minerals
Post Office Box 2088
Santa Fe, New Mexico 87501

Case 7317

Re: Application of Four Corners Gas Producers Association for Designation of a Tight Formation, San Juan and Rio Arriba Counties, New Mexico

Dear Mr. Ramey:

Enclosed in triplicate is the application of Four Corners Gas Producers Association in the above-referenced matter.

The applicant requests that this matter be included on the docket for the examiner hearing scheduled to be held on July 29, 1981.

Very truly yours,

William F. Carr

William F. Carr

WFC:lr

Enclosures

CASE 7335: Application of C & E Operators, Inc. for amendment to Division Order No. R-5459, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of Division Order No. R-5459 by amending the location of the Northwest-Southeast trending line as described in Exhibit A of said Order No. R-5459 pertaining to Township 30 North, Range 11 West, as follows: Section 6: West and South; Section 8: West and South; Sections 9, 10, and 11: South; and Section 13: West and South.

CASE 7336: Application of C & E Operators, Inc. for three triple completions, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks authority to triply complete the following wells in Township 30 North, Range 11 West, to produce gas from the Farmer-Fruitland Pool, the Aztec-Pictured Cliffs Pool, and the Blanco Mesaverde Pool through separate strings of tubing: Aztec Wells Nos. 8 in Unit N of Section 8 and 9 in Unit M of Section 9; and Fee Well No. 8 in Unit C of Section 8.

CASE 7337: Application of Beartooth Oil & Gas Company for downhole commingling, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of Ojito Gallup-Dakota and Blanco Mesaverde production in the wellbore of its Minel Federal Well No. 1 located in Unit E of Section 7, Township 25 North, Range 3 West. Applicant further seeks the establishment of an administrative procedure for approval of downhole commingling of Gallup-Dakota and Mesaverde production in the W/2 of Sections 6 and 7, Township 25 North, Range 3 West.

CASE 7338: Application of Beartooth Oil & Gas Company for downhole commingling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of Fruitland and Farmington production in the wellbore of its Elledge Federal 34 Well No. 11 located in Unit D of Section 34, Township 29 North, Range 11 West.

CASE 7339: Application of Doyle Hartman for compulsory pooling, unorthodox well location, and simultaneous dedication, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Jalmat Pool underlying the S/2 of Section 17, Township 24 South, Range 37 East, to be simultaneously dedicated to his Late Thomas Well No. 1 located in Unit M of said Section 17, and to two proposed wells, one to be drilled at an orthodox location in Unit J and the other at an unorthodox location 2310 feet from the South line and 330 feet from the West line, both in said Section 17. Also to be considered will be the cost of drilling and completing said wells and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the wells, and a charge for risk involved in drilling said wells.

CASE 7340: Application of Doyle Hartman for directional drilling and unorthodox location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to directionally drill his City of Jal Well No. 1, the surface location of which is 1635 feet from the South line and 1210 feet from the West line of Section 20, Township 25 South, Range 37 East, Jalmat Pool, to top the Jalmat at a bottom hole location 660 feet from the South and West Lines at a vertical depth of 2800 feet and to bottom said well at an unorthodox location 330 feet from the South and West lines at a vertical depth of 3500 feet.

CASE 7317: (Continued from July 29, 1981, Examiner Hearing)

Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying Townships 30 and 31 North, Ranges 2 thru 7 West, containing 270,260 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 7129: (Continued from August 12, 1981, Examiner Hearing)

Application of Koch Exploration Company for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Dakota formation underlying the N/2 of Section 28, Township 28 North, Range 8 West, 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 7169: (Continued from August 12, 1981, Examiner Hearing)

Application of Koch Exploration Company for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Dakota formation underlying the S/2 of Section 22, Township 28 North, Range 8 West, 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 7315: Application of Rhema Oil Processing for an oil treating plant permit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority for the construction and operation of an oil treating plant for the purpose of treating and reclaiming sediment oil at a site in the NW/4 of Section 30, Township 18 South, Range 38 East.

CASE 7274: (Continued from June 17, 1981, Examiner Hearing)

Application of Bass Enterprises Production Company for directional drilling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks authority to directionally drill its James Ranch Unit Well No. 13 from an unorthodox surface location 660 feet from the South line and 1340 feet from the East line of Section 36, Township 22 South, Range 30 East, in such a manner as to bottom said well in the Morrow formation at a standard location at least 660 feet from the South line and 1980 feet from the West line of Section 31, Township 22 South, Range 31 East, the S/2 of said Section 31 to be dedicated to the well.

