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

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Case 110.

Application
Transcripts

Small Exhibits

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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. T3lN-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 (!) 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

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CASE NO. 73.73

Submitted by Helous

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 abandoneá 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 Pasin 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. Powever, 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 Gepth 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

POST OFFICE BOX 2088 STATE LAND OFFICE BUILDING SANTA FF, NEW MEXICO 87501 I505I 827-2434

January 12, 1982

Mr. William F. Carr	Re:	CASE NO. 7317 ORDER NO.R-6883
Campbell, Byrd & Black Attorneys at Law		\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\
Post Office Box 2208 Santa Fe, New Mexico		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.

Ypurs very truly, JOE D. RAMEY Director

JDR/fd

Copy of order also sent to:

Hobbs OCD Artesia OCD Aztec OCD

Other Tom Kellahin, Gary Paulse, 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 DESIG-NATION 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 ONL CONSERVATION DIVISION

DOE D. RAMEY

S E A L fd/



STATE OF NEW MEXICO ENERGY AND MINERALS DEPARTMENT OIL CONSERVATION DIVISION

BRUCE KING GOVERNOR LARRY KEHOE SECRETARY

April 19, 1982

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

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

Re: Tight Formation 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 April 15, 1982

POST OFFICE BOX 2088 61.TE LAND OFFICE BUILDING SANTA FE, NEW MEXICO 87501 (505) 827-2434

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

Re: Tight Formation Designations

Dear Mr. Kilchrist:

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

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

If we can be of further assistance, please advise.

Sincerely,

W. PERRY PEARCE General Counsel

WPP/dr enc.



United States Department of the Interior

OFFICE OF THE SECRETARY
Minerals Management Service
South Central Region
P. 0. Box 26124
Albuquerque, New Mexico 873

EB 0 \$ 1982

Mr. W. Perry Pearce Oil Conservation Division State of New Mexico P. 0. 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,

Gene F. Daniel Deputy Minerals Manager

Oil and Gas

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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 CASE
of a tight formation, San Juan and Rio 7317
Arriba Counties, New Mexico.

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

APPEARANCES

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

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

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MR. PEARCE: Application of Four Corners

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Gas Producers Association for designation of a tight formation,

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San Juan and Rio Arriba Counties, New Mexico.

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MR. CARR: May it please the Examiner,

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my name is William F. Carr, with the law firm Campbell, Byrd,

& Black, Santa Fe, appearing on behalf of the applicant.

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This is a continuation of Case 7317 and

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I would request that the record show that Kevin McCord, who

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testified in the previous case, is qualified and that he is

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MR. STAMETS: The record will so show.

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KEVIN H. McCORD

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

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DIRECT EXAMINATION

BY MR. CARR:

under oath in this matter.

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

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Yes, I have.

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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.

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

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two ways of estimating natural flow.

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

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.

Does Southland Royalty Company also have plans in the area?

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.

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?

Yes, sir, they are. MR. STAMETS: Did any of these wells make any attempts to determine pre-frac flow? 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. 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? 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.

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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.

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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 of 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.

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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.

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.

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.

BPU 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.

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. McCorā, were Exhibits A through E compiled under your direction?

2 Yes, all but Exhibit D, which was, as I 3 stated, presented to me by Mitchell Energy Corp. And your -- does your review of these exhibits indicate that they are correct and accurately portray the data you are attempting to show? Yes, they do. MR. CARR: At this time, Mr. Stamets, we 9 would offer Exhibits A through E. 10 MR. STAMETS: These exhibits will be 11 admitted. 12 MR. CARR: I have nothing further of Mr. 13 McCord on direct. 14 15 CROSS EXAMINATION 16 MY MR. STAMETS: 17 Mr. McCord, Exhibit E, the last page of Q. 18 your economic exhibit. 19 Yes, sir. 20 In Case No. 1 you're looking at what 21 you consider to be the lowest possible well cost in the area? 22 That is correct. 23 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.

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?

Not from the figures I have here. These were the numbers supplied to me by Amoco. I don't have their

2 printout. This was information that they considered confi-3 dential and did not want to present unless we -- we absolutely had to. We can confer from that DROI 15 number 6 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? 10 MR. CHAVEZ: Yes, sir. 11 12 QUESTIONS BY MR. CHAVEZ: 13 Mr. McCord, in a discounted rate of re-14 turn what does the absolute number zero indicate? Does that 15 indicate a break even point? 16 Yes, it does. 17 At 15 percent. 18 That's right. That would mean that 19 your money is worth -- all that is doing is taking your future 20 monies and bringing it to the present. 21 Okay. The average depth for the Dakota 22 in these townships, how did you arrive at that again? 23 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.

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,

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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:

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.

\$820,000, or more indicative cost, that's -- that's not economic, no.

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.

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?

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

1 2 there are dry holes in the area. Q. economical wells? 10 11 12 real cheap. 13 14 16 17 18 19 20 21 22 23 24 25

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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.

How does Northwest Pipeline drill such

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

Does Amoco management know about the engineering of Northwest Pipeline?

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 quess 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?

a 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.

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.

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.

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?

It wouldn't take but one, probably. One in four, one in five, one is three,

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?

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?

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.

tions of this witness? Mr. Kendrick, back in the hall, we'll give you a turn.

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QUESTIONS BY MR. KENDRICK:

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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.

MR. STAMETS: Are there any other ques-

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.

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?

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?

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32 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 11 application, and that ARCO would urge the Commission to ap-12 prove of this application. 13 MR. STAMETS: All right, we appreciate 14 that. If there are no further questions, Mr. 16 McCord may be excused. 17 Are there any other statements? 18 With the provision for the other inform-19 ation that we've discussed here, the case will be taken under 20 advisement. 21 22 (Hearing concluded.) 23 24 25

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREPY 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.

Story 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

Oil Conservation Division

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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	Rcзa 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 develop- ment in a west-east direction.
6	Cross Section B-B'	Show Dakota formation develop- ment 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

CASE NO. 7313

ROSA TIGHT GAS AREA WELLS

	CLORE SC.			•			
COMPANY S. S.	100 A	LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
F. 10	77 1						
Sunray DX Oil Co.	#1 Jicarilla Tribal	NW/NW 34 30-3	8213	09/54	D&A	1	-
El Paso Natural Gas Co.	Carson ₩2	NW/SW 7 30-4	8083	09/79	869/0	302/0	.055/0
El Paso Natural Cas Co.	39 San Juan 30-4 Unit	SE/NW 18 30-4	8425	02/81	2506/0	New Well	400
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	1
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 Can Juan 30-5 Unit	NW/NE 10 30-5	7919	03/81	2635/0	New Well	1
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

	WELL NA San Juan 30-5 San Juan 30-5 San Juan 30-5 San Juan 30-5	LOCATION SW/NE 18 30-5 SW/SW 19 30-5 NW/NE 20 30-5 SW/SW 20 30-5	DAKOTA DEFTH 7667 7607 7790 7646	IP DATE 06/30 06/30 03/56 01/30 12/59	IP GAS/OIL MCFFD/BOPD 2035/0 P&A 3691/0 1309/0	1980 PROD. MCFPD/BOPD New Well 24/0 New Well	CUMULATIVE 01-01-81 ECF/BO
Northwest Pipeline Corp.	San Juan 30-5	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	
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	
Blackwood & Nichols	12 NE Blanco Unit	SY /NE 18 30-7	7590	06/60	P&A Dakota (MV Compl.)		
Northwest Pipeline Corp.	Rosa Unit #42	SW/NF 19 31-4	not given	11/62	$\mathbf{D} \boldsymbol{\ell} \cdot \mathbf{A}$	-	
Northwest Pipeline Corp.	Rosa Unit #43	NW/SE 19 31-4	8158	05/62	2352/0	98/0	
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	
Coastline Petroleum	1 Schalk-58	NE/SW 2 31-5	7856	08/73	D&A	ļ	
Northwest Pipeline Corp.	Rosa Unit #53	NW/NE 8 31-5	7900	03/70	1043/0	126/0	
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.	CUMULATIVE 01-01-81 BCF/B0
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	1.2/62	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)		1
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	1	ļ
Northwest Pipeline Corp.	79 San Juan 31-6 Unit	NE/SW 22 31-6	7757	03/81	1858/3	New Well	}

A IP DATE 01/70 03/812/73		IP GAS/OIL MCFPD/BOPD 1385/0 2557/0 1341/0 1783/0	COMPANY WELL NAME LOCATION DEPTH IP DATE	Northwest Pipeline Corp. Rosa Unit #51 NE/NW 23 31-6 7823 01/70	Northwest Pipeline Corp. 36 San Juan 31-6 Unit NE/NE 27 31-6 7806 03/81	Northwest Pipeline Corp. 24 San Juan 31-6 Unit NE/SW 27 31-6 7939 :2/73	Northwest Pipeline Corp. 16 San Juan 31-6 Unit SE/SW 33 31-6 7895 07/59	Northwest Pipeline Corp. 33 San Juan 31-6 Unit SW/NE 34 31-6 8712 06/80	Northwest Pipeline Corp. 35 San Juan 31-6 Unit NE/NE 35 31-6 7908 07/80	Northwest Pipeline Corp. 31 San Juan 31-6 Unit SE/SE 35 31-6 7796 C6/80	Northwest Pipeline Corp. 37 San Juan 31-6 Unit SW/SE 36 31-6 7952 C4/-1	Blackwood & Nichols 58 NE Blanco Unit NE/NE 13 31-7 7975 11/59	Blackwood & Nichols 57 NE Blanco Unit NE/NE 21 31-7 7780 09/59		Blackwood & Nichols 55 NE Blanco Unit NW/NE 22 31-7 7856 10/58	& Nichols	& Nichols
	DAKOTA DEPTH 7823 7806 7939	DAKOTA IP DATE 7823 01/70 7806 03/81 7939 ::2/73			Unit					. •			Unit Unit Unit Unit	Unit Unit Unit	Unit Unit Unit Unit	Unit Unit Unit Unit	Unit Unit Unit
		IP DATE 01/70 03/81 :2/73	ξ.	•	31-6					34 31-6	34 31-6 35 31-6 35 31-6	34 31-6 35 31-6 35 31-6	34 31-6 35 31-6 35 31-6 36 31-6 13 31-7	34 31-6 35 31-6 35 31-6 36 31-6 13 31-7 21 31-7	34 31-6 35 31-6 35 31-6 36 31-6 13 31-7 21 31-7 22 31-7	34 31-6 35 31-6 35 31-6 36 31-6 13 31-7 21 31-7 22 31-7	34 31-6 35 31-6 35 31-6 36 31-7 13 31-7 21 31-7 22 31-7 27 31-7 28 31-7
IP GAS/OIL 1980 PROD. MCFPD/BOPD MCFPD/BOPD 1385/0 170/0 2557/0 New Well 1341/0 SI	1980 PROD. MCFPD/BOPD 170/0 New Well SI	J	O PROD. PD/BOPD	0/0													

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

•	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	
7653-7654		0.01
	1	0.02
7654-7655	1	0.01
2655-7656	1	0.02
7658-7659	1	0.02
7661-7662	1	0.03
7662-7663	ī	0.02
7667-7668	1	0.02
7669-7670	Ĺ	0.01
7670-7671	` 1	0.02
	*	0.02
7688-7689	1	0.01
7689-7690	$oldsymbol{1}$	0.01
7690-7691	1	0.60
7691-7692	1	0.01
7692-7693	1	0.01
7694 -769 5	1	0.02
7696-7697	1	0.25
7697-7698	1	0.01
7 70 7-7708	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		0.07
7722-7723	1	0.25
7723-7724	î	0.10
7724-7725	$\hat{1}$	0.01
7707 7700		
7727-7728	$\frac{1}{2}$	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		0.01
7774-7775	BEFORE EXAMINER STAMETS 1	0.01
7775-7776		0.02
7776-777	OIL CONSERVATION DIVISION 1	1.44
7777_7776	MUCANTS EXHIBIT NO. 7 1	0.11
7717-7770	WANTED INC. 1	
7778-7779	CASE NO. 73,13	0.10
7779-7780		0.21
7780-7781	Submitted by 1	0.13

Hearing Date 7-29-Bl

THE PROPERTY OF THE PROPERTY O

DEPTH (ft)	SAMPLE 'FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.01
77837784	1	0.03
7784-7785	1	0.03
7785-7786	1	0.09
7786-7787	$oldsymbol{1}$	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	and the contract of the contra	0.05
7796-7797	1	0.18
7797-7798	. 1	0.61
7798-7799	<u> </u>	0.34
TOTAL	65	9.07

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

CHEMIAL & GEOLOGICAL LABOR TORIES

Farmington

CORE ANALYSIS REPORT

ompany El Paso Natural Gas Company
Vell No. San Juan 30-5 #27-20

ield Wildcat

County Rio Arriba
Depths 7649' - 7799'
Late New Mexico
Drilling Fluid Water Base Mud

C-Crack * Permeability probably LEGENU
H-Fracture caused by existing NF-No Fracture
Shale interlamination's Insufficient Sample

S-Slight St-Stain V-Vertical Vn-Vugs

SAMPLE	LEGEND	DEPIH, FEST	EFFECTIVE POROSITY	PERMEA MILLID		SATUR	ATIONS	CONNATE	(- ·	BILITY
NO.			PERCENT	MORIZONTAL	VERTICAL	RESIDUAL OIL		WATER	ACID	ACID
,		Core No.	1 764	9 - 7710) }		-			
723456	VF VF VF VF VF	7650-51 7651-52 7652-53 7653-54 7654-55 7655-56	7.7 8.5 6.7 7.2 8.6	0.01 0.01 0.01 0.02 0.01 0.02		Trace Trace Trace Trace O	27.6 16.7 12.2 12.4 21.2 15.8	÷		
7	VF .	7658-59	8.8	0.02	•	Trace	12.4			!
8 9	VHF VF	7661-62 7662-63	10.2 9.6	0.03 0.02		0	15.2 19.2	,		
10	VHF	7667-68	10.0	0.02		Trace	20.5	•	-	
11	VHF VHF	7669-70 7670-71	6.5 7.9	0.01 0.02		Trace	15.4 20.6			
13 14 15 16 17	HF HF HF VIIF	7688-89 7689-90 7690-91 7691-92 7692-93	4.9 5.0 5.9 3.7 7.8	0.01 0.01 0.60* 0.01		Trace Trace Trace Trace Trace	26.1 24.2 35.9 94.9 54.7			
18	NF	7694 - 95	9.3	0.02		Trace	14.2	,		
19 20	HF NF	7696 - 97 7697-98	11.4	0.25* 0.01		0	27.7 18.6			: !
21	VHF	7701-02	2.6	0.01		0	62.3		·	: :
22 23 24	VHF VHF VHF	7707-08 7708-09 7709-10	2.0 6.1 5.9	0.01 0.02 0.03		0 C Trace	14.5 16.0 33.9		THE PROPERTY OF THE PROPERTY O	
						:			1	·

C-Crack * Permeability probably Leginne P-Fracture 19-10-10-in caused by existing NP-No Practure O-Open shale interlaminations is in floor Sample

S--Slight S--Stain V--Vertical Va--Vues

				CIONS IS	· · · · · · · · · · · · · · · · · · ·	•				!
NO.	LEGEND	DEPTH, PEET	PERCYIVE POROSITY PORESPACE	PLUMER MILLIO HOMIZONTAL	NILITY NACIFS NERTICAL	PORE TORCE	TIO. 1	CONHAIS	MUD KOLU	BILITY 18 Se ACID
	•	Core No.			Recov	ereá 9†			-	
		No sampl Core No.			Recov	red ó) '				
25 26 27 28 29 30	VIE HE HE HE VHE	7719-20 7720-21 7721-22 7722-23 7723-24 7724-25	3000 14 V	9.01 1.51* 0.07 0.25* 0.10* 0.01		0 0 0 0	30.3 60.7 33.8 60.8 51.6 38.5		·	g tod
! }		Core No.	4 7727	7 - 7738	Recov	red 10'				•
31 32 33 34 35 36 37	VHF VHF VHF VHF HF VF HF	7727-28 7728-29 7729-30 7730-31 7731-32 7732-33 7733-34	0.4.4.0.0.v.o.	0.02 0.04 0.02 0.01 0.04 0.02 0.66*		0 0 0 0 0 0	16.0 11.3 12.2 13.9 12.0 11.0			
		Core No.	5 7738	- 7799	Recove	red 61'	 - -		L	
38 39 40 41	NF NF NF NF	7768-69 ⁴³ 7769-70 7770-71 7771-72 7772-73	10.8 10.5 7.7	0.04 0.04 0.03 0.03 mple tal	con	0 0 0	39.2 45.4 47.1 38.4	41.5		
43456789012345678901	NF NF NF NF NF NF NF NF NF NF NF NF NF N	7772-73 7773-74 7773-74 7775-76 7775-76 7775-79 7775-79 7779-80 7781-82 7781-85 7785-36 7786-87 7786-89 7788-89 7788-89 7788-91 7790-91 7791-92 7792-93	5525677643445766663 8	0.01 0.01 0.02 1.4* 0.11 0.21 0.10 0.23 0.03 0.03 0.05 0.05 0.05 0.05 0.05 0.05		Trace Trace Trace Trace Trace O O CO Trace Trace Trace O O O O O O O O O O O O O O O O O O O	2.1.26.3.3.9.3.16.7.3.3.0.0.0.0.2.1.3 9.1.26.3.3.9.3.16.7.3.3.0.0.0.0.2.1.3 9.1.26.3.3.9.3.16.7.3.3.0.0.0.0.2.1.3 9.1.26.3.3.9.3.16.7.3.3.0.0.0.0.2.1.3 9.1.26.3.3.9.3.16.7.3.3.0.0.0.0.2.1.3	44.1 42.0 44.7 49.5		

El Peso Ratural Gas Company San Juan 30-5 #27-20

Wildcat Rio Arriba County, New Mexico

NF-No Practure

	HHorizontal OOpen		weeken was 1		- No Practure Irs: then it San	iple .			VVertical VuVurs	
AMPLE NO.	LEGEND	DEPTH, FEET	SVIFORON VIICORON SOAREIRON !"	PERMY! MILLIO HORIZONTAL	ARCIES L VEHTICAL	FORL STACE	TIONS TO PORE SPACE	CONNATE	SOLU MUD ACID	NU TO.
		Core No.	1	inued						
62 63 64 65 66 67	VF VF NF NF NF	7793-94 7794-95 7795-96 7796-97 7797-98 7798-99	5.8 4.0 8.3 5.4 9.4	0.02 0.01 0.05 0.18 0.61 0.3 ¹	-	O C, O Trace Trace Trace	39.1 52.3 49.9 51.7 52.1 53.2	46.2		
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LEGEND

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)	CAMPLE POOMAGE (C.)	HORIZONTAL
DECTA (IC)	SAMPLE FOOTAGE (ft)	PERMEABILITY (md)
8075-8076	1	
8076-8077	1 1	0.02
8077-8078		0.01
8078-8079	1	0.01
	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		
8091-8092	1	0.01
	1	0.01
8092-8093	1	0.01
8093-8094	. <u>L</u>	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		
8118-8119	1 1 (-	< 0.01
		0.01
8119-8120	1	0.91
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	ì	0.01
8128-8129	1	0.01
8129-8130	ī	0.02
8130-8130.9	.9	0.01
		3.02
8133-8134	1	0.01
8134-8135	1	0.01
8138-8139	1	0.01
8139-8140	1	0.01
8140-8141	i	
8141-8142	1	0.01
8142-8143	. 1	0.01
8143-8144	1	0.01
8144-8145		0.01
	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	PERSON SYLLAMING OF LANGE IN	0.01
8156-8157	BEFORE EXAMINER STAMETS 1	0.01
8157-8158	OIL CONSERVATION DIVISION 🗍 📲	0.01
12	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	: 0.01
8159-8160	MOANTSEXHIBIT NO. 8 1	
8160-8161	DASE NO. 7313 1	0.01
0040 0040 !]		0.05
8161-8162	Submitted by Nators	0.02
0101 0105 []		7.2
1 1	learing Date 7-29-8)	
Lesson.	राजा प्रदेशका तथा में प्राप्त कुमाने के दिवस स्थान है। अन्य स्थान स्थान स्थान स्थान स्थान स्थान स्थान स्थान स	
	•• •	

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

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8163-8164	1	0.01
8164-8165	, ī	0.02
8165-8166	$\overline{1}$	0.01
8166-8167	ī	0.01
8167-8168	ī	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		0.01
TOTAL	87.7	11.66

ORE LABORATORIES, INC.