CASE 7303: (Continued from July 15, 1981, Examiner Hearing)

Application of Florida Hydrocarbons Company for surface commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the surface commingling of Morrow, Strawn, Atoka, and Wolfcamp gas produced from five wells located in Unit F of Section 10, Units G and O of Section 15, and Units A and I of Section 22, all in Township 23 South, Range 34 East, Antelope Ridge Field, after separately metering the gas produced from each well and each zone. Lease liquids would be separated out at the wellhead and the gas processed in a plant, allocating plant production back to each well on the basis of meter readings. Applicant further seeks a procedure whereby additional wells could be similarly commingled in said system.

CASE 7316: Application of Blackwood & Nichols Company, Ltd. for amendment of Order No. R-6636, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of Division Order No. R-6636 which authorized directional drilling for its Northeast Blanco Unit Well No. 32-A in Section 7, Township 30 North, Range 7 West, to provide for an amended bottom hole location 2213 feet from the South line and 815 feet from the East line of said Section 7.

CASE 7317: Application of Four Corners Gas Producers Association for designation of a tight formation, San Juan and Rio Arriba Counties, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying Townships 30 and 31 North, Ranges 2 thru 7 West, containing 270,260 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 7318: Application of Phillips Petroleum Company for salt water disposal, Roosevelt County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Wolfcamp formation in the interval from 7332 feet to 7341 feet in its Peterson "B" Well No. 1 in Unit M of Section 29, Township 5 South, Range 33 East, South Peterson Field.

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. 7317
Order No. R-6883

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on July 29, and August 26, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets.

NOW, on this _____ day of ~~November,~~ 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 Four Corners Gas Producers Association 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 Dakota formation underlying the following lands situated in San Juan and Rio Arriba Counties, New Mexico, hereinafter referred to as the Dakota formation, be designated as a tight formation in said Federal Energy Regulatory Commission's regulations:

TOWNSHIP 30 NORTH, RANGE 2 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 3 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 4 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 7 WEST, NMPM
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TOWNSHIP 31 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

Containing a total of 270,260 acres, more or less.

(3) That the area proposed for tight formation designation lies within the horizontal limits of the Basin Dakota Gas Pool, which is a very large area previously defined and described by the Oil Conservation Division in San Juan and Rio Arriba Counties.

(4) from next page

(5) ~~(4)~~ That within the Basin Dakota Gas Pool are large areas of extensive development and large areas of very limited development.

(6) ~~(5)~~ That the 320-acre area for which a tight formation designation is sought is one of very limited development being comprised of approximately 432 proration units of which 66 are developed by one well and two by one well plus an infill well.

(7) ~~(6)~~ That the area proposed for tight formation designation is a largely undeveloped exploratory area.

(8) That the Dakota formation underlies all the above described lands; that the upper Dakota sand consists of barrier beach deposits about 40 to 60 feet thick, composed of fine grained, quartz-rich sandstones characterized by an increase in grain size upward and low angle crossbedding. The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones and sandstones. The basal Dakota consists of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstone. ~~Counties, New Mexico.~~

(9) ~~(8)~~ That the top of the Dakota formation is found at an average depth of 7950 feet below the surface of the area set out in Finding No. (2) above; and has approximately 250 feet of gross thickness.

(10) ~~(9)~~ That the type section for the Dakota formation for the proposed tight formation designation is found at a depth of from approximately 7852 feet to 8084 feet on the log from the Northwest Pipeline Corporation Rosa Unit No. 68 Well located in Unit L of Section 17, Township 31 North, Range 5 West, Rio Arriba County, New Mexico.

(10) That the technical evidence presented in this case demonstrated that the predominant percentage of wells which may be completed in the Dakota formation within the proposed tight formation area may reasonably be presumed to exhibit permeability, gas productivity, or crude oil productivity not 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.

(12) That within the proposed area there is a recognized aquifer being the Ojo Alamo, found at an average depth of 2385 feet or approximately 5565 feet above the Dakota formation.

(13) That existing State of New Mexico and Federal Regulations relating to casing and cementing of wells will assure that development of the Dakota formation will not adversely affect any overlying aquifers.

Previous page (4) ~~(13)~~ That the Dakota formation has been approved for infill drilling which permits the subject area to be developed with one Dakota well on each quarter section or 160 acre tract.

(14) That in the instant case the Division accepted evidence on economics within this area.

(15) That the economic data was highly variable and of no value in reaching a decision relative to this area.