Petroleum Reservoir Engineering

	•		
COMPANY.	EL PASO MATURAL GAS COMPA'N	DATE ON 8/30/59	FILE NO RP-3-1065
	SAN JUAN 30-5 No. 28-23 - X	DATE OFF 9/8/59	ENGRS. ENGLISH
FIELD	BLANCO MESA VERLE MAKOTA WILDCAT	FORMATION DAKOTA	ELEV. 6753 DF
COUNTY	RIO ARRIBA STATE N. MEXI	CO DRLG. FLD. OIL EMULSION	CORES DIAMOND
LOCATION.	SEC23 T3CN R5W	REMARKS SAMPLED BY CLI	EST
	SAND LIMESTONE DOLOMITE	CONGLOMERATE O CH VENTICAL TRACTURE	HERT FINANCE
	use, this tapart is made. The interpretations or apinious explicit	rightors and instruct supplied by the close to whom, and for whose accitished ad represent the best publiment of Core Laboratoles, Line tall ceress and amount summe no responsibility and makes an existent or representations on to the pro-	to Gha excepted.

it (ee Tabershirts, lint, and its afficest and employees, assume no respect, butly and make ne variety or representations as to the productivity, proper exterior, or profitableness of any oil, gos or other mineral well or sand as connection with which such report is used or relied upon.

COMPLETION COREGRAPH

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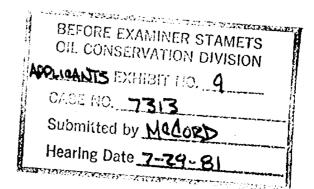
EXHIBIT NO. 9

Company: El Paŝo 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	0.01
7638-7639	ĺ	0.05
7639-7640	1	0.07
7640-7641	1	0.01
7641-7642	1	0.10
7642-7643	1	< 0.01
7643-7644	1	< 0.01
7644-7645	<u> </u>	0.01 < 0.01
7645-7646	1	0.01
7646-7647	1	< 0.01 < 0.01
7647-7648	î	< 0.01 < 0.01
7716-7717	1	0.13
7717-7718	$\overline{\overline{1}}$	0.04
7718-7719	$\frac{1}{1}$	0.01
7719-7720	$ar{ extbf{i}}$	0.90
7720-7721	$\overline{1}$	< 0.01
7721-7722	$ar{f 1}$.	< 0.01
7722-7723	1	< 0.01 < 0.01
7723-7724	* : 1	< 0.01 < 0.01
7724-7725	1	< 0.01
7725–7726	1	4 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	<u> 1</u>	1.00
TOTAL	34	5.90

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



CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

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LOCATION.	SFC 33 - T30N - R6W		REMARKS	SAMPLED BY CLI	ent	
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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 7914-7916	2 2	0.05
7916-7923 7923-7928	7 5	0.34 0.05
7928-7930 7930-7931	2 1	0.18 0.59 0.05
7932-7936	4	0.05
TOTAL	24	

Weighted Total = 3.51 md

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

BEFORE EXAMINER STAMETS
CIL CONSERVATION DIVISION

WOLLEANTS EXHIBIT MO. 10

CASE NO. 7313

Submitted by Helms

Hearing Date 7-29-81

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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

	· · · · · · · · · · · · · · · · · · ·	7	
DEPTH (ft)	SAMPLE F	OOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7904.5-790)5	E	0.00
7905-7906	,,,	.5	0.02
7906-7907		1	0.02
		1	< 0.01
7907-7908		1	< .0.01
7908-7909		1	€, 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	·	ī	< 0.01
7916-7917		1	
7917-7918	•	1	< 0.01
7717 7710	\$	1	< 0.01
7939-7940		•	
7940-7941		1	< 0.01
		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	
7964-7965			0.01
7965-7966		1	0.01
	•	1	0.01
7966-7967	•	1	0.01
7967-7968		1	0.05
7070 7070		_	*
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
		1	0.02
8005-8006		1	2 23
8006-8007		1	0.07
		1	0.01
8007-8008		1	0.01
8008-8009		1	< 0.01
8009-8010		1	< 0.01
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8014-80	THE THE RESIDENCE OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPERTY OF THE PROPE		0.28
8015-8016	BEFORE EXAMINER STAMETS	1	0.23
8016-8017	OIL CONSERVATION DIVISION	4	0.54
8017-8018	OF CONSTANTION DIAISION	1 .	0.06
r i	PLICANTS EXHIBIT NO. 11	* *	
	CASE NO. 7313		
	Submitted by NeCorp		
11		+15	

Hearing Date 7-29-8

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

	• •	
DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8022-8023	1	< 0.01
8023-8024	î	< 0.01
8024-8025	1	< 0.01
8025-8026	i .	< 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		0.04
8035-8036	ī ·	0.05
8036-8037	ī	0.07
8037-8038	1	< 0.01
8038-8039	î	0.14
8039-8040	ī	0.35
8040-8041	1	< 0.01
TOTAL	62.5	3.60
Ave. $K = \frac{3.60}{10.05} = 0.05$	8 md	

ORE LABORATORIES, INC.

Petroleum Reservoir Engineering

COMPANY_EL PASO NATURAL GAS COMPANY DATE ON7/18/59 FILE NO. RP-3-1037	
WELLSAN JUAN 31-6 NO. 16-33 DATE OFF_7/22/59 ENGRS_ENGLISH_	
FIELD WILDCAT (BLANCO MESA VERDE DAKOTA) FORMATION DAKOTA ELEV. 64991 DF	
COUNTYRIO_ARRIBA STATE NEW MEX. DRLG. FLD. OIL EMULSION MUDCORESDIAMOND	
LOCATION_SEC33-T31N-R6W REMARKS _SAMPLED_BY_REPRESENTATIVE_OF_CLIENT	T.
SAND LIMESTONE CONGLOMERATE O.S. CHERT	
SHALE FRACTURE FRACTURE	
These analyses, apmeans or interpretations are based on absertations and material supplied by the client to whom, and for whose assissive and confidential use, this report is made. The interpretations or operated represent the best produment of Care Cobinetaries, let. cott ories and antissions recopied; but Care Cobinetaries, i.e. and in other and ambient ories and employees, assume no to responsibility and make no worship or trappresationance as to be productively, proper against one, as profitableness of any oil, goe or other mineral wall or sand in connection with which such report is used at reliad upon	

COMPLETION CORECDAPI

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2 05-06 0.02 3.8 0.0 36.8 3 06-07 <0.01 2.1 0.0 81.0	H+### i
4 07-08 <0.01 3.6 0.0 44.5	440
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	82 11111
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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
	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		0.01
7842-7843	, <u>î</u>	
7843-7844	-	0.01
	_1	<u>1.50</u>
TOTAL	13	1.62

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

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION

WICANTS, EXHIBIT NO. 13

CASE NO. 7313

Submitted by No. 12

Hearing Date 7-29-8

SUND DESCRIPTIONS

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COho #1 6990-7039. Recovered 21' blk. shale, cottom 6' sli bandy.
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CORE #2 . 7039-7042. Core jamued in bul. Recovered 2' olk shale.

CORE #3 7042-7045;. Core jamed in bbl. Recovered 3' blk snale.

CORE #4 7800-7630. Recovered 25 1/21.

- 1. snale, gry-bix, platy, sli sandy, micaceous, or coal
- 2. wand, gry, vig, cale, sii silty, scattered mica., duse
- 3. Shale, Sin, Michaelen, Would bered sand lenses, 15% sand
- 4. sand, gry, vfg, calc, very silty, snale stringers, abdt nica, once, tite...
- 5. same
- 6. sine, 20% blk shale
- 7. shale and samu in alternating layers, predominately shale
- 8. shale, blk, sli sandy, calc, sicaceous
- 9. same, W/peurly pelecypod frags
- 10. saus
- 11. 2 400
- 12. same
- 13.. same
- 14. same, concentric frictures parallel to bedding
- 15. limestone, buff-bra, dase, silie, crypto-kla, horizontal fractures
- 16. of le, bla, sli sandy, micaceous
- 17. wame, concentric frictures parallel to bedding
- 18. same, no fractures
- 19. shale and sand in alternating layers, p. dom. shale
- 20. shale and take in alternating layers, predom. sand
- 21. sand, gry-an, ig, hard, dnse, scattered intergranular poro
- 22. same, sli slity, w/norizontal fractures
- 23. same, shaley (40%), micaccous
- 24. shale, blk, nicaceous (75%); sand (25%)
- 25. sand, gry, fg, hard, micaceous, a/abut pyrite
- 26. same (60%); smale (40%)

COLE #5 7830-7831. No recovery.

CORE #6 7801-7844. Fall recovery.

- 1. Jand, Gry-wh, fg, hard horiz. True, or fair intergranular poro
- 2. same, within smale portings, tr fair poro
- 3. same, no Prac, tr Pair poro
- 4. same, sli silty, triair poro
- 5; same
- 6. same, fair poro
- 7. same, tr fair poro
- 8. 3ane
- y. same

- 11. Sine, w/thin shile partings 12. Same, ir fair poro 13. Sume, shale (20%), ir poro

CORE #7 784,-7844. Full recovery.

- 1. sand, cry-an, fg, hard, or intergranular poro 2. same, w/scat shale partings and horiz frac
- 3. 33.06
- 3:iie 4.

ABBREVIATIONS USED IN SEPRE & COME DESCRIPTION

A - angular abdt - sbundant bent - bentonite (itic) olk - black
brn - brown
calc - calcareous
dase - dense fg - fine grained foss - fossiliferous
frac - fractured
frag - fragmont(3)
fx - finely crystalline glau - glauconite(ic) grn - green gry - gray horiz - horizontal IGR - intergranular incl - inclusions

ig - large grained

ls - limestone Ag - medium grained poro - porosity pyr - pyrite qtzitic - quarteitic R - rounded SA - subangular scat - scattored sdy - sandy sh - shale silie - siliceous sli - alignt Sk - subrounded sa - sandstone tr - trace V - very vert - vertical wh - white xln - crystalline

בלוע בונענהונה שוליט בחדה

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1	7E32	J.31	4.20	4.65
2	7833	J.J1	2.75	3.70
3	7834	0.01	4.10	4.42
. 4	7835	0.01	1.17	2.08
<u> </u>	7836	↓.)1	1.97	∠.ઇ1
6	7837	0.01	4.28	50 ₄ال
7	78 38	ં ંો	`3 . 08	7.80
8	7839	0.01	8.50	9.30
9	78 40	ŭ . 31	7.20	i. y 0
10	7841	0.01	2.76	گو • ز
11	7842	3 .31 .	2.65	زر د
12	784 3 .	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.

DEFORE EXAMINER STAMETS OIL CONSERVATION DIVISION

APPUGANTS EXHIBIT NO. 13

CASE NO. 7313

Submitted by Meters

Hoaring Date 7-29-8

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 Clifts formation, Choza Mesa field, Rio Arniba 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. 1-2 Overburden pressure causes only a small decrease in porosity, which can usually be ignored. 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 or nonexistent. 3

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70° C), the gas (N₂) 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. 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 realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

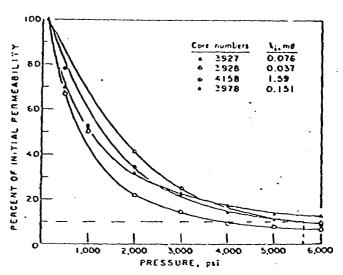


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

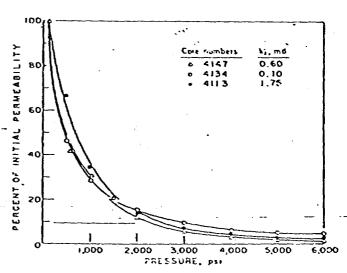


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

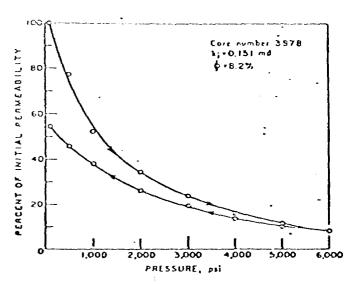


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1-EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Over	buiden Pies	sure (psi);		300	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	kit			Pe	meability (mo	n)		
Gashuggy										
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	0.073	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
4346**	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	0.922	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	9.9	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

^{*}Number denotes depth in feet

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 researcheris^{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 al-

though 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

ation (percent):	0	20	40	60
(ba) Liezznis		Pe:meabi	lity (md)	
100	0.115	0.099	0.041	0.0023
3,000	0.026	0.023	0.009	0.0005
6,000	0.012	0.010	0.003	0.0002
100	0.112	0.080	0.034	0.011
3,000	0.036	0.026	0.011	0.004
6,000	0.013	0.009	0.004	0.0013
100	0.447	0.335	0.156	0.045
3,000	0.075	0.056	0.026	0.0074
6,000	0.027	0.020	0.010	0.0026
el				
100	0.038	0.030	0.014	0.0042
3,000	0.012	0.0098	0.0043	0.0013
6,000	0 0070	0.0056	0.0025	\$000.0
100	0.074	0.054	0.017	0.006
3,000	0.027	0.020	0.008	0.002
6,000	0.020	0.015	0.006	0.002
100	0.100	0.074	0.029	0.003
3,000	0.028	0.020	0.008	0.0008
6,000	0.017	0.013	0.005	0 000\$
	Pressure (psi) 100 3,000 6,000 100 3,000 6,000 100 3,000 6,000 100 3,000 6,000 100 3,000 6,000 100 3,000 6,000	Pressure (ps) 100 0.115 3,000 0.026 6,000 0.012 100 0.112 3,000 0.036 6,000 0.013 100 0.447 3,000 0.075 6,000 0.027 el 100 0.038 3,000 0.012 6,000 0.0070 100 0.074 3,000 0.027 6,000 0.027 6,000 0.027 6,000 0.028	Pressure (psi) Permeable 100 0.115 0.099 3,000 0.026 0.023 6,000 0.012 0.010 100 0.112 0.080 3,000 0.036 0.026 6,000 0.013 0.009 100 0.447 0.335 3,000 0.075 0.056 6,000 0.027 0.020 el 100 0.038 0.030 3,000 0.012 0.0096 6,000 0.0070 0.0056 100 0.074 0.054 3,000 0.027 0.020 6,000 0.027 0.020 6,000 0.027 0.020 6,000 0.027 0.020 6,000 0.027 0.020 6,000 0.027 0.020 6,000 0.028 0.020	Pressure (psi) 100 0.115 0.099 0.041 3,000 0.026 0.023 0.009 6,000 0.012 0.010 0.034 3,000 0.036 0.026 0.021 0.034 3,000 0.036 0.026 0.011 6,000 0.013 0.003 0.004 100 0.447 0.335 0.156 3,000 0.075 0.056 0.026 6,000 0.027 0.020 0.010 ell 100 0.038 0.030 0.014 3,000 0.012 0.0096 0.0010 ell 3,000 0.012 0.0096 0.0043 6,000 0.0070 0.0056 0.0025 100 0.074 0.054 0.0070 0.008 6,000 0.0070 0.0074 0.054 0.008 6,000 0.0070 0.0074 0.008 6,000 0.0000 0.0074 0.0064 0.0074 0.0064 0.0074 0.0068

^{*}Slightly fractured

initial permeability.

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 insitu 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

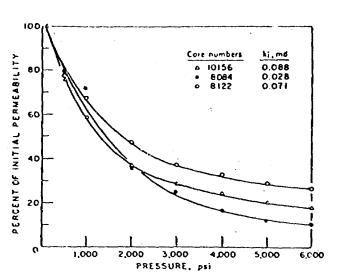


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

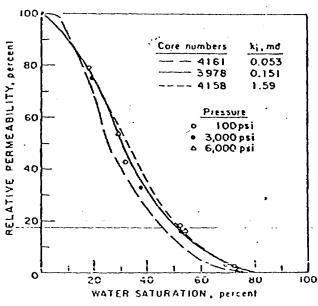


Fig. 5-Relative gas permeability of Gasbuggy cores.

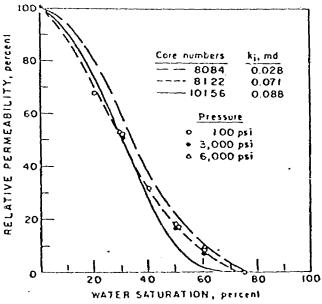


Fig. 6-Relative gas permeability of Wagon Wheel cores.

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 pressureeffect 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

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.

References

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- 4. Wilson, J. W.: "Determination of Relative Permeability Under Simulated Reservoir Conditions," AIChE Jour. (1956) 2, 94.
- Fatt, I.: "The Effect of Overburden Pressure on Relative Permeability," Trans., AIME (1953) 198, 325-326.
 API Recommended Practice for Core-Analysis Procedure.
- API RP 40, Dallas (1960) 35.

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 jublished 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 31 7950 feet in the Rosa Refore EXAMINER STAMETS

Area is approximately 5600 psi. Office EXAMINER STAMETS

APPLICANTS EXHIBIT FO. 14

CASE NO. 7313 Submitted by **McCoo**

Hearing Date 7-29-6

Entering the graph in Pigure 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 in-situ permeability (10% of laboratory) = 0.012 md

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION

APPLICANTS EXHIBIT NO. IS

CASE NO. 7313

Submitted by House

Hearing Date 7-29-81

PRINCIPAL EXHIBIT NO. No. CASE NO. 1313
Submitted by No. (1952) BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION

ROSA TIGHT GAS AREA

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14 WELL AVERAGE		Natural Production Tests
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423 288	PRODUCTION RATE NATURAL (MCFPD) 527 161 666 TSTM 338 338 264 2174 128 370 241 TSTM 338 370	
2460 2525	PRODUCTION KATE AFTER FRAC (MCFPD) 2506 1703 3944 855 2635 2456 1209 1610* 2035 3691 2828 2557 2643 3770	

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

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

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 $\frac{(Pe^2 - Pwf^2)}{Ug T - 2 - ln - (.61 - re/rw)}$

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 $0.020 \,\mathrm{cp}$ = bottom hole temperature - calculated to be $667^{\mathrm{O}}\mathrm{R}$

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 2

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

	BEFORE EXAMINER STAMETS
	OIL CONSERVATION DIVISION
	MPLICALSTS EXHIBIT NO. 17
	CASE NO. 7313
	Submitted by MalorD
	Hearing Date 7-29-81
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STATE OF NEW MEXICO ENERGY AND MINERALS DEPARTMENT OIL CONSERVATION DIVISION

POST OFFICE BOX 2008 STATE LAND OFFICE BUILDING SANTA FE, NEW MEXICO 87501 (505) 827-2434

Mr. William F. Carr Campbell, Byrd & Black Satorneys at Law 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 horewith 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 A. iba 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:

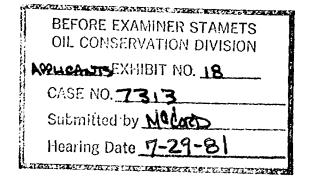
1.	T30N-R2W	Sections 1 through 36: All
2.	T30N-R3W	Sections 1 through 36: All
3.	T30N-R4W	Sections 1 through 36: All
4.	T30N-R5W	Sections 1 through 36: All
5.	T30N-R6W	Sections 1 through 36: All
6.	T30N-R7W	Sections 1 through 36: All
7.	T31N-R2W	Sections 1-through 36: - All
8.	T31N-R3W	Sections 1 through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

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

Sections 1 through 36:

All

12. T31N-R7W



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 port 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 § 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 1976.

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 develop- ment in a west-east direction.
6	Cross Section B-B'	Show Dakota formation develor- ment 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 THIBIT NO. 3 CASE NO. 73.13 Submitted by Medolb EXHIBIT NO. 3

ROSA TIGHT GAS AREA WELLS

Submitted by Hechel

Submitted by NegoRD Hearing Date 7-29-81		LOCATION	DAKOTA DEPTH	IP DATE	IP GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
	5	NW/NW 34 30-3	8213	79/60	D&A	8 1 1	!
Carson #2 NW	**	NW/SW 7 30-4	8083	62/60	0/698	302/0	0/550.
39 San Juan 30-4 Unit	~	SE/NW 18 30-4	8425	02/81	2506/0	New Well	.
1 Schalk-76	SW/NW	/NW 25, 30-4	8675	02/73	D&A	-	-
#1 Carson	NW/SW	/SW 1 30-5	8030	10/69	2129/0	129/0	.518/0
Schal.k #54	SE/NE	/NE 2 30-5	8018	01/73	2501/0	111/0	.297/0
Schalk #55	NE/NE	/NE 3 30-5	7940	03/73	3298/0	34/0	,126/0
Cat Draw #1 S	3/M	SW/SW 4 30-5	7780	89/60	2074/0	IS	.186/0
39 San Juan 30-5 Unit	W/W	SW/NE 7 30-5	7686	07/75	1703/0	0/19	.123/0
37 San Juan 30-5 Unit	NE/SW	/sw 8 30-5	7688	01/74	3944/0	87/0	.503/0
70 San Juan 30-5 Unit	ne/ne	NE 9 30-5	7752	1,2/80	1584/0	New Well	i
49 San Juan 30-5 Unit	SW/SW	/sw 9 30-5	7683	12/80	855/0	New Well	[
73 San Juan 30-5 Unit	NW/NE	NE 10 30-5	7919	03/81	2635/0	New Well	ļ
72 San Juan 30-5 Unit	SW/s	SW/SW 10 30-5	7790	04/81	2456/0	New Well	!
Schalk #57	NE/ħ	NE/NW 12 30-5	8009	c7/73	5107/0	148/0	.452/0
52 San Juan 30-5 Unit	SE/S	SE/SW 15 30-5	7920	03/81	2679/0	New Well	1
53 San Juan 30-5 Unit	NE/S	NE/SW 16 30-5	7685	12/80	1209/0	New Well	:
47 San Juan 30-5 Unit	NW/s	NW/SW 17 30-5	7794	08/75	1610/0	129/0	.235/0

COMPANY	WELL NAME	LOCATION	DAKOTA DEFTH	IP DATE	IP CAS/OIL MCFPD/BOPD	1980 PROD.	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	# 1	}
Northwest Pipeline Corp.	48 San Juan 30-5 Unit	NW/NE 20 30-5	7790	01/80	3691/0	New Well	ł
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.)	1	
Northwest Pipeline Corp.	Rosa Unit #42	SW/NE 19 31-4	not given	11/61	D&A		1 ? [
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.)		1
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	!	ł
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	1

WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	CUMULATIVE 01-01-81 BCF/BO
Rosa Unit #70	NW/NW 10 31-5	8162	01/66	1500/0	261/0	.248/0
Rosa Unit #48	SW/SE 11 31-5	8151	12/62	3207/0	326/0	.218/0
Rosa Unit #40	SW/NW 11 31-5	8358	07/61	3560/0	271/0	.216/0
Rosa Unit #61	SE/SW 13 31-5	8124	11/77	337/0	55/0	.074/0
Rosa Unit #65	NE/NE 17 31-5	7870	08/78	3095/0	163/0	.104/0
Rosa Unit #68	NW/SW 17 31-5	not given	08/80	5757/0	609/0	.093/0
Rosa Unit #62	NE/NW 25 31-5	8088	11/77	342/0	82/0	106/0
Rosa Unit #64	NE/NE 29 31-5	7950	10/78	1843/0	175/0	.132/0
Rosa Unit #52	NW/NW 33 31-5	7980	02/70	2401/0	248/0	1.095/0
Rosa Unit #55	NE/SE 34 31-5	8056	10/74	264/0	167/0	.386/0
Rosa Unit #56	SW/NW 35 31-5	8200	1.1/75	675/0	96/0	.232/26
Rosa Unit #54	NE/SW 36 31-5	8284	09/74	304/0	IS	.029/0
Rosa Unit 35-X	NE/SW 5 31-6	7822	10/59	D&A Dak. MV Comp.		1
Rosa Unit #36	SE/NE 11 31-6	7955	12/59	P&A MV Comp.	1	
Rosa Unit #1	SW/SE 11 31-6	7865	09/52	560/0 (P&A)		}
Rosa Unit #66	NW/SW 13 31-6	7957	08/78	4427/0	245/0	.928/0
Rosa Unit #69	NW/NW 16 31-6	7918	09/80	P&A	1	}
79 San Juan 31-6 Unit	NE/SW 22 31-6	7757	03/81	1858/0	New Well	
	WELL NAME Rosa Unit #48 Rosa Unit #40 Rosa Unit #61 Rosa Unit #65 Rosa Unit #68 Rosa Unit #62 Rosa Unit #52 Rosa Unit #56 Rosa Unit #56 Rosa Unit #56 Rosa Unit #36 Rosa Unit #66 Rosa Unit #66 Rosa Unit #66 Rosa Unit #66 Rosa Unit #69 79 San Juan 31-6 Unit	WELL NAME LOCAT Unit #70 NW/NW 10 Unit #48 SW/SE 11 Unit #61 SW/NW 11 Unit #65 NE/NW 11 Unit #62 NE/NW 12 Unit #52 NE/NW 25 Unit #55 NE/NE 29 Unit #56 NE/SE 34 Unit #56 NE/SW 35 Unit #66 NE/SW 36 Unit #66 NE/SW 11 Unit #69 NW/NW 16 NE/SW 22 NE/SW 22	WELL NAME LOCATION Unit #48 SW/SE 11 31-5 Unit #40 SW/SE 11 31-5 Unit #61 SE/SW 13 31-5 Unit #62 NE/NE 17 31-5 Unit #62 NE/NE 17 31-5 Unit #52 NE/NE 29 31-5 Unit #55 NE/NE 29 31-5 Unit #56 NE/SE 34 31-5 Unit #54 NE/SW 36 31-5 Unit #36 SE/NE 11 31-6 Unit #66 NW/SE 11 31-6 Unit #66 NW/SE 11 31-6 Unit #69 NW/NW 16 31-6 Unit #69 NW/NW 16 31-6	WELL NAME LOCATION DAKOTA DEPTH IP Unit #48 SW/SE 11 31-5 8162 0 Unit #46 SW/SE 11 31-5 8151 1 Unit #65 NE/NW 11 31-5 8124 1 Unit #66 NW/SW 17 31-5 7870 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#55 NE/NW 35 31-5 8086 11/77 3 Unit #56 NE/SW 36 31-5 8086 11/77 3 Unit #56 NE/SW 36 31-5 8086 10/74 3 Unit #56 NE/SW 36 31-5 8086 10/74 3 Unit #66 NE/SW 36 31-5 8086 10/74 3 Unit #66 NW/SW 13 31-6 7955 10/59 2 Unit #66 NW/SW 13 31-6	WELL NAME LOCATION DAKOTA DEPTH IT PATE LIF PATE CASTON CASTON CASTON DEPTH CASTON CASTON DEPTH CASTON CASTON DEPTH CASTON CASTON CASTON DEPTH CASTON CASTON CASTON DEPTH CASTON CASTON CASTON DEPTH CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON CASTON 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COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	GAS/OIL MCFPD/BOPD	1980 PROD.	CUMULATIVE 01-01-81 BCF/BO
Northwest Pipeline Corp.	Roga Unit #51	NE/NW 23 31-6	7823	01/70	1385/0	1.70/0	.736/0
Northwest Pipeline Corp.	36 San Juan 31-6 Unit	NE/NE 27 31-6	7806	03/81	2557/0	New Well	1
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	<u> </u>
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	27/9	.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

	DAKOTA FO	RMATION CORE D	ATA	
DEPTH (ft)	SAMPL	E FOOTAGE (ft)	•	HORIZONTAL PERMEABILITY (md)
7650-7651		1	4	0.01
7651-7652		î		0.01
7652-7653		1		0.01
7653-7654		1		0.01
7654-7655	•	1		0.02
7655-7656		1		0.01
				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		
7670-7671		$\frac{1}{1}$		0.01 0.02
7688-7689		1	•	0.01
7689-7690	•	1		
7690-7691 °		1		0.01
7691-7692		î	•	0.60
7692-7693		i		0.01
7694-7695				0.01
		1		0.02
7696-7697		i		0.25
7697-7698		1		0.01
77077708		1	X.	0.01
7708-7709		1		0.01
7709-7710		1		0.03
7719-7720		1		0.01
7720-7721		ī		1.51
7721-7722		ī		
7722-7723		î		0.07
7723-7724		i		0.25
7724-7725		1		0.10
7727-7728				0.01
		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	MEDICALISM DESCRIPTION DE LA COMPENSACIONE DE LA COMPENSACIONE DE LA COMPENSACIONE DE LA COMPENSACIONE DE LA C	war)		0.01
1115-146 DECOR	E EXAMINER STAMETS	į.		0.02
7770 7787	NSERVATION DIVISION	\$		1.44
		Ä.		0.11
7778-7779	SEXHIBIT NO. 7	jį.		0.10
7779-7780 ACCESSION		ì		0.21
7780-77 B1 CASE N	(0.7 <u>1315</u>			0.13
Submit	ted by Mcloso			
15		E2		

Hearing Date 7-29-81

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DEPTH (ft)	SAMPLE 'FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.01
77837784	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	ī	0.06
7790-7791		0.05
7791-7792	î	0.03
7792-7793	î	0.03
7793-7794	1	
7794-7795	1	0.02
7795-7796	i	0.01
7796-7797	1	0.05
7797-7798	1	0.18
7798-7799	. 1	0.61
1170 1197		0.34
TOTAL	65	9-07
Avg. $K = \frac{9.07}{65} = 0.140$	md.	

CHEMIC L & GEOLOGICAL LABOR. ORIES Farmington

CORE ANALYSIS REPORT

ompany El Paso Natural Gas Company

Nell No. San Juan 30-5 #27-20

ield Wildcat Formation Dakota

County Rio Arriba Depths 7549' - 7799'

atc. New Mexico Drilling Fluid Water Base Mud

C - Crack * Permeability probably LEGEND S--Slight Statement Caused by existing NF-No Fracture V-Vertical Vin-Vozs shale interlaminations-Insufficient Sample

1	1		EFFECTIVE	PERMEADILITY	927116	ANONS		1 50111	BILITY
HO.	LEGEND	DEPIH, FEET,	FOROSITY PERCENT	MILLIDARCIES HORIZONTAL VERTICAL	S POSE SPACE	TOTAL WATER	CONNATE	ACID ACID	13 %
-		Core No.	1 764	9 - 7710					<u>i</u>
123456	VF NF VF VF VF	7650-51 7651-52 7652-53 7653-54 7654-55 7655-56	7.7 8.7 7.7 8.6 7.7 8.6	0.01 0.01 0.01 0.02 0.01 0.02	Trace Trace Trace Trace O	27.8 16.7 12.2 12.4 21.2 15.8			
7	VF	7658-59	8.8	0.02	Trace	12.4			
8 9	VHF VF	7661-62 7662-63	10.2 9.6	0.03 0.02	0	15.2 19.2			
10	VHF	7667-68	10,0	0.02	Trace	20.5			
11 12	VHF VHF	7669-70 7670-71	6.5 7.9	0.01 0.02	Trace	15.4 20.6			
13 14 15 16 17	HF HF HF HF VHF	7688-89 7689-90 7690-91 7691-92 7692-93	4.9 5.0 5.7 7.8	0.01 0.01 0.60* 0.01 0.01	Trace Trace Trace Trace Trace	26.1 24.2 35.9 94.9 54.7			
18	NF	7694 - 95	9.3	0.02	Trace	14.2			
19 20	HF NF	7696 - 97 7657 - 98	11. ¹ 4 6.3	0.25* 0.01	0	27.7 18.6	,		!
21	VHF	7701 - 02 *	2.6	0.01	O	62.3	· .		• •
22 23 24	VHF VHF VHF	7707-08 7708-09 7709-10	2.0 6.1 5.9	0.01 0.02 0.03	0 C Trace	14.5 16.0 33.9			:
					:				•

C-Clack * Permeability probably LEGENTS BY FINANCE BETTER CAUSED by existing NF-No Flat Gire O -Open shale interlaminations is to the Control Sample

S--Slight St-State V--Vertical Vu---Vogs

HPLE HO.	LEGEND	DEPTH, FEET .	POROSITY CORESPACE	ATHRITAL STATES	NACIES Nebtical	PER HUNE OIL	TO 3. TO POST STAGE:	TONHATE PATAW	EOLU! MUD ACID	15 %
		Core No.		_		ered 9'				7610
		No sampl	es ana	Lyzed						
		Core No.	3 771	7727	Recov	ered 6½		,		
567890	VIE HE HE HE VIE VIE	7719-20 7720-21 7721-22 7722-23 7723-24 7724-25	32.7.4.5.6 32.7.4.5.6	0.01 1.51* 0.07 0.25* 0.10* 0.01		00000	30.3 60.7 33.8 60.8 51.6 38.5			
		Core No.	4 7727	' - 7738	Recov	red 10				
1234567	VHF VHF VHC VHF HF VF HF	7727-28 7728-29 7729-30 7730-31 7731-32 7732-33 7733-34	335130	0.02 0.04 0.02 0.01 0.04 0.02 0.66*		0 0 0 0 0	16.0 11.3 11.3 12.2 13.9 12.0			3
		Core No.	5 7738	- 7799	Recove	red 61'			-	
8901 28+557390128+557390	KITHU ANTEUN NING NEUTON NING NEUTON NING NEUTON NING NEUTON NING NING NING NING NING NING NING NI		10.8 10.5 7.7	0.04 0.03 0.03 0.01 0.01 0.01 0.02 1.44* 0.11 0.10 0.13 0.03 0.05 0.05 0.05 0.05 0.05 0.05 0.05 0.05		O O O O O O O O O O O O O O O O O O O	34.14 2.2633.9316.73300.96213 95.78 98.593.9316.73300.96213 94.14 2.2633.9316.73300.96213	42.5 42.0 1.4.7 49.5		

El Paso Natural das Company San Juan 30-5 #27-20 Wildell Rio Arriba-County, New Mexico

	TS - 1: c. Circu et Sample										
SAMPL NO.	E LEACHD	DEPTH, PEET 1	TIPLOTON THEORON	PERHE MILLID HORIZONTAL	ADILITY ADGIEN VENTICAL	SATURE FORE SPACE HESIDUAL OIL	TIONS TO PORE SPACE TOTAL WATER	COYNATE	NUD ACID	IU W. ACID	
		Core No.	1	inued							
62 63 64 65 66 67	VF VF NF NF NF	7793-94 7794-95 7795-96 7796-97 7797-98 7798-99	5.0354. 80354.	0.02 0.01 0.05 0.18 0.61 0.3 ¹		O C O Trace Trace	39.1 52.3 49.9 51.7 52.1 53.2	46.2			
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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	$\overline{1}$	0.01
8080-8081	$\bar{1}$	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	·	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	$\overline{1}$	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 F	BEFORE EXAMINER STAMETS 1	. 0.01
8156-8157	DIL CONSERVATION DIVISION 1	0.01
	• • • • • • • • • • • • • • • • • • • •	0.01
8158-8159 1994	CANTS EXCHIBIT NO. B 1	0.01
8159-8160	ASE NO. 73/3	0.01
8160-8161	1	0.05
8161-8162	Submitted by McCores 1	0.02
8162-8163	1.00-81	7.2
A DIVINE	learing Date 1-29-81 1	7 * **

	• •	HORIZONTAL
DEPTH (ft)	SAMPLE FOOTAGE (ft)	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	ī	0.24
8192-8193	ī	0.01
8193-8194	$\hat{1}$	0.07
	_	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	$\overline{1}$	0.01
8224-8225	$ar{f 1}$	0.01
8225-8226	1	0.01
8226-8227	1	0.01
		3.31
8229-8230	1	0.01
8230-8231	1	0.02
8238-8239		6.63
8239-8240	1	0.01
8240-8241	1	0.01
8241-8242	·	0.01
8242-8243	1	0.01
0242-024J	1	0.28
8246-8247	1	0.01
8247-8248	_1_	0.01
TOTAL	87.7	11.66
		`

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

ORE LABORATORIES, INC.