(16) That based on technical data alone the area described on Exhibit "A" to this order 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 Dakota formation underlying those lands in San Juan and Rio Arriba Counties, New Mexico, described on Exhibit "A" to this order, be designated as a tight formation.

(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

S E A L

EXHIBIT A

TOWNSHIP 30 NORTH, RANGE 2 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 3 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 4 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 2 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 3 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 4 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

CASE NO. 7317
Order No. R-6883-A

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO.

NUNC PRO TUNC ORDER

BY THE DIVISION:

It appearing to the Division that Order No. R-6883 dated January 11, 1982, does not correctly state the intended order of the Division,

IT IS THEREFORE ORDERED:

(1) That Finding No. (6) on pages 2 and 3 of Order No. R-6883 is hereby corrected to read in its entirety as follows:

"(6) That the area for which a tight formation designation is sought is one of very limited development being comprised of approximately 846 proration units of which 66 are developed by one well and two by one well plus an infill well."

(2) That the corrections set forth in this order be entered *nunc pro tunc* as of January 11, 1982.

DONE at Santa Fe, New Mexico, on this ________ day of April, 1982.

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. 7317
Order No. R-6883

APPLICATION OF FOUR CORNERS GAS PRODUCERS ASSOCIATION FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN AND RIO ARRIBA COUNTIES, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on July 29 and August 26, 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, Four Corners Gas Producers Association, 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 Dakota formation underlying the following lands situated in San Juan and Rio Arriba Counties, New Mexico, hereinafter referred to as the Dakota formation, be designated as a tight formation in said Federal Energy Regulatory Commission's regulations:

TOWNSHIP 30 NORTH, RANGE 2 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 3 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 4 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 30 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 2 WEST, NMPM
Sections 1 through 36: All

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Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 4 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 5 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

Containing a total of 270,260 acres, more or less.

(3) That the area proposed for tight formation designation lies within the horizontal limits of the Basin-Dakota Gas Pool, which is a very large area previously defined and described by the Oil Conservation Division in San Juan and Rio Arriba Counties.

(4) That the Dakota formation has been approved for infill drilling which permits the subject area to be developed with one Dakota well on each quarter section or 160-acre tract.

(5) That within the Basin-Dakota Gas Pool are large areas of extensive development and large areas of very limited development.

(6) That the area for which a tight formation designation is sought is one of very limited development being comprised of

approximately 432 320-acre proration units of which 66 are developed by one well and two by one well plus an infill well.

(7) That the area proposed for tight formation designation is a largely undeveloped exploratory area.

(8) That the Dakota formation underlies all of the above described lands; that the upper Dakota sand consists of barrier beach deposits about 40 to 60 feet thick, composed of fine grained, quartz-rich sandstones characterized by an increase in grain size upward and low angle crossbedding. The next highest unit is transitional between fluvial and marine sedimentation containing dark carbonaceous shales, thin mudstones, siltstones and sandstones. The basal Dakota consists of carbonaceous shales, thin coal seams, siltstones, and thin channel sandstone.

(9) That the top of the Dakota formation is found at an average depth of 7950 feet below the surface of the area set out in Finding No. (2) above, and has approximately 250 feet of gross thickness.

(10) That the type section for the Dakota formation for the proposed tight formation designation is found at a depth of from approximately 7852 feet to 8084 feet on the log from the Northwest Pipeline Corporation Rosa Unit Well No. 68 located in Unit L of Section 17, Township 31 North, Range 5 West, Rio Arriba County, New Mexico.

(11) That the technical evidence presented in this case demonstrated that the predominant percentage of wells which may be completed in the Dakota formation within the proposed tight formation area may reasonably be presumed to exhibit permeability, gas productivity, or crude oil productivity not 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.

(12) That within the proposed area there is a recognized aquifer being the Ojo Alamo, found at an average depth of 2385 feet or approximately 5565 feet above the Dakota formation.

(13) That existing State of New Mexico and Federal Regulations relating to casing and cementing of wells will assure that development of the Dakota formation will not adversely affect any overlying aquifers.

(14) That in the instant case the Division accepted evidence on economics within this area.

(15) That the economic data was highly variable and of no value in reaching a decision relative to this area.

(16) That based on technical data alone the area described on Exhibit "A" to this order 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 Dakota formation underlying those lands in San Juan and Rio Arriba Counties, New Mexico, described on Exhibit "A" to this order, be designated as a tight formation.

(2) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY
Director

S E A L
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Sections 1 through 36: All

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TOWNSHIP 31 NORTH, RANGE 6 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 7 WEST, NMPM
Sections 1 through 36: All

Exhibit A
Order No. R-6883