Detroleum Reservoir Engineering

	•		
COMPANY_	EL PASO MATURAL GAS COMPANY	DATE ON6/30/59	FILE NO. RP-3-1065
	SAN JUAN 30-5 No. 28-23 - X	DATE OFF 9/8/59	ENGRS ENGLISH
FIELD	BLANCO MESA VERSE SAKOTA WILDCAT	FORMATION DAKOTA	. ELEV. 6753' DF
COUNTY	RIO ARRIBA STATE N.MEXIC	O DRLG. FLD. OIL EMULSION	CORES DIAMOND
LOCATION_	SEC23 T3ON R5W	REMARKS SAMPLED BY CLI	ENT
	SAND LIMESTONE C	ONGLOMERATE	HERT HERT
\$	SHALE DOLOMITE 7, 7	VERTICAL PRACTURE	
•	These medicals appropriate or reference and based on absent	ations and material supplied by the stant to whom and for whose enstraine	and sant-draval

House analysis, applicable as interpretations are board on characters and material supplied by the first in home and fir image assistance and confidential maje, this report is made. The interpretation or applicable presents the best progress of Control and control and amplicable to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the first supplied to the

COMPLETION COREGRAPH

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3						4			Pl	ERM	EABI	LIDA						Ţ			ATER			
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333	DEPTH	PERM.) T: S	RESH SATUR	ATION	BOYLETS	Ī			PO	ROSI			X							URAT			
SAMPLE	FEET .	MD.	F04051T	OIL	TOTAL	LAW POROSITY	PROD			40	30	CEN.	20	1	n	0	ı	0	20			60		кC.
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1	8075-76	0.02	4.6	1	32.6				$\ \ $	$\{ \} \}$					$\coprod_{i=1}^{n}$	4//	· · · · ·	<u> </u>		H		∦	} -	
3	76-77 77-78	♥0.01	3.4		61.8 78.6					╢				Ш	HE	φ.\ 1	7	$\parallel \parallel$	╫	ዠ	[╫	┧╂╅	i
4	78-79	€.01	2.5	 	48.0				╫	H					 	y		[#	ĬĬ	卄	代	#	#1	{
5	79-80	₹0.01	7.6		1¢.8					1					XÍ	9 '8	080	(#1	<u> </u>	177		*	ţ
6_	80-81	_ <0.01_	7.0	0.0	21.4										Ki.	4//			\prod	Ш			ķ	;
7_	81-82	₹0.01	4.5	0.0	33.4]]]]				Ì	þ .\	//· · ·	X	<u> </u>		Щį		9	:
8	82-83	₹0.01	4.3		34.9			-							1	þ.	11	K! 				$\prod_{i=1}^{n}$	N	j
.9	83-84	_∅,01_	5.5		20.0			}}}		$\{i\}$			- -		K	φ	· · · ·	-11			╁┼┆┩		+	
10	84-85	€0.01	5.2	1	21.2 50.0	:	<u> </u>]								3/18	085	1	╫	$\dagger \dagger \dagger$	118	#	111	Ť
11	85-86	0.01	2.4	- 0.2	55.0					$\ \ \ $		-	+ +		$\dagger \dagger \dagger$		\			##	+"	#	111	
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12	8090-91	0.01	2.2		81.8	f .				lil						1 /	\	W	R	##	╂╫╅	- -		
13	91 - 92 92 - 93	♥.01 ♥.01	13.7 15.7	13.5	78.4 87.7						╣╂			!+			A_{i}^{i}	J.P.	作	╫	-	:		i
14.	93-94	0.01	; 4.2	ì	90.5	1-		┧┞╁╌	-	!					11.	\$. //	Į.	- []	111	114			•
16	94-95	<0.01	4.3	4.7	88.4					Ш	Ш				İİX	2\3	 09 5	χç			Ш	Ш	Ш	Ì.
17	95-96	0.01	4.8	4.2	87.5								<u> </u>			1	\	×¢.	.	Ш				111
18	96-96.8	<0.01	5.7	0.0	91.3		ļ									<u> </u>	· · ·	10		$\coprod_{i=1}^{n}$		\prod		Ш
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19	8 <u>115.5-16</u> v		2,2	0.0											X		, A					
50	16-17	0.03	5.0	10.0 7						1		111			\ \f\	/7:::	111	D.	\mathbb{H}			.
. 5 1	17-18 18-19	<0.01 <0.01	2.5	18.2 5					\prod	+	$\frac{1}{1}$	- - -						111		111	\mathbb{H}	
23	19-20	₹0.01	3.4	0.0 2 5.9 7					++		$\left\{ \left \cdot \right \right\}$	- -	-			812	ŴΠ		$\parallel \parallel$			
24	20-21	0.02	2.5	0.0 8					11.	$\dagger \dagger \dagger$	† †	+++	; ;;;			المعبده .	<u>,</u>	Į.	ilt		ĦĦ	11
25	21-22	<0.01	2.1	0.0 7	71.4	3.1					$\parallel \parallel$	\prod			*	\\	*III	P]].
56	22-23	_<0.01	3.2	6.2 7										╏╏╏┇	Χþ	#:-:	18	ļķ.				<u> </u>
27.	23-24	♥.01	3.4	5.9.7							$\ \ $	111			ÑÎ	/ /- /-	ØII	8	- -	liil		
<u>38</u>	24-25 25-26	<0.01 <0.01	3.8	5.3 8					+	+++	\mathbf{H}	$\frac{1}{1}$				8123	M	\mathbb{H}	╫	╏╏	╫	l F
30	26-27	40.01	3.4	0.0					 		$\dagger \dagger \dagger$	1111	i	†††	136	(· · · · · /				†! !		
31	27-28	<0.01	5.8	3.4 8				H			† †				{	#	K K			liii		
32	28-29	€0.01	2.9	0.0	- 1										X	-//	*]]	\coprod				III
33	29-30	0.02	1.9	0.0!6							\prod	-			10	8138			77	$\parallel \parallel \parallel$	$\left \right \left \right $	╁╁
34_	30-30.9	<0.01	3,2	0.0	20.7	4.3			11	++1	$\left\{ \right\} \left\{ \right\}$	-1-1-1	╏╂╂╂	╂╂╂╂	$\widetilde{\mathbb{M}}$	· - · · · · /	*19	\prod	╂╂	╏╂╂╂	$\{\}\}$	
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35	8133-34	<0.01	1.9	0.0 2	21.0	2.8		1	#			111			 	::// :						À
36	34-35	₹0.01	2.1	0.0 7											*	8135	<u> </u>			\coprod		
<u>.</u>									\coprod	\coprod		1111			\coprod	· · · · · · · /			Щ.			.
<u> </u>									\prod		 	┧╂╏		╂┨╂╏	44	<i>H</i>	1444	$\ \ $	╟	╀┼╏	╏┼╏╂	444
200	8138-39		1 0	0.0	30 O	1 7		-	+	+H	╢		╫╫		1	#			╁╂			tl:
)/_ 8	39-40	<0.01 <0.01	1.8	16.7 6							Ħi		H++-		+;]	8140	Mi	抃				#:
39	40-41	_<0.01		11.8 7											179	120	1/8		\prod			
0	41-42	₹0.0 3	1.4	0.0					#	\coprod		!!!!			11	#:-::	f p	111				∐ ,
1	42-43_	0.01	1.8]]	\prod		111			119	-//	1	\prod		$\left\{ \left\{ \left\{ \right\} \right\} \right\}$	- -	.]]}
2	4344	*0.01	1.5						╁┼			+++	-		1	-7			M		+ 4-	
3	44-45 45-46	<0.01 <0.01	1.9	0.0 6	34.3				#		╫					8145	////	//	Π			#
5	46-47	<0.01	1.3												1	<i>Z</i> -:	N R					
6	47-48	0.65	1.4	0.0		5.1								k		: <u></u>			Ш			 -
7	48-49	<0.01	2.2	0.0	95.0	1.8			-}}-		$\{ \} \}$	4-4-1-			件	:;#.	*0 					$\ \cdot\ $
			!						╫	+++	##	111			\prod	8150	 	╂┼	╫		╂┼┼	##:
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	42 5 5 5 6										!!!					8155]	<u> </u>	!	i i i		
<u>3</u> 9	8155-56 56-57	<0.01 <0.01	1.1 2.3	0.0	1					$\left\{ \left\{ \right\} \right\}$			╏╂┼	$\{\ \cdot\ _{\cdot}\}$	+JJ		} }}		-			
Q.,	57-58	0.01	5.4	0.0 1	7				## !		111	+			1	<i>}</i> //:	*	-				1
ì	58-59	√0.01	2.2	0.0											\ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \	/	3			1111	of t	1
5	59-60	<0.01	1.8	0.0											Ϋ́¢	8160	<u> </u>				Ŋ	\prod
3	60-61	0.05	5.7	0.0	,				11		 	┞╏╏ ╬╬╬	┇┇┇ ┇┇╅╈		vμ	. \ \		1;;} {-{}-			┇┇ ┇┋╃╃╃	
4	61-62	0.02	3.6	•	ì				11	##	#	╫	 	7 I.) !	,,,,	· · //·			H	┇┇	┨┧╁┨	
) 5	62-63_ 63-64	7.2 0.01	4.8_ 7.2	4.2 9.7					11		#	+++	\mathbb{H}^{+}	Щ	1	,::::\ \	12	$\ \ $		H H	╁╁╁	$\dagger \dagger \dot{}$
7	64-65	0.02	5.1	9.8					Ti					!!!	X	8165	<i>[]</i>			1111		
3	65-66	<0.01	1.2	0.0	50.0				\prod		\prod				孙	\mathcal{H}	XIII			8	111	
€ ,	66-67	_<0.01	2.9	0.0.4					44				┃╏╏╏ ┃┪┩┿╌		3	: -//. : .			Ш	6		11.
j_	67-68	_≪0.01	2.4	0.0	50.0				-			 			幹	//	; !	-	$\ \ $	P	╽╟┼┼	.
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43	8155-56	0. 01	1.1	0.0	54.5				tiit	Hii	1111	iiii	1	1/07.33		1111	ø	1:11	Ħ;
49.		<0.01	2.3	0.0	52.2										k i i i i		6	111	
50	57-58	0.01	5.4		14.8								K	····//					
)]	58-59	€0.01	2.2	I	36.3								113		k			9	
52	59-60	<0.01	1.8		33.3					1111				(8160][]	15	\prod_{i}
53.		0.05	5.7.	1	10.5			- 1	1111			11-				4 1-1			
54.		0.02	3.6		11.1		-		 	11:1	╁╂╂╕	+++	批					1141	
55 56		7.2	4.8_7.2	4.2	8.5				††††	###	++4	44	[N]	<i>\</i>					11:
57	64-65	0.02	5.1		7.8				1111	1111	1111		Ty !	.8165				1111	
jg		<0.01	1.2	1	50.0				1111	###	1117			19:03			l o	拼	Ħ
59		_40.01	2.9	l	48.2								1133	-/]			þ		
60	67-68	<0.01	2.4_	0.0	50.0									:7/	k		Ιþ		$\prod_{i=1}^{n}$
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1	8190-91	2.1	2.7	0.0	55.6		<u> </u>				TR.			8190	ķilit		<u>a</u>		##1
2	91-92	0.24	2.8		21.4								Ŕ	<u> </u>					<u> </u>
3	92-93	0.01	2.0	4	50.0		ļ		<u>IIIi</u>				113	<i></i>	† !!!!			11111	∐'.
4	93-94	0.07	2.6	0.0	92.3	· · ·				1111	111		11.65	:://_::	1911				
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,	8200-01	9.01	7	11.6									×	<i>}</i>	//x				
-	01-02	₹0.01	1.3	0.0			ļ		$\left\{ \left\ \cdot \right\ \right\}$	[]]			11.7	:- <u>//</u> -::					
13	02-03 03-04	0.01	1.7	0.0 6.9	,	 		-	╢╫	++++	+ -	+H		[]			1111		###
	04-05	₹0.01	5.5	0.0				[]]]	H:	 	HH:	444	1413	(= 111)		-]}}}	HH:
Ţ	05-06	√0.01	1.9	0.0							†††;	- 	74	12-27	ď	ilii			1111
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	07-08	<0.01	1.4	0.0	93.0								×	····//	β.				
	08-09	_<0.01	4.2	_0•0;									×	·····/	٦				 -
1	09-10	₹0.01	4.1	0.0		•					!!		1	8210	P.		 	1111	-
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9. 3.9 0.0 97.5 1. 1.0 20.0 80.0 0.6 0.0 66.6 1.3 0.0 15.4 0.8 0.0 25.0 1.2 0.0 83.4 1.4 0.0 14.3 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8235 8330 844 845 854 854 854 854 854 854	-06
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8235 8235 8235 8235 8235 8240 8240 8240 8240 8250 8250	5.5 9.4 3.8 3.0 5.0
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8235 8235 8235 8240 8240 8240 8250	
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8235	
	8220 8215

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

		HORIZONTAL
DEPTH (ft)	SAMPLE FOOTAGE (ft)	PERMEABILITY (md)
7635-7636	1	0.01
7636-7637	1	0.01
7637-7638	1.	0.01
7638-7639	1	0.03
7639-7640	1	0.07
7640-7641	1	0.10
7641-7642	1	< 0.01
7642-7643	1	
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
/04/-/040	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 7750	•	
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

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

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	BEFORE EXAMINER STAMETS
	OIL CONSERVATION DIVISION
	MOLICANTS EXHIBIT NO. 4
į	CASE NO. 7313
	Submitted by McCoro
	Hearing Date 7 - 29-81
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CORE LABORATORIES, INC.

] Petroleum Reservoir Engineering

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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

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

DEFORE EXAMMENT STAMET OIL CONSERVATION DIVISION	S N
APPLICANTS EXHIBIT NO. 10	
CASE NO. 73.13	
Submitted by Molons	
Hearing Date <u>7-29-81</u>	and statement of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of the last of t

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	PLE YN MUNICUNIAL YO LOUNCES	SAND SAND SAND SAND	() > > C C	DENSITY	WYCMCN1C TAKUT CC7C	\$	INPUT FURMAL ALY	ב זעלאב טבריות	LONGITUDE ELEVATION	API WELL NUMBER - 30 037 01772 00

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

		,	•
DEDTH (6.)			HORIZONTAL
DEPTH (ft)	SAMPLE	FOOTAGE (ft)	PERMEABILITY (md)
7904.5-7905	·	£	
7905-7906	•	.5	0.02
7906-7907		1	0.02
7907-7908		1	< 0.01
7908-7909		1	< 0.01
7909-7910		1	0.06
7910-7911		1	0.01
7911-7911		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
7317-7310		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	J 0 01
7958-7959		1	< 0.01
7959-7960		1	< 0.01
7960-7961		1	0.01
7961-7962		1	0.01
7962-7963		1	0.02
7963-7964		1	0.01
7964-7965		1	0.01
7965-7966		1	0.01
7966-7967		1	0.01 0.01
7967-7968		1	0.05
7978-7979		1	0.01
7979-7980		1	< 0.01 < 0.01
7980-7981		1	< 0.01
7981-7982		1	0.02
7982-7983		1	0.02
7983-7984		1	0.07
			0.07
7989-7990		1	< 0.01
7990-7991		1	< 0.01
7991-7992		1	0.02
8005-8006		1	0.07
8006-8007		ī	0.01
8007-8008		1	0.01
8008-8009		ī	< 0.01
8009-8010		ī	< 0.01
aces of the second		- -	
8014-801	BEFORE EXAMINER STAMETS	15	0.28
8015-801	OIL CONSERVATION DIVISION	_ B	0.23
8016-801		1	0.54
8017-801 AR ?	LICANTS EXHIBIT NO. II	. 1	0.06
	CASE NO. 73.3		
	Submitted by LCORD		
- 11	Hearing Date 7-29-81	ĺ	
	ricaring Date 1200		
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DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
8022-8023	1	< 0.01
8023-8024	1	< 0.01
8024-8025	ī	< 0.01
8025-8026	î ,	< 0.01 < 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		0.04
8035-8036	1	0.05
8036-8037	ī	
8037-8038	i	0.07 < 0.01
8038-8039	1	
8039-8040	i	0.14
8040-8041	1	0.35
	A. Article Control Control	< <u>0.01</u>
TOTAL	62.5	3.60
Avg. $K = \frac{3.60}{62.5} = 0.058 \text{ md}$		

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 MUDCORES DIAMOND
LOCATION SEC. 33-T31N-ROW REMARKS SAMPLED BY REPRESENTATIVE OF CLIEN
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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	$\overline{1}$	0.01
7835-7836	ī	0.01
7836-7837	1	0.01
7837-7838	1	0.01
7838-7839	1	0.01
7839-7840	1	0.01
7840-7841	ī	0.01
7841-7842	1	0.01
7842-7843	, <u>î</u>	0.01
7843-7844	1	1.50
TOTAL	13	1.62

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

CONE SECRETIONS

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6990-7039. Recovered 21' blk. shale, cottom 6' sli handy.
COnc 11
          7039-7042. Core jammed in bul. Recovered 2' olk shale.
COKE #2
          7042-7045; Core jamed in bbl. necovered 31 blk anale.
00:42 //3
CORE #4
          7800-7630. Recovered 25 1/21.
                      l. shale, gry-bix, platy, ali sandy, micaceous, or coal
                          send, gry, vig, cale, sli silty, scattered mica., duse
                      3. Shale, Sh, Micaseous, Would bered sand lenses, 15% sand
                      4. sand, gry, vfg, cale, very silty, smale stringers, abdt
                          mica, once, tite...
                      6. same, 20% blk shale
                          shals and same in alternating layers, predominately shale
                      7.
                          shale, blk, sli sandy, calc, micaceous
                      9. mane, a/peurly pelecypod frags
                     10.
                     11. Same
                     12. same
                     13.. same
                     14. same, concentric fractures parallel to bedding
                     15. dimestone, buff-bra, dase, silic, crypto-kln, horizontal
                          fractures
                         shale, bl., sli sandy, micaceous
                     17. same, concentric fractures parallel to bedding
                          same, no fractures
                     18.
                     19.
                          whale and sand in alternating layers, predom. shale
                     20. Shale and make in alternating layers, predom. sand
                     21. sand, gry-an, ig, hard, dose, scattered intergranular
                         · poro
                     22. same, sli silty, w/norizontal fractures 23. same, shaley (40%), micaceous
                     24. shale, Ulk, micaceous (75%); sand (25%)
                     25. sand, gry, 12, hard, micaceous, a/abut pyrite
                         same (60%); snale (40%)
                     2ò.
```

COLE #5 7830-7831. No recovery.

CURE #6 7831-7844. Full recovery.

l. Jand, gry-wh, fg, hard noriz. True, or fair intergranular poro

2. same, a, thin shale portings, tr fair poro

3. same, no frac, tr fair poro

4. same, sli silty, tra'air poro

5: same

6. same, fair poro -

7. same, tr fair poro

8. ತಾಮಿ

y. same

11. sime, w/thin shale partings

12. same, or fair poro 13. same, shale (20%), or poro

784,-7844. Full recovery. उजारे 47

1. sand, gry-wh, fg, hard, or intergranular poro 2. sime, w/scat shale partings and horiz frac

33.00

4. Salie

ABBREVIATIONS USED IN SEPTER & STAR DESCRIPTION

4 - angular abdt - soundant bent - bentomite (itic) olk - black brn - brown calc - calcareous duse - dense fg - fine grained foss - fossiliferous frac - fractured frag - fragment(2) fx - finely crystalline glau - glauconite(ic) grn - green gry - gray horiz - horizontal lGR: - intergranular incl - inclusions

ig - large grained

is - limestone as - medium grained poro - porosity pyr - pyrite atzitic - quartzitio h - rounded SA - subangular scat - scattered sdy - sandy sh - shale silic - siliceous sli - slight Sk - subrounded ss - sandstone tr - trace V - very vert - vertical wh - white xln - crystalline

הדהע בוכצעהות שוטע

2300	46	-	7837	-7844
-01		_	1014	~ / U LLLL

13.715 19.	DEFTH	rakomandiaTY CYONAGIAIN	VET PUROLITY	YTLUCHCI LLATUT K
		•		
1	7E32	ು. ೨ 1	4.20	4.65
2	7833	3.31	2.75	3.70
. 3	7834	JU.O	4.10	4.42
4	7835	0.01	1.17	2.08
5	7836	5.01	1.47	∠.ઇ1
6	78 37	0.01	ج <u>کہ ک</u> 8	ر.50
7	7838	J.JL	` ৴.০৪	7.80
8	7839	0.01	8.50	9.30
ÿ	7840	0.01	7.20	i•≠0
10	7841	J.01	2.76	۶ ۰ 1 6
11	7842	0.01	2.65	ِ وَ رُ فِيْ
12	7843 .	0.91	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	
MUNTS EXHIBIT NO13	
CASE NO. TBIB	d
Submitted by McLore	
Hearing Date	



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

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. 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 Permezbility

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 docs not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

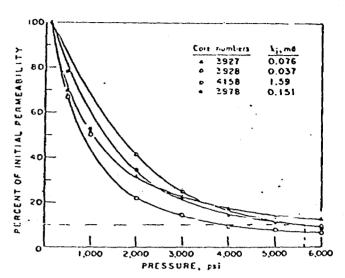


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

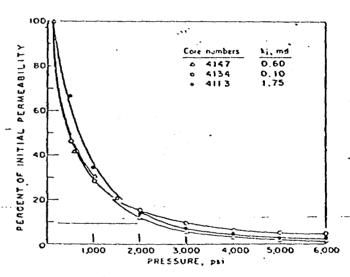


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

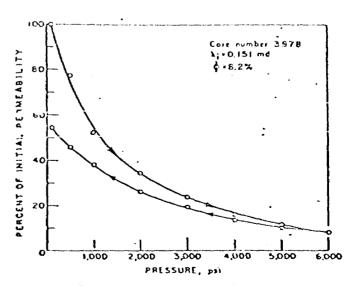


Fig. 3--Hysteresis effect at decreasing confining pressures.

TABLE 1-EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Over	burden Pies	sure (psi);		500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	kiţ			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	6.034	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.

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 rores 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 al-

though 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.

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 Pressure Number (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	6,600	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	
3578	6,000	0.013	0.009	0 004	0.0013	
4158	300	0.447	0.335	Û.Ìốb	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 Whe	εl					
8084	100	0.038	0.030	0.014	0.0042	
E084	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	300.0	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	0.617	0.013	0.005	0.0005	

[&]quot;"Slightly fractured.

finitial permeability.

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 insitu 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

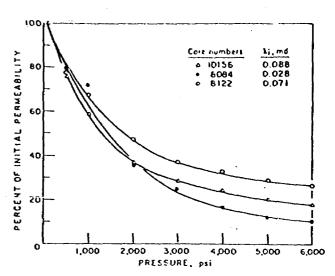


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

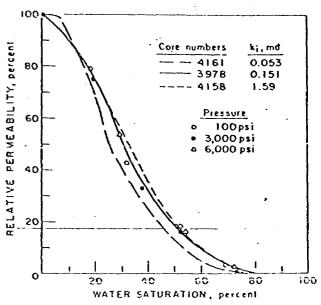


Fig. 5-Relative gas permeability of Gasbuggy cores.

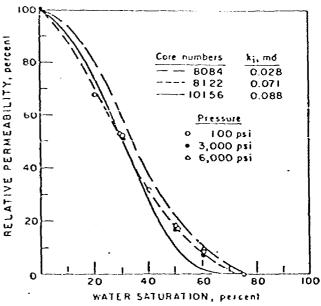


Fig. 6-Relative gas permeability of Wagon Wheel cores.

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 pressureeffect 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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- 1. Fatt, I. and Davis, T. H.: "The Reduction in Permeability with Overburden Pressure," Trans., AIME (1952) 195, 329.
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- 5. Fatt, J.: "The Effect of Overbuiden Pressure on Relative Permeability," Trans., AIME (1953) 198, 325-326.
- 6. API Recommended Proctice for Core-Analysis Procedure, API RP 40, Dellas (1960) 35.

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.

Oil CONSERVATION DIVISION

EXHIBIT NO.

CASE NO. 7313

Hearing Date 7-29-8

Entering the graph in Pigure 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

		SAMPLE FOOTAGE	LABORATORY PERMEABILITY
	WELL	TOTAL (ft.)	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 = $\frac{35.36}{286.2}$ = $\frac{0.124 \text{ md}}{200.2000}$

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

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION

APPLIANTS EXHIBIT NO. 15

CASE NO. 73 13

Submitted by Mulanto

Hearing Date 7-29-81

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
OIL CONSERVATION DIVISION
CASE NO. 1313

ROSA TIGHT GAS AREA

EXHIBIT NO. 16

Submitted by Ne Oxe > Natural P. Hearing Date 1-29-81 (P.

Natural Production Tests (Pitot Tube)

	11. 12. 13.	
	OPERATOR El Paso Natural Gas Co. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp. Northwest Pipeline Corp.	
	WELL San Juan 30-4 Unit No. 39 San Juan 30-5 Unit No. 39 San Juan 30-5 Unit No. 37 San Juan 30-5 Unit No. 49 San Juan 30-5 Unit No. 73 San Juan 30-5 Unit No. 72 San Juan 30-5 Unit No. 47 San Juan 30-5 Unit No. 47 San Juan 30-5 Unit No. 47 San Juan 30-5 Unit No. 48 San Juan 31-6 Unit No. 38 San Juan 31-6 Unit No. 36 San Juan 31-6 Unit No. 35 San Juan 31-6 Unit No. 35 San Juan 31-6 Unit No. 35	
14 WELL AVERAGE	SENW 18 30-4 SWNE 7 30-5 NESW 8 30-5 SWSW 9 30-5 SWSW 10 30-5 SWSW 10 30-5 NESW 16 30-5 NESW 17 30-5 SWNE 18 30-5 NWNE 20 30-5 NENW 2 30-6 NENE 27 31-6 NENE 35 31-6 SESE 35 31-6	
E (Excluding Well No.	TEST DEPTH 8615 7822 7870 7780 8035 7,905 7,820 7,930 7,891 7,870 7,890 7,890 8080 7,928	NATURAL PRODUCTION
ll No. 8)	DEPTH 8425 7686 7688 7683 7919 7790 7785 7794 7667 7790 7832 7806 7908	DAKOTA
423 288	(MCFPD) 527 161 666 TSTM 338 338 264 2174 128 370 241 TSTM 338 370 370	PRODUCTION RATE
2460 2525	(MCFPD) 2506 1703 3944 855 2635 2456 1209 1610* 2035 3691 2828 2557 2643 3770	PRODUCTION RATE AFTER FRAC

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

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

FOUR CORNERS GAS PRODUCERS Rosa Tight Gas Area Basin Dakota Field

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

 $(Pe^2 - Pwf^2)$ Qg = .703 k hDarcy's Law: Ug T Z ln (.61 re/rw

where:

Qg = gas flow rate - standard cubic feet per day

= permeability of formation - used average in situ value of 0.012 md from core data

= 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

= bottom hole temperature - calculated to be 667°R

= 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 2

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)
$$(3330^2 - 14.6^2)$$
 (0.020) (667) (0.88) ln (.61 1320/.17)

Qg = 39,546 SCFGPD = 39.5 MCFGPD

BEFORE EXAMINER STAMETS OIL CONSERVATION DIVISION APPUCATE AND THE TELEPOLISM CASE NO. 1313 Submitted by MeCorb Hearing Date 7-29-8 THE PERSON HAVE THE PROPERTY OF THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAVE THE PERSON HAV

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 esservoirs. 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 Posa 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 aguifer 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
ENE GY AND MINERALS DEPARTMENT
O. CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
29 July 1981

EXAMINER HEARING

IN THE MATTER OF:

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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

APPEARANCES

For the Oil Conservation Division:

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

For the Applicant:

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

and

Gary Paulson, Esq.
Amoco Production Company
17th and Broadway
Denver, Colorado 80202

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2 MR. STAMETS: The hearing will please come to order. 3 We'll call at this time Case 7317. MR. PADILLA: Application of Four Corners 5 Gas Producers Association for designation of a tight forma-6 tion, San Juan and Rio Arriba Counties, New Mexico. MR. CARR: May it please the Examiner, 9 my name is William F. Carr, with the law firm Campbell, Byrd, 10 and Black, Santa Fe, New Mexico, appearing on behalf of Four 11 Corners, and I have one witness. We would also like to enter our appearance 12 at this time for Gary Paulson, an attorney for Amoco out of 13 Denver. 14 15 MR. STAMETS: Any other appearances in 16 this case? 17 MR. KELLAHIN: If the Examiner please, 18 I'm Tom Kellahin, Santa Fe, New Mexico, appearing in associa-19 tion with Mr. Larry Pain, an attorney for Phillips Petroleum 20 Company. 21 MR. STAMETS: Any other appearances? 22 MR. PAULSON: Yes, sir, Gary Paulson 23 Amoco Production Company, appearing in association with Mr. 24 Carr. 25 We do have a supporting statement to make

2 on behalf of the application. MR. STAMETS: Does anyone else have an appearance? Any other witnesses in this case? 5 I'd like to have the witness stand and 6 be sworn at this time, please. (Witness sworn.) 10 KEVIN H. McCORD 11 being called as a witness and being duly sworn upon his oath, 12 testified as follows, to-wit: 13 14 DIRECT EXAMINATION 15 BY MR. CARR: 16 Will you state your name and place of 17 residence? 18 My name is Kevin H. McCord and I live 19 in Farmington, New Mexico. 20 By whom are you employed and in what 21 capacity? 22 I am self-employed. I'm a self-employed 23 petroleum engineer acting as a consultant for the Four Corners 24 Gas Producers Association. 25

Have you previously testified before

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2	this Commission or one of its examiners and had your creden-
3	tials as a petroleum engineer accepted and made a matter of
4	record?
5	A. Yes, I have.
6	Q. Are you familiar with the application of
7	Four Corners Producers Association in this case?
8	A. Yes, I am.
9	Q Are you familiar with the subject area?
10	A. Yes.
11	MR. CARR: Are the witness' qualifica-
12	tions acceptable?
13	MR. STAMETS: They are.
14	Q Mr. McCord, will you briefly state what
15	Four Corners Gas Producers Association seeks with this ap-
16	plication?
17	A. The Four Corners Gas Producers Associa-
18	tion is applying for a portion of the Basin Dakota gas field
19	to be designated as a tight formation under Section 107 of the
20	Natural Gas Policy Act of 1978.
21	The proposed Rosa tight gas area is
22	located in the northeastern portion of the San Juan Basin.
23	The area is approximately 25 miles northeast of the town of
24	Bloomfield in northwestern New Mexico, and covers portions of
25	Rio Arriba and San Juan Counties.

I.	'
2	Q. Have you prepared certain exhibits for
3	introduction in this case?
4	A. I have.
5	Q Have each of these exhibits previously
6	been submitted to the Oil Conservation Division and the
7	United States Geological Survey with a statement of the means
8	and purpose of each, as is required by Oil Conservation Divi
9	sion rules?
0	A. Yes, they have.
1	Q Will you please refer to what has been
2	marked for identification as Applicant's Exhibit Number One
3	and explain to Mr. Stamets what this is and what it shows?
4	A. Exhibit Number One displays the Rosa
5	tight gas area on a map of the Dakota reservoir in the San
6	Juan Basin. The Rosa area includes approximately 270,260
7	acres in Townships 30 and 31 North, Ranges 2 through 7 West.
8	Q Will you now refer to Exhibit Two and
9	review this for the Examiner?
0	A. Exhibit Number Two is a Dakota formatio
1	completion and production map of the proposed Rosa tight gas
2	area. The production figures presented for each producing
3	well are initial potential, date of initial potential, avera
4	daily production for 1980, and January 1, 1981 cumulative
5	production of gas and oil.

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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.

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

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

1 2 characteristics than the remainder of the area. Wells in the 3 remaining sections of the Rosa area would be expected to have the same or poorer log characteristics than this type log. How is the Dakota formation defined by the Oil Conservation Division? The State of New Mexico has defined the 8 Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn limestone and extend to a point 10 400 feet below the base of the Greenhorn. The formations 11 covered in this 400 feet are the Graneros Shale, Dakota Sand-12 stone, and Morrison formations. The Dakota formation is productive in 13 this area while the Morrison formation is generally water-14 bearing. Sands in the Graneros Shale are not adequately 15 16 developed in this area to be productive. 17 Mr. McCord, what is the average depth 18 of the Dakota formation in the area which is governed by this 19 application? 20 7950 feet. 21 And what is the gross thickness of the 22 formation? 23 Approximately 250 feet. 24 Could you generally describe the geolo-

gical characteristics of the Dakota?

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2 It's generally, let's see here, the Dakota 3 consists generally of barrier beach deposits about 40 to 60 feet thick. This is the Upper Dakota. Composed of fine 5 grained, quartz rich sandstones characterized by an increase 6 in grain size upward and low angle crossbedding. 7 The next highest unit is transitional 8 between fluvial and marine sedimentation containing dark 9 carbonaceous shales, thin mudstones, siltstones, and sandstones. 10 This unit represented a lagoonal type environment. 11 The basal Dakota was deposited by a 12 system of meandering streams creating deposits of carbonaceous 13 shales, thin coal seams, siltstones, and thin channel sand-14 stones. 15 Will you now refer to what has been 16 marked Applicant's Five and Six and explain what these are 17 and what they show? 18 Exhibit Numbers Five and Six are log 19 cross sections through the Rosa area showing the continuity 20 of the Dakota formation using the base of the Greenhorn form-21 ation for a datum line. 22 Now, Mr. McCord, when I look at your

east side of the subject area?

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Exhibit Number Two, is there any control in the Dakota on the

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

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2	very sparse drilling in that area. Only one well was drilled
3	and that would be in Section or Township 30 North, Range
4	3 West, Section 34. A Dakota well was drilled by Sunray DX
5	Oil Company, Jicarilla Tribal No. 1, in September of '64.
6	It was drilled and abandoned.
7	Other than that there is no control to
8	the east part of the area.
9	Q In your opinion is the Dakota continuous
10	across the basin?
11	A. Yes, it is.
12	What is the porosity range within the
13	area governed by the application?
14	A. Overall the Dakota sand has a porosity
15	range of from 1/2 percent to 11-1/2 percent in the Rosa area,
16	with the average pay porosity being in the neighborhood of
17	4 to 6 percent.
18	Q Is the in situ permeability cutoff in
19	the Rosa tight gas area less than .01 millidarcy?
20	A. Yes, it is. The formation is dependent
21	upon stimulation techniques to be commercially productive.
22	And have you calculated permeability for
23	the area?
24	A Yes, I have.
25	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.

Mill you now refer to and identify what you have marked Applicant's Exhibit Thirteen?

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. Will you now refer to your Exhibit Number Fifteen and explain this exhibit? 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. Mr. McCord, can gas be produced in com-

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mercial quantities from the formation in the subject area

without stimulation?

No, it cannot.

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

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the Oil Conservation Division rules?

A 336 Mcf of gas per day.

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Q Have you obtained stabilized unstimulated

gas production rates for Dakota wells in the area?

...

to the reserve pit.

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

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.

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

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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.

Have you calculated the unstimulated gas

flow rate using the in situ permeability value of .012 millidarcies? 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

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.

situ permeability of 0.012 millidarcy for the Rosa area.

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

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.

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well?

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

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.

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.

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.

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.

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

1	23
2	all the specifications required as stated above and should
3	be designated a tight formation in the Basin Dakota Pool under
4	Section 107 of the Natural Cas Policy Act of 1978.
5	Mr. McCord, has this area been approved
6	for infill drilling?
7	A. Yes, it has in May of 1979.
8	Q. And that was by Commission Order R-1670-V?
9	A. Yes, I believe so.
10	Q Have any infill wells been drilled in
11	the subject area?
12	A. There have been a few infill wells
13	drilled in this area after I have gathered all the data for
14	this report. I'll point those out. They are both John Schalk
15	wells. One would be in the southeast
16	MR. STAMETS: Start out with the township
17	and range.
18	A. Sure.
19	MR. STAMETS: It makes it a little easier
20	to find.
21	A. Okay, 30, 30 North, 5 West, Section 2,
22	southeast quarter.
23	The other well being in 30 North, 5 West,
24	Section 12, I believe the northeast quarter.
25	These are recent wells that have been

1	24
2	drilled. My information on this map is May of 1981, so these
3	are recent wells and it's my understanding have not been com-
4	pleted at this time.
5	Q. How would you characterize the develop-
6	ment of the subject area on the original 320-acre spacing?
7	A. Very, very sparse development under 320
8	acres. I believe I calculated under the existing acreage 53
9	producers. This is only 6 percent of our 320-acre spacing,
10	and to my knowledge these two Schalk wells mentioned are the
11	only two infill wells that have been attempted in the area.
12	I believe that might have had something to do with that man's
13	holdings in the area more than all the economic criteria
14	involved.
15	Q. Mr. McCord, in your opinion will further
16	development of the subject area depend upon approval of this
17	application and the resulting incentive price?
18	A. I think, yes, to be adequately developed
19	this area will need the 107 price to make it economically
20	feasible.
21	will you please refer to and identify
22	what has been marked as Applicant's Exhibit Eighteen?
23	A. Exhibit Eighteen is a written text ex-
24	plaining each of the exhibits I have just presented.
25	ρ And this text was submitted with the

45 Va a

2 exhibits to the Commission and USGS? 3	1			25
Q Were Exhibits One through Eighteen prepared by you or have you reviewal 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.	2	exhibits to the Commis	sion and USGS?	
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11 A. Yes. 12 Q. Will granting this application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights? 15 A. Yes, it will. 16 MR. CARR: At this time, Mr. Stamets, we would offer into evidence Applicant's Exhibits One through Eighteen. 19 MR. STAMETS: These exhibits will be admitted. 20 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.	9	plication result in th	ne production of gas that otherwise	woul
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21 MR. CARR: Mr. Stamets, I've been asked 22 to direct certain questions to Mr. McCord on behalf of the 23 USGS and I'll be happy to do that now or at a later time, 24 whenever you desire.	19	1	MR. STAMETS: These exhibits will b	е
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.	20	admitted.		
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whenever you desire.	22	to direct certain que	stions to Mr. McCord on behalf of t	ће
whelever And departs.	23	USGS and I'll be happ	y to do that now or at a later time	,
MR. STAMETS: Well, why don't you just	24	whenever you desire.		
	25		MR. STAMETS: Well, why don't you j	ust

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26 go ahead and do that now, Mr. Carr, and then we'll get that 2 part out of the way. 3 Mr. McCord, what is the basis for the 4 boundaries of the proposed tight gas sand area designation, 5 and is this based on geologic and/or engineering parameters? 6 The area studied, and I'd like to point out is just an area of study, I'm not trying to say that areas 8 outside are not tight gas areas, it was assigned to me by the 9 Four Corners Gas Producers Association. 10 It is my feeling that it is not based on 11 either geologic or engineering parameters, mainly on the 12 rights of the Association. 13 Could you provide a structure Isopach 14 15 insert map for the Dakota for the Rosa tight gas area? It would be possible to supply a structure 16 17 Isopach map, although I do not believe that this would show 18 any more information than what cumulative production is shown 19 on Figure Two. I believe this indicates that the well, the Rosa area is definitely not a very prolific area, and because 20 21 of that I do not believe this information would be helpful, 22 but if requested, we could supply this. 23 Now, Mr. McCord, the type log for the Rosa Unit No. 68 Well, which is used as your Exhibit Number 24 25 Four, indicates that four separate zones were perforated for

2 production. In reviewing the wells presented and the two 3 cross sections, being Exhibits Number Five and Six, in some wells more than four zones were perforated. 5 The question is, is this application asking for all zones in the Dakota to be designated as a 6 7 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. 10 The question is, are you asking for all 11 of the zones in the Dakota to be designated tight formations? The Four Corners Gas Producers 12 requested that the entire Dakota section as defined 400 feet 13 below the base of the Greenhorn be designated as a tight 14 15 formation. Is this application asking for a tight 16 17 sand designation for infill locations within the Rosa tight gas area, and there are certain examples given here. First, 18 19 in Township 30 North, Range 5 West, Section 9, there are apparently two infill locations. Is it the request of the ap-20 plicant that these be included in the tight sand designation? 21 22 Yes, it is. 23 24

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

> Yes, those also. A.

1	28
2	Q. In Township
3	MR. STAMETS: What was the last section?
4	MR. CARR: Section 20. All of this first
5	group, they are all in Township 30 North, Range 5 West.
6	MR. STAMETS: And there are two in there
7	or just one?
8	MR. CARR: Two, according to the question
9	MR. STAMETS: Infill locations in Section
10	9 and 20
11	MR. CARR: And 10.
12	MR. STAMETS: And 10. Let me get 10
13	marked on my exhibit, please.
14	MR. CARR: All right. Now in Township
15	31 North, Range 5 West, one location in Section 8.
16	A. Okay. I believe there should be two
17	locations in Section 8. I do not have an infill well in that
18	location, or in that section. I believe that should be two
19	locations, and yes, we are asking for that also.
20	Ω And, again, two locations in Section 11
21	and in Section 17?
22	A, Yes,
23	Q And now in Township 31 North, Range 6
24	West, two locations in Section 27 and two locations in Section
25	35.

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29 1 2 Yes, we ask that these be part of the 3 application as well. MR. STAMETS: What was the second section, please? MR. CARR: 35. 7 So you are asking that all infill locations within the Rosa area be included within the tight sand designation? That is correct. 10 11 Mr. McCord, I direct your attention now Q. 12 to Exhibit Number Three, and it indicated that 12 Dakota wells were drilled in 1980, and 9 Dakota wells were drilled in 1981, 13 14 all at current 103 prices. 15 Is it no longer economical to drill wells such as those drilled in 1980 and '81 under 103 prices? 16 17 Yes, it would still be economical to drill some of these newer wells that were drilled in 1980 and 18 1981 under 103 prices if there were -- existed any good pro-19 ducing characteristics such as exhibits by those wells. As 20 to the current time there are not any of this type of location 21 available. Therefor, to continue to drill wells in this area 22 the 107 price would be necessary to -- to substantially com-23 24 plete the area.

Is it your answer that if there were

1 30 2 comparable locations in the Rosa area that the wells could 3 be drilled at 103 prices? Yes, it's my feeling they could. At this time, based on your study, you 6 do not believe there are comparable locations? 7 I don't believe that, no. Is the 107 price necessary to have an 9 economical well that would be similar in production potential 10 to those drilled in 1980 and 1981? 11 Yes, it would be necessary because as we 12 stated before there are no more wells of the calibre drilled **i3** of the ones in 1980 and '81 with -- with that calibre for 14 103 prices; therefor, the 107 is needed. 15 Also, there is no more drilling, the 16 drilling plan for 1981 has been discontinued in this area 17 because of the marginal economics. 18 Mr. McCord, could you provide economic data as to the rate of return on -- showing comparison of 19 20 several of the 21 wells that were drilled in 1980 and 1981, 21 using the 103 price and contrasting that with the 107 price? 22 Yes, it is possible to provide this 23 economic data, although in the instance of this area, there 24 is mainly developed on 320 acres, acre spacing, and it's my understanding that economics are not required of 320-acre

1 31 2 spacing in the Dakota. 3 Of the 21 wells that were drilled in 1980 4 and '81, do you know if the economics on these wells made 5 them attractive prospects? 6 Yes, in some of the wells they were at-7 tractive prospects under 103 prices, but it is my understanding ģ that some of these wells drilled in '80 and '81 were demand 9 wells. Also, some had marginal 103 economics. This is exemp-10 lified by the fact that the drilling in 1981 has been discon-11 tinued for the area because of the low profitability of these 12 wells. 13 MR. CARR: I have no further questions 14 of Mr. McCord. 15 MR. STAMETS: Are there other questions 16 of the witness? Mr. Chavez? **17** 18 QUESTIONS BY MR. CHAVEZ: 19 How many unspud Dakota locations or noncompleted Dakota wells are there in this area at this time? 20 Okay, Mr. Chavez, I have them marked 21 on my map. Once again, the map is dated as of 5 of 81, so 22 23 there have been some wells drilled since then. 24 In Township 31 North, Range 6 West, Section 8, Rosa No. 88, and that's in the south -- excuse me, 25

1	32
2	the northwest quarter.
3	Q. Has it been completed or just spud?
4	A. To my knowledge it's either I don't
5	have the information as to at this time what stage of prog
6	ress it's in. It has been staked and is a possible location
7	for a future well. That's really the only thing I'm sure of.
8	That's what I have marked on the map.
9	Also, in 31 North, 6 West, Section 14,
10	in the northeast quarter, the Amoco Rosa 67. It's my under-
11	standing that this well is dry in the Dakota and Amoco is
12	possibly going to recomplete in the Mesaverde or PC in this
13	well.
14	All right, in 31 North, 5 West, Section
15	20, the northeast one quarter, the Rosa No. 85.
16	In that same township and range, Section
17	33, southwest quarter, the Rosa No. 77.
18	In 31 North, 4 West, Section 7, the
19	northeast quarter, Mitchell, the Rosa No. 81.
20	In Section 9 of that same township,
21	southwest quarter, the Rosa 82 by Mitchell.
22	Section 12, in the northwest quarter,
23	the Amoco Rosa No. 87.
24	Section 15, northeast quarter, Mitchell
25	Rosa No. 83.
i	

1	33
2	Section 23, the northeast, Rosa No. 84.
3	That's all for that township.
4	Q These are staked but not completed wells
5	A. The Mitchell wells I do know about. The
6	have all been drilled. Only one well has been perforated and
7	fraced and it is testing water at this time; no commercial
8	gas production.
9	The other three wells have not been com-
10	pleted at this time.
11	All right, Township 30 North, 4 West,
12	Section 13, Southland, the Simms Federal No. 1. That's the
13	southeast quarter. This is drilled due to lease expiration
14	date.
15	Okay, in 30 North, 5 West, I have the
16	two Schalk infill locations, the 54-1E in Section 2, and the
17	57-lE in Section 12.
18	In Section 5, San Juan 30-5 Unit No. 79,
19	in the northeast quarter.
20	Section 5, the southwest quarter, the
21	30-5 Unit No. 50.
22	Section 23, the southwest quarter, the
23	30-5 Unit No. 83.
24	Section 25, the 30-5 Unit No. 82 in the
25	northwest quarter.

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2	Q. Section what, I'm sorry?
3	A. 25. No. 82.
4	Q. What was that, I'm sorry?
5	A. That's the 30-5 Unit No. 82, the northwes
6	quarter of 25, 30-5, okay?
7	Q. Okay.
8	A Section 27, the southwest quarter, 30-5
9	Unit No. 81, and Section 36, the northeast quarter, the 30-5
10	Unit No. 77.
11	That is all the wells I have that are
12	staked in this area as of this time.
13	Ω Is the drilling of these wells pending
14	the outcome of this hearing? Or is it just pending rig
15	availability?
16	A I cannot tell you the actual answer to
17	that. I don't know what the future plans on these wells, if
18	any of them have been completed. I know some of them have
19	been drilled but I would not be able to separate each one
20	out. I've just picked them up through PI as possible location
21	in this area. I do not know the status of them all.
22	MR. CHAVEZ: That's all the questions
23	I have.
24	MR. STAMETS: Are there other questions
25	of the witness? Mr. Padilla?

35 2 CROSS EXAMINATION 3 BY MR. PADILLA: Mr. McCord, you testified about comparable 5 locations. What do you mean by a comparable location? Does that mean -- I think it would mean that that's a good location. 7 Are you saying that in this area you've run out of good locations now? 9 Yes. In my talks with Phillips Petroleum 10 Company, who is mostly in this 30-5 Unit, they have drilled 11 most of these newer wells and from talking with these people, their feeling is that -- that all of their good drilling 12 13 locations have been used up. 14 What have they based their justification 15 for --To tell you the truth, I couldn't answer 16 17 That's just information they supplied to me. that for you. 18 And that's the same thing for the same calibre, same calibre, quote, same calibre of location, is 19 20 that the same thing? 21 Yes. Yes. A.

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are for drilling Dakota wells in this area?

going to differ for any large company you're talking about,

Can you tell me what marginal economics

Well, of course, Mr. Padilla, that's

Wouldn't you have to apply the dollar

1 2 and if I said what marginal economics were, one company would 3 call it good, one company would probably call it bad. But I would say anything greater than a 5 3-year payout would be considered pretty marginal to be drilled. You just need a greater rate of return, greater return on your 7 money than tying it up for that great period of time. That's pretty rough, but once again, 9 each company is going to have a different opinion of that 10 same question. 11 Well, how much does it cost to drill one 12 of these wells? 13 On information supplied by Amoco, appro-14 ximately \$800,000 to drill and complete these wells, and ap-15 proximately 20 percent of that goes to the stimulation costs. 16 So it's a considerable amount. 17 How much revenue would, say, a Section 18 103 price, can you get from a -- one of these wells located, 19 say, in 30 North, 5 West? The newer wells. 20 Okay. I'd come up with an average 21 ultimate production of .65 Bcf throughout the entire area. 22 It's going to be, I would -- I would estimate that is a pretty 23 good average for a 30-5 Unit. The actual dollars involved 24 that that comes out to, I haven't calculated.

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amount in order to determine whether or not you should get the incentive price?

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.

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

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.

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

1 38 2 of that one well that I mentioned on there. 3 No wells to the Dakota, that is -- that is correct. This would be an area that the 107 prices would 5 virtually be a must for the exploration of. Obviously, no 6 one has thought under 103 prices this area is worth prospecting. 7 The 107 would -- would encourage drilling of wells in this 8 area. 9 Is this -- is this area unitized cur-10 rently under -- do you know? 11 I don't believe it's under a unit agreement, not the farther east. Most of the -- most of the newer 12 13 wells are under existing units. 14 Is this east half area drilled in shallower 15 formations? 16 It might possibly be but I don't have 17 that information. I've just concentrated on Dakota wells. To my knowledge, if so, there would be very, very few wells. 18 19 You don't know whether there are any 20 Pictured Cliffs wells, Pictured Cliff wells at all in this 21 area? Not offhand I don't. I would have to 22 check, check my PI cards to see if any were drilled. 23 24 MR. PADILLA: I believe that's all I have, Mr. Examiner.

BY MR. STAMETS:

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.

CROSS EXAMINATION

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.

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

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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.

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

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.

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?

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

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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

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2	this Commission and also by the FERC as it reviews your re-
3	commendations.
4	Thank you very much.
.5	MR. STAMETS: Are there any other state-
6	ments at this time?
7	Go off the record a second.
8	
9	(Thereupon discussion was
10	had off the record.)
11	
12	Is there anything further in this case
13	today?
14	This case, then, will be continued to
15	the August 26th Examiner Hearing.
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17	(Hearing concluded.)
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CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREPY 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.

Jacky W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 73/

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 develop- ment in a west-east direction.
6	Cross Section B-B'	Show Dakota formation develop- ment 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

ROSA TIGHT GAS AREA WELLS

EXHIBIT NO. 3					ďĬ		CUMULATIVE
COMPANY	WELL NAME	LOCATION	DAKOTA DEPTH	IP DATE	GAS/OIL MCFPD/BOPD	1980 PROD. MCFPD/BOPD	01-01-81 BCF/BO
Sunray DX Oil Co.	#1 Jicarilla Tribal	NW/NW 34 30-3	8213	09/64	D&A	<u> </u>	!
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/WW 18 30-4	8425	02/81	2506/0	New Well	<u> </u>
Coastline Petroleum	1 Schalk-76	SW/NW 25 30-4	8675	02/75	D&A	3	
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	ïS	.186/0
Northwest Pipeline Corp.	39 San Juan 30-5 Unit	SW/NE 7 30-5	7686	07/75	1703/0	57/0	.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	ļ
Northwest Pipeline Corp.	49 San Juan 30-5 Unit	SW/SW 9 30-5	7683	12/80	855/0	New Well	ļ
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	1
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
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COMPANY Northwest Pipeline Corp. Northwest Pipeline Corp.	WELL NAME 38 San Juan 30-5 Unit 6 San Juan 30-5 Unit	LOCATION SW/NE 18 30-5 SW/SW 19 30-5	DAKOTA DEPTH 7667 7607	1P DATE 06/80 03/56	GAS/OIL MCFPD/BOPD 2035/0 P&A	1980 PROD. MCFPD/BOPD New Well	CUMULATIVE 01-01-81 BCF/30
	San Juan 30-5 San Juan 30-5	SW/SW 19 30-5 NW/NE 20 30-5	7607 7790	03/56 C1/80	P&A 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 & Michols	12 NE Bianco Unit	SW/NE 18 30-7	7590	06/60	P&A Dakota (M7 Compl.)	1	
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.)	1	
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		<u> </u>
Northwest Pipeline Corp.	Rosa Unit #53	NW/NE 8 31-5	7900	03/70	1.043/0	126/0	.668/0
Northwest Pipeline Corp.	Rosa Unit #80	NE/SW 8 31-5	7845	03/81	2155/0	New Well	<u> </u>

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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	:1/77	342/0	82/0	:106/0
Northwest Pipeline Corp.	Rosa Unit #64	NE/NE 29 31-5	7950	1.0/78	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	IS	.029/0
Amoco Production Co.	Rosa Unit 35-X	NE/SW 5 31-6	7822	10/59	D&A Dak. MV Comp.	1	-
Amoco Production Co.	Rosa Unit #36	SE/NE 11 31-6	7955	12/59	P&A MV Comp.	;	{ { 1
Amoco Production Co.	Rosa Unit #1	SW/SE 11 31-6	7865	09/52	560/0 (P&A)		

Northwest Pipeline Corp.

Amoco Production Co.

Rosa Unit #69

79 San Juan 31-6 Unit

NE/SW 22 31-6

7757

03/81

1858/0

New Well

NW/NW 16 31-6

7918

09/80

P&A

Rosa Unit #66

NW/SW 13 31-6

7957

08/78

4427/0

245/0

.928/0

Northwest Pipeline Corp.

СОМРАНУ	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 31-0	7806	03/81	2557/0	New Well	ł
Northwest Pipeline Corp.	24 San Juan 31-6 Unit	NE/SW 27 31-6	7939	12/73	1341/0	IS	.269/0
Northwest Pipeline Corp.	16 San Juan 31-6 Unit	SE/SW 33 31-6	7895	07/59	1783/0	ıs	.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	f f
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		ł
Blackwood & Nichols	56 NE Blanco Unit	NE/NE 34 31-7	7660	1.1/58	2839/0	30/0	.417/0
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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

	DAKOTA FORMATION CORE DATA	
DEPTH (ft)	SAMDIE FOOTAGE (64)	HORIZONTAL
	SAMPLE FOOTAGE (ft)	PERMEABILITY (md)
7650-7651	1	2 22
7651-7652	1	0.01
7652-7653	1	0.01
7653-7654		0.01
7654-7655	. 1	0.02
7655-7656	1	0.01
7033 7030	_ 1	0.02
7658-7659	1	0.02
7661-7662	1	0.03
7662-7663	$\overline{1}$	0.03 0.02
7667-7668	1	0.02
7669-7670		
7670~7671	$\cdot \frac{1}{1}$	0.01
7070-7071	1	0.02
7688-7689	1	0.01
7689-7690	ī	0.01
7690-7691	1	0.01
7691-7692	1	0.60
7692-7693	1	0.01
7032 7033	1	0.01
7694-7695	· 1	0.02
7696-7697	1 .	0.25
7697-7698	1	0.25
	-	0.01
7707-7708	1	0.01
7708-7709	1	0.02
7709-7710	1	0.03
7719-7720	_	
7720-7721	1	0.01
	1	1.51
7721-7722	1	0.07
7722-7723	1	0.25
7723-7724	1	0.10
77247725	1	0.01
7727-7728	1	
7728-7729	1,	0.02
7729-7730	1	0.04
7730-7731	1	0.02
7731-7732	1	0.01
7732-7733	1	0.04
	1	0.02
7733-7734	1	0.66
7769-7770	1	0.01
7770-7771	1	0.04
7771-7772		0.03
=	1	0.03
7773-7774	1	0.01
7774~7775	1	
7775-7776	î	0.01
7776-7777	1	0.02
7777-7778		1.44
7778-7779	1	0.11
	1	0.10
7779-7780	1	6.21
7780-7781	1	0.13
		-

DEDMII (6.)		HORIZONTAL
PEPTH (ft)	SAMPLE 'FOOTAGE (ft)	PERMEABILITY (md)
7781-7782	1	0.10
7782-7783	1	0.10
77837784	1	0.01
7784-7785	1	0.03
7785-7786	1	0.03
7786-7787	1	0.09
7787-7788	1	0.02
	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
77967797		
7797-7798	1	0.18
7798-7799	1	0.61
		0.34
TOTAL	65	9.07
Avg. $K = \frac{9.07}{65} = 0.140$	md.	

CHEMICAL & GEOLOGICAL LABORY ORIES Farmington

CORE ANALYSIS REPORT

ompany El Paso Natural Gas Company
Vell No. San Juan 30-5 #27-20

ield Wildcat Bornation Dakota

Tounty Rio Arriba Depths 7649' - 7799'
Late New Mexico Drilling Fluid Water Base Mud

C-Crack * Permeability probably LEGEND S--Shight
F-Fracture caused by existing NF--No Fracture V-Vertical Shalle interlaminations-Insufficient Sample

		shale int		1	 				
SAMPLE NO.	LEGEND	DEPIH, FEET	POROSITY POROSITY	MILLION MORIZONTAL	SATUR	TOTAL WATER	CONNATE -	MUD ACID	IS %
		Core No.	1 76 ¹ +	9 - 7710					-
1 2 3 4 5 6	VF NF VF VF VF VF	7650-51 7651-52 7652-53 7653-54 7654-55 7655-56	7.7 8.7 6.7 7.7 8.6	0.01 0.01 0.01 0.02 0.01 0.02	Trace Trace Trace Trace O	27.6 16.7 12.2 12.4 21.2 15.8			-
7	VF .	7658-59	8.8	0.02	Trace	12.4			i i
8 9	VHF VF	7661-62 7662-63	10.2 9.6	0.03	0	15.2 19.2			1
10	VHF	7667-68	10.0	0.02	Trace	20.5			
11 12	VHF VHF	7669-70 7670-71	6.5 7.9	0.01	Trace	15.4 20.6			
13 14 15 16 17	HF HF HF HF VHF	7688-89 7689-90 7690-91 7691-92 7692-93	4.9 5.0 5.7 7.8	0.01 0.01 0.60* 0.01 0.01	Trace Trace Trace Trace Trace	26.1 24.2 35.9 94.7			
18	NF	7694-95	9.3	0.02	Trace	14.2	200		•
19 20	HF NF	7696-97 7697-98	11.4	0.25* 0.01	0	27.7 18.6			•
21	VHF	7701-02 ^{(*}	2.6	0.01	i o	62.3			:
22 23 24	VHF VHF VHF	7707-03 7708-09 7709-10	2.0 6.1 5.9	0.01 0.02 0.03	0 C Trace	14.5 16.0 33.9			

c-coack * Permeability probably recent P-Fricture caused by existing NF-Ne Fractive O-Open shale interlaminations in the floor Sample

S--Slight St--Stair, V--Vertical Va--Vugs

				,						!
NO.	LEGEND	DEPIH, FEET	POROSITY PORESPACE	HILLIO HILLIO HATHORISON		HONE FACE	TIO 3	CONNAIS WATER	MI'S ACID	IS SA ACID
		Core No.	2 771) - 7719	Recov	erea 91			•	
		No sampl	es ana	Lyzed						
		Core No.	3 771	7727	Recov	ered 6½				
25 26 27 28 29 30	VIE HE HE HE VHE	7719-20 7720-21 7721-22 7722-23 7723-24 7724-25	3232456	0.01 1.51* 0.07 0.25* 0.10* 0.01	\	000000	30.3 60.7 33.8 60.8 51.6 38.5			
	·	Core No.	¹ ÷ 7727	7 - 7738	Recove	red lo		1		-
31 32 33 34 35 36 37	VHF VHF VHF VHF HF HF	7727-28 7728-29 7729-30 7730-31 7731-32 7732-33 7733-31	305130000000000000000000000000000000000	0.02 0.04 0.02 0.01 0.04 0.02 0.66*		0 0 0 0 0 0	16.0 11.3 11.3 12.2 13.9 12.0 11.0			·
		Core No.	5 7738	- 7799	Recove	red 61'				
38 39 40 41	RF NF NF NF		10.8 10.5 7.7	0.04 0.04 0.03 0.03		0000	39.2 45.4 47.1 38.4	41.5		
2345678901 2345678901	· XFFFFINKUNFFHENKUNKUNFF WELVENKUNKUNFENKUNKUNKUN WELVENKUNKUNKUN WELVENKUNKUNKUNKUN WELVENKUNKUNKUNKUNKUNKUN WELVENKUNKUNKUNKUNKUNKUNKUNKUNKUNKUNKUNKUNKUN	7772-73 7773-74 7773-74 7775-76 7775-76 7775-79 7775-79 7775-30 7761-62 7761-62 7785-36 7785-36 7785-36 7785-36 7785-36 7785-36 7785-36 7785-39 7790-31 7791-92 7792-93	5.9 5.9	mple ta 0.01 0.01 0.02 1.4* 0.10 0.13 0.03 0.03 0.05 0.05 0.05 0.05 0.05 0.05 0.05 0.03		Trace Trace Trace Trace Trace Trace Trace Trace Trace O O O O O O O O O O O O O O O O O O O	2.1.2633.9.3.16.73.300.002.13 985.933.704.63.300.002.13 985.933.704.63.300.002.13	44.1 42.0		

El Paso Natural das Company San Juan 30-5 #27-20 Windows Rio Arriba County, New Mexico

--Crack | LEGIND | S-Elight |
--Fracture | NF--No-Practure | St--Stam |
--Open | IS | Irea ffice at Sample | Va-Verse

SAMPL NO.	FEDEND		FIFETIVE FORGULTY FORESPACE	PEHME MILL I HORIZONTAL	Adicity	SATE	L C PORE SPACE	CONNAIL	\$0	LUNILITY
		Core No.	5 con	inued	VEHTICAL	HESTOUAL OF	L TOTAL WATER	V. ATER	ACID	ACID
62 63 64 65 66 67	VF VF NF NF NF	7793-94 7794-95 7795-96 7796-97 7797-98 7798-99	803544 548099	0,02 0,01 -0.05 0,18 0,61 0,31		O C O Trace Trace	39.1 52.3 49.9 51.7 52.1 53.2			
67	NF	7798-99	9.14	0.31,		Trace	53.2	46.2		
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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
81408141	1	0.01
8141-8142	1	0.01
8142-8143	Î.	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

DEPTH (ft)	SAMPLE FOOTAGE (ft)	HORIZONTAL PERMEABILITY (md)
	diament (it)	TERMERBILITI (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. $\frac{11.66}{87.7} = 0.133 \text{ md}$

Petroleum Reservoir Engineering

COMPANY.	EL PASO MATURAL GAS COMPA'N	DATE ON	8/30/59	FILE NO. RP-3-1065
	EAN JUAN 30-5 No. 28-23 - X	DATE OFF	9/8/59	ENGRS. ENGLISH
FIELD	BLANCO MESA VERSE SAKOTA WILDCAT	FORMATION.	DAKOTA	ELEV. 6753 DF
COUNTY	RIO ARRIBA STATE N.MEXICO	DRLG. FLD.	OIL EMULSION	CORES DIAMOND
LOCATION	SEC23 T3CN R5W	REMARKS	SAMPLED BY CLI	INT
	SAND LIMESTONE COI	NGLOMERATE 2	. сн	T = 193
		VERTICAL PRACTURE		
	these analyses, aumono or interpretations are based on abservation	s and material supplied by the i	tent to whom lend for whose exstusive e	nd configuration

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SAMPLE	DEPTH FEET	PERM.	POROS11 V	SATUR	DUAL PATION E SPACE TOTAL	EOYLE'S LAW POROSITY	PROD			1	ISITY	X 20		· ·	,	0		i*ERC	ATUR ENT		SPA.	
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3	77 -7 8 78 -7 9	<0.01 <0.01	2.8		78.6	·					+++							报	\prod		\prod	{] } :
5	79-80	<0.01 <0.01	2.5 7.6		48.0 19.8				111			++++		<u> </u>	808	<u>}</u>	×				+	7
6_7	80-81_ 81-82	_ €0.01 _ €0.01	7.0	1	21.4								111								7	Ę
8	82-83	0.01	4.5	1	33 . 4				 	++++				X							9	
9 10	83-84 84-85	<0.01 <0.01	5.5		20.0) · · · ·		-11:		 	+++		Y.
11	85-86	0.01	2.4		50.0	1								∐j¥,	:3,	55.	\ <u>`</u>				\parallel	
12	8090-91	<0.01	2.2	0 1	81.8										1379	;o \	\ <u>\</u>					11
13	91-92	<0.01	Į.	13.5										× (//×/				+ - - - - - - - - - - - - - - - - - -	
14 !5	92 - 93	√0,01 √0.01	5.7	1	87.7									KIIC) 		þ				111.	
16	94-95	40.01	4.2	4.7	90.5 88.4					<u>: L.</u>	411		11:1	I R	1303) 5 }					11	
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	55 51	17-18	€0.01	1.1	18.2 54.6						11/1		1	4	Ш
	23	18-19	<0.01 <0.01	2.5	0.0 24.0 5.9 70.6	3.6 4.8			1	111111	30 81 3				
	24	20-21	0.02	2.5	0.0 80.1	3.6					¥4.—·		KIIII		
	25	21-22	₹0.01	2.1	0.0 71.4	3.1							9		
_	.26 .37	22-23	<0.01 <0.01	3.2	6.2 74.9 5.9 76.5							. 12	إ		
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	:	74-27	0.01	~ • 1	0.0 70.2	4.0					813				<u> </u>
	37_	8138-39	<0.01	1.8	0.0.89.0	1.7_				-	7				+
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	3	8155-56	<0.01 <0.01	1.1	0.0 54.5									0	
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	03-04		2.9	6.9.86.		 	-		1+++	†	- (1	!//	200	+111		 	
	04-05	0.01	5.5	0.0 85.5		<u>'</u>		TH	(##		X	R16305	191			 † †	
	05-06	₹0.01	1.9	0.0 89.2		İ					7	177	iρ				
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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 <p> ∠ 0.01</p>
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

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

COMPANY.	EL PASO NATURAL GAS COMPANY	DATE ON 5/31/59 FILE NO. RP-3-997	
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LOCATION.	SEC 33 - T30N - R6W	REMARKS SAMPLED BY CLIENT	
	SAND LIMESTONE CO	NGLOMERATE (0.28) CHERT FRACTURES	

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	43-44	0.01		0.0 94.4		
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12	45-46	0.01		0.0 89.5		
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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
79287930	2	0.59
7930-7931	1	0.05
7932-7936	<u>4</u> · · · · · ·	0.05
TOTAL	24	

Weighted Total = 3.51 md

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

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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	i	
7906-7907	1	0.02
7907-7908		< 0.01
7908-7909	1	< 0.01
7909-7910	· 1	0.06
· -	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		< 0.01
7915-7916		< 0.01
7916-7917	1	< 0.01
7917-7918	1	< 0.01
7939-7940	1	4.0.01
7940-7941	1	< 0.01
7941-7942		< 0.01
7942-7943	1	0.01
7 342-7 343	` . 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	$ar{ extbf{1}}$	0.01
7963-7964	1	0.01
7964-7965	1	0.01
7965-7966	ĺ	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	J 0 01
7990-7991	1	< 0.01
7991-7992	1	< 0.01 0.02
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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	î	0.23
8016-8017	1	0.23
8017-8018	1	
2017 0010	1	0.06

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	<u> </u>	< 0.01
8029-8030	1	0.04
8030-8031	1	0.22
8031-8032	1	0.28
8032-8033	1	0.43
8033-8034	ī	0.08
8034-8035	$\overline{1}$	0.04
8035-8036	1	0.05
8036-8037	. 1	0.07
8037-8038	1	< 0.01
8038-8039	ī	0.14
8039-8040	1 .	0.35
8040-8041	<u> î</u>	< 0.01
TOTAL	62.5	3.60
Avg. $K = \frac{3.60}{60.5} = 0.058$	md	and the second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second second s

ORE LABORATORIES, INC.

Petroleum Reservoir Engineering

COMPANY.	EL PASO NATURAL	OAS COMPANY	DATE ON	7/18/59	FILE NO.	RP-3-1037_
WELL	san Juan 31-6 N	0. 16-33	. DATE OFF	_7/22/59	ENGR5	ENOLISH
FIELD	WILDCAT (BLANCO	MESA VERDE DAKOTA)	FORMATION	DAKOTA	ELEV	64991 DF
COUNTY	RIO_ARRIBA	STATE NEW MEX.	DRLG. FLD.	OIL EMULSIO	N_MUDCORES_	DIAMOND
LOCATION.	SEC. 33-T31N-R6	¥	. REMARKS	SAMPLED BY	REPRESENTATIV	e of client.
	SAND	LIMESTONE CO	NGLOMERATE	0::3	CHERT	3
	SHALE	DOLOMITE 777	VERTICAL FRACTURE]
	These analyse yes, this type	s, apinions or interpretations are based an observation is made. The interpretations or apinions expressed ro	ns and material supplied by the present the best audyment of Co	client to whom, and for whose tre behaveteries, the cult errors	estivite and rentidential and amissions excepted'.	

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2 <u>1</u> 22	60-61	0.01	3.8	0.0	15.8							X - #.	*				
23	61-62	0.02	5.6		17.9			ЩЦ					*				
24	62-63	0.01	3.7		27.0						11111		<u>*</u>	<u> </u>			
25	63-64	0.01	2.8	0.0	50.0			$\parallel \parallel \parallel$	1111				<u> </u>	 		 	#
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40	06-07	0.01	1.2	0.0 58	.2		\prod]]]			Ш			Į,		X.			1			
41	07-08	0.01	0.9	0.0 66	.6		\prod					Ш			TX		<u> </u>		刊		\prod		
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44	8012-13	⊴0.01	3.6	5.5 80	.6	<u> </u>	[Ш				Ш.			X 9	;] <u>-</u>	[X]	φ				Ш	
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46_	15-16	_0.23_	9.1			ļ			14.	<u> </u>				X.	2		X		-	;	Ш	$\parallel \parallel$	8
47	16-17	0.54	6.7				╢∔	-	111					X	31	- ',' :-	X .		1-11			٩H	
48	17-18	0,06	4.0	0.0 32	.5				+++	11.	-				XI		*		111	- - -	111	9	
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53	8029-30	0.04	2.7	7.4 14	.8		†								X	<u></u> 8030	X.	li	İĦ	Ш			
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56	32-33	0.43	5.0		,										άl		X		1				15.1
57	33-34	0.08	4.8	10.4 35											χŊ		EX.				c		1
58	34-35	0.04	5.0												× 🁌	8035	X.		111	Π		117	y ,
59	35-36	0.05	7.7	6.5 26	.0								!!	X	Ŋ		X			\prod	Π	ß	
60	36-37	0.07	8.3	2.4.19	.3		IJį.							X	Ţģ		Χij		Ш		Ш		þ
61	37-38	<0.01	7.6					Ш				\coprod		X	ļģ	· · // ·	X						۱ او
62	38-39	0,14	6.1		3									Į] X	ß		X					JΚ	
63	39-40	0.35	6.2											x	9	8040	X					Ш	Y
64	8040-41	⊴0.01	7.4	0.0 21	.6]			Ш			1			ķ)	XIII			4.11	\prod	\prod	q i
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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	
7833-7834	1	0.01
7834-7835	. 1 T	0.01
7835-7836	1	0.01
7836-7837	1	0.01
	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	
7842-7843	1	0.01
7843-7844	-	0.01
1010 1011	<u>1</u>	1.50
TOTAL	13	1.62

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

COAR LE CRIMICAS

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6990-7039. Recovered 21' blk. shale, bottom o' sli bandy.
00hc 11
WHE #2
          7039-7042. Core jamaed in bul. necovered 2' olk shale.
CC.E #3
          7042-7045; Core jammed in bbl. necovered 3 blk smale.
CORE #4
          7800-7630. Resevered 25 1/21.
                      1. shale, gry-bix, platy, all sandy, micaceous, or coal
                      2. said, gry, vig, cale, sil silty, scattered idea., duse
                      3. Shile, Ma, Micasoous, w/scuttered send lenses, 15% sand
                      4. sand, gry, vfg, calc, very silty, smale stringers, abdt
                          rica, once, tite...
                      5. same
                      6. same, 20% bik shale
                      7. shale and samu in alternating layers, predominately shale
                          shale, blk, sli sandy, calc, adcaceous
                      9. same, a/peurly pelecypod frags
                     10. saue
                     11. Easte
                     12. Same
                     13.. same
                     14. same, concentric fractures parallel to bedding
                     15. limestone, buff-bra, dase, silic, crypto-kla, horizontal
                         fractures
                     16. shale, bl., sli sandy, micaceous
                         ware, concentric fractures parallel to bedding
                     17.
                     18.
                          same, no fractures
                          shale and sand in alternating layers, predom. shale
                          shale and case in olternating layers, predom. and
                     20.
                     21. sand, gry-un, ig, hard, dose, scattered intergranular
                          poro
                         same, ali silty, w/norizontal fractures
                          sume, snaley (40%), micaceous
                     23.
                     24. shale, Dlk, micaceous (75%); sand (25%)
25. sand, gry, Sg, hard, micaceous, Wabut pyrite
```

COLE #5 7830-7831. No recovery.

CURE #6 7831-7844. Full recovery.

- 1. Jand, gry-wh, fg, hard horiz. True, or fair intergranular soro
- 2. same, within smale portings, tr fair poro
- 3. same, no Prac, tr dair poro

26. sume (60%); smale (40%)

- 4. same, sli silty, triair poro
- 5: same
- 6. same, fair poro
- 7. same, tr fair poro
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- y. Six in 8

11. Time, within shale partings

12. Same, in fair poro

13. same, simile (20%), or poro

7844-7844. Full recovery. Wite 27

1. sand, gry-an, fg, hard, or intergranular poro 2. same, w/scat shale partings and horiz frac

3. same

4. Salie

ABBREVIETIONS USED IN SERFLE & SOME DESCRIPTION

4 - angular abdt - soundant bent - bentonite (itic) blk - black brn - brown calc - calcareous dase - dense fg - fine grained foss - fossiliferous frac = fractured
frag = fragment(2) fx - finely crystalline glau - glauconite(ic) e grn - green gry - gray horiz - horizontal 1GR: - intergranular "incl - inclusions lg - large grained

is - limestone as - medium grained poro - porosity pyr - pyrite Atzitic .- quartzitio h - rounded SA - subangular scat - scattered sdy - sandy sh - shale silie - siliceous sli - slight SR - subrounded
SS - sandstone
tr - trace V - very vert - vertical wh - white xln - crystalline

With Markels unta

ALPES NO.	DLFTH	YTlatenavday CYOMAGIATh	AEL TOPPOLITY	Total longlity
<u> </u>				
1	783 2	ુ.ગ	4.20	4.65
2	7833	J.J1	2.75	3.70
3	7834	0.01	4.10	4.42
4	7835	ə . əi	1.17	- 2.08
5 .	7836	5.01	1.77	್ಷ-81
6	783 7	0.01	∠	5٠50
7	7838	J.JL	.3.08	7.80
8	7839	2.31	8.50	9.50
ÿ	7640	٠	7.20	i.70
10	7841	0.01	2.76	2.16
11	7842	0 .01	2.65	2.53
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.



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 Clifis 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. Overburden pressure causes only a small decrease in porosity, which can usually be ignored. 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 or nonexistent. 3

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70° C), the gas (N₂) permeability of each core was measured in a Hassier 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. 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 came 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 overbuiden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

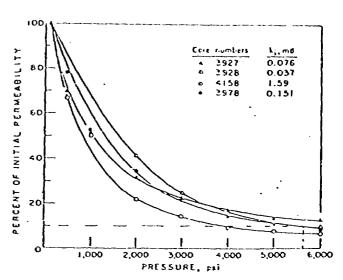


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

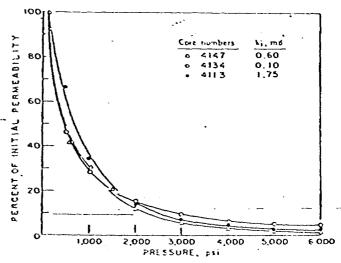


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

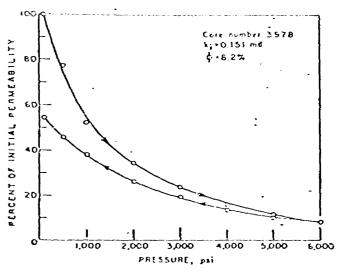


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1--EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overh	uiden Pies	svre (psi):		500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k, ý			Pt	rmeshility (mo	3)	NAMES OF THE OWNER,	
Gesbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0165	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	9.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4346**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.059	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	0.000	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	0.015
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

^{*}Number denotes depth in feet,

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 researchers²⁻³ 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 al-

though 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

Malet 25int	alion (percent):	_0_	20	40_	- 60		
Core Number	(ba)		Permeab	lity (md)	<u>))</u>		
Gesbuggy							
3927	100	0.115	0.099	0.041	0.0023		
3927	3,900	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 Whe	el						
8084	100	0.038	0.030	0.014	0 0042		
2303	3,000	0.012	0 0095	0.0043	0.0013		
8084	6,000	0 6070	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		
30156	3,000	350.0	0 020	800 0	0.0008		
10156	6,000	0.017	0.013	0.005	0.0005		

[&]quot;Slightly Iractured.

Unitial permeability.

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 climinate 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 insitu 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

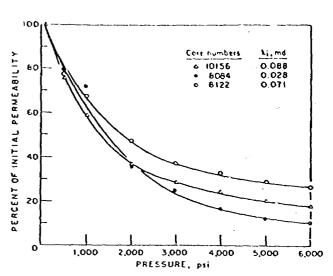


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

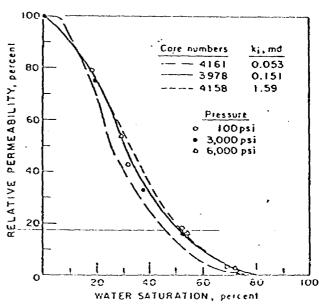


Fig. 5—Relative gas permeability of Gasbuggy cores.

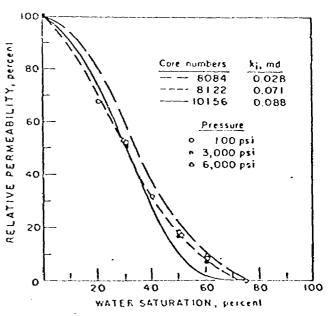


Fig. 6-Relative gas permeability of Wagon When cores.

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 overbuiden 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 pressureeffect 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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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 = $\frac{35.36}{286.2}$ = $\frac{0.124 \text{ md}}{286.2}$

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

EXHIBIT NO. 16 ·

Natural Production Tests (Pitot Tube)

	1. El Paso Natural Gas Co. 2. Northwest Pipeline Corp. 3. Northwest Pipeline Corp. 4. Northwest Pipeline Corp. 6. Northwest Pipeline Corp. 7. Northwest Pipeline Corp. 8. Northwest Pipeline Corp. 9. Northwest Pipeline Corp. 10. Northwest Pipeline Corp. 11. Northwest Pipeline Corp. 12. Northwest Pipeline Corp. 13. Northwest Pipeline Corp. 14. Northwest Pipeline Corp.	OPERATOR
	San Juan 30-4 Unit No. 39 San Juan 30-5 Unit No. 39 San Juan 30-5 Unit No. 37 San Juan 30-5 Unit No. 49 San Juan 30-5 Unit No. 73 San Juan 30-5 Unit No. 72 San Juan 30-5 Unit No. 47 San Juan 30-5 Unit No. 47 San Juan 30-5 Unit No. 48 San Juan 30-6 Unit No. 38 San Juan 31-6 Unit No. 38 San Juan 31-6 Unit No. 38 San Juan 31-6 Unit No. 35 San Juan 31-6 Unit No. 35 San Juan 31-6 Unit No. 35	WELL
14 WELL AVERAGE 13 WELL AVERAGE	SENW 18 30-4 SWNE 7 30-5 NESW 8 30-5 NWNE 10 30-5 NWSW 10 30-5 NWSW 17 30-5 NWNE 18 30-5 NWNE 20 30-5 NENW 2 30-6 NENW 2 35 31-6 NENE 35 31-6 SESE 35 31-6	LOCATION
E (Excluding Well No.	8615 7822 7870 7780 8035 7905 7820 7820 7890 7891 7870 7890 8080 7928	NATURAL PRODUCTION TEST DEPTH
(1 No. 8)	8425 7686 7688 7683 7919 7790 7794 7790 7832 7806 7796	DAKOTA DEPTH
42: 288	527 161 666 TSTM 338 338 264 2174 128 370 241 TSTM 338 370	PRODUCTION RATE NATURAL (MCFPD)
2450 2525	2506 1703 3944 855 2635 2456 1209 1610* 2035 3691 2828 2557 2643	PRODUCTION RATE AFTER FRAC (MCFPD)

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

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

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 $667^{\circ}R$

2 = 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 2

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:

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

7317

BEFORE: Richard L. Stamets

APPEARANCES

TRANSCRIPT OF HEARING

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 F. A.
Jefferson Place
Santa Fe, New Mexico 87501

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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 quality d 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:

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

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

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formation there; we're coming out of the San Juan Basin in that area.

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

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

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two ways of estimating natural flow.

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

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.

Does Southland Royalty Company also have plans in the area?

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 racord be held open to permit us to submit the written results of the Southland Royalty Company test as sconas 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.

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

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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.

vith 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.

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 IF 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?

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.

lation 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.

1 2 They also did the same and came up with 3 a 224 Mof of gas per day average for the Rosa area. What is the production limitation pre-5 scribed by the Oil Conservation Division rules for a depth of 6 7950? This is 336 Mcf of gas per day, so we're below it. MR. STAMETS: In either event. 10 In either event. 11 Just additional information to try and 12 tie in more of the acreage, to indicate that my initial -- my 13 additional information was holding throughout the area. 14 Will you now refer to Four Corners Ex-15 hibit E and review this for Mr. Stamets? 16 Exhibit E is the economic criteria re-17 quested by the Commission. I worked with Frank Chavez on 18 these numbers and we came up with a production rate, listed 19 there under No. 1, for an average Rosa Well throughout the 20 entire area, Year 1 to be 330 Mcf of gas per day; Year 2, 21 205; Year 3, 145; Year 4, 115; and Year 5-on with an 8-1/2 22 decline in our yearly production. 23 This forecast was constructed by using 24 an IP of 2100 Mcf of gas per day for Rosa -- for all the 25

average Rosa wells, or for the entire Rosa wells in the area.

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They averaged 2100 Mof 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 Bof for 33 walls 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 Mof 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.

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

MR. STAMETS: How about 10 percent?

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 and be drilled and produced in the -- drilled and fraced and ready for completion

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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

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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.

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 lir. 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.

Practor 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.

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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.

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.

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

Once again, yes, that's -- this is A 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.

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

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.

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 ratural 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.

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

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Yes, all but Exhibit D, which was, as I stated, presented to me by Mitchell Energy Corp. And your -- does your review of these exhibits indicate that they are correct and accurately portray the data you are attempting to show? Yes, they do. MR. CARR: At this time, Mr. Stamets, we would offer Exhibits A through E. These exhibits will be MR. STAMETS: MR. CARR: I have nothing further of Mr. McCord on direct. CROSS EXAMINATION BY MR. STAMETS: Mr. McCord, Exhibit E, the last page of your economic exhibit. Yes, sir. In Case No. 1 you're looking at what you consider to be the lowest possible well cost in the area? That is correct.

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?

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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.

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

counted 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

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eri _n	2	printout. This was information that they considered confi-
	3	dential and did not want to present unless we we absolutely
	4	had to.
	5	We can confer from that DROI 15 number
	6	that your return would be less excuse me, somewhat more
	7	than 15 percent, but the actual number, we don't have.
	8	MR. STAMETS: Other questions of this
	9	witness?
	10	MR. CHAVEZ: Yes, sir.
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	12	QUESTIONS BY MR. CHAVEZ:
	13	Mr. McCord, in a discounted rate of re-
. *	14	turn what does the absolute number zero indicate? Does that
	15	indicate a break even point?
	16	A Yes, it does.
,	17	Q At 15 percent.
	18	A. That's right. That would mean that
	19	your money is worth all that is doing is taking your future
	20	monies and bringing it to the present.
	21	Q Okay. The average depth for the Dakota
	22	in these townships, how did you arrive at that again?
	23	A. I every well involved in the area, I
	24	took the top of the Dakota formation and we averaged that
	25	number.
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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.

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.

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

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

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?

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.

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.

Do you know what depth the Southland

RECROSS EXAMINATION

BY MR. STAMETS:

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

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

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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.

\$820,000, or more indicative cost, that's -- that's not economic, no.

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

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

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

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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.

Mell, 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

26 1 2 a difference in philosophy of the companies. 3 Now that's just the stimulation costs, is a big factor there. That certainly doesn't account for all 5 the difference in those costs. Those are just the costs reported to me. 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. If they got the 103 price? Right. 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. So the Exhibit E estimates that every 21 well will be a producer and does not try to take into account 22 a certain number of dry holes in respect to the average re-23 covery for the entire area. 24 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.

A. Yes, greatly.

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.

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.

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-

It wouldn't take but one, probably. One in four, one in five, one is three, one in two? 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? Uh-huh. That would mean that if you had got every other hole a dry hole, it would be a break even 16 proposition. So what would that, say, if you had one dry 17 hole in four, it would be a money making proposition? 18 Considering that \$470,000 that sounds 19 reasonable, yes. Once again, though, that's one instance 20 where they claim they can drill it for that -- that type of 21 money, and we have -- and that was just a number presented 22 to me and the last seven wells, or the last three wells Amodo 23 has drilled and the last four wells Mitchell has drilled in 24 the area cost \$800,000, so therefor, considering that \$470,000 well cost for those, it's not reasonable at all.

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That's a good question. This could be

a personal feeling, but I personally think that -- that you

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need to put more of a fracture stimulation on these wells, which would increase your cost.

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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, sic. 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. 16 McCord may be excused. 17 Are there any other statements? With the provision for the other information that we've discussed here, the case will be taken under 20 advisement. 21 (Hearing concluded.)

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SALLY W. BOYD, C.S.R. Rt. 1 Box 193-18 Santa Fe, New Mexico 87201 Phone (303) 455-7409

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREPY 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.

Souly W. Boyd C.S.R.

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

By whom are you employed and in what capacity?

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

Have you previously testified before

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2	this Commission or one of its examiners and had your creden-
3	tials as a petroleum engineer accepted and made a matter of
4	record?
5	A. Yes, I have.
6	Q. Are you familiar with the application of
7	Four Corners Producers Association in this case?
8	A. Yes, I am.
9	Are you familiar with the subject area?
10	A. Yes.
11	MR. CARR: Are the witness' qualifica-
12	tions acceptable?
13	MR. STAMETS: They are.
14	Q Mr. McCord, will you briefly state what
15	Four Corners Gas Producers Association seeks with this ap-
16	plication?
17	A. The Four Corners Gas Producers Associa-
18	tion is applying for a portion of the Basin Dakota gas field
19	to be designated as a tight formation under Section 107 of th
20	Natural Gas Policy Act of 1978.
21	The proposed Rosa tight gas area is
22	located in the northeastern portion of the San Juan Basin.
23	The area is approximately 25 miles northeast of the town of
24	Bloomfield in northwestern New Mexico, and covers portions of
25	Dio Arriba and San Juan Counties.

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Q			Have	you	prepared	certain	exhibits	fo
introduction	in	this	саве	?				
λ.			I hav	ze.				

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.

Mill 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?

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.

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

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

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gical characteristics of the Dakota?

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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.

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

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.

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?

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

1	11					
2	very sparse drilling in that area. Only one well was drilled					
3	and that would be in Section or Township 30 North, Range					
4	3 West, Section 34. A Dakota well was drilled by Sunray DX					
5	Oil Company, Jicarilla Tribal No. 1, in September of '64.					
6	It was drilled and abandoned.					
7	Other than that there is no control to					
8	the east part of the area.					
9	Q In your opinion is the Dakota continuous					
10	across the basin?					
11	A. Yes, it is.					
12	Q What is the porosity range within the					
13	area governed by the application?					
14	A. Overall the Dakota sand has a porosity					
15	range of from 1/2 percent to 11-1/2 percent in the Rosa area,					
16	with the average pay porosity being in the neighborhood of					
17	4 to 6 percent.					
18	Q Is the in situ permeability cutoff in					
19	the Rosa tight gas area less than .01 millidarcy?					
20	A. Yes, it is. The formation is dependent					
21	upon stimulation techniques to be commercially productive.					
22	a And have you calculated permeability for					
23	the area?					
24	A. Yes, I have.					
25	Q Would you please refer to Applicant's					

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Okay. Exhibits Numbers Seven through

Exhibits Seven through Twelve and review these for Mr. Stamets

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.

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

Exhibit Number Thirteen presents a

1 13 2 technical paper entitled Effect of Overburden Pressure and 3 Water Saturation on Gas Permeability of Tight Sandstone Cores, which was written by Rex D. Thomas and Don C. Ward of 5 the U. S. Bureau of Mines. 6 This paper presents relationships between laboratory determined permeability in cores and actual in situ permeability found in reservoirs. 9 Exhibit Number Fourteen explains how in situ permeability is calculated from the core analysis, using 10 11 the technical paper presented. 12 Will you now refer to your Exhibit Number 13 Fifteen and explain this exhibit? 14 Exhibit Fifteen is a summary of all 15 laboratory core analysis results for the Rosa tight gas area. 16 An average in situ permeability value of 0.012 millidarcy 17 was calculated from the average laboratory permeability value 18 of 0.124 millidarcy for the Rosa area. This in situ perme-19 ability value is well below the 0.1 millidarcy tight gas 20 cutoff. These permeability measurements substantiate that 21 the Dakota formation is very tight in this area and must be 22 stimulated to obtain commercial gas production. 23 Mr. McCord, can gas be produced in commercial quantities from the formation in the subject area 24 without stimulation?

No, it cannot.

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?

stimulated 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 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.

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

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these tests have many factors which leave their results questionable.

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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.

Have you calculated the unstimulated gas

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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.

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.

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well?

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

MR. STAMETS: What's the location of that

A Okay, Section 35. 31, 5.

MR. STAHETS: 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 aguifers 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.

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.

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.

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.

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

ability 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

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2	all the specifications required as stated above and should			
3	be designated a tight formation in the Basin Dakota Pool under			
4	Section 107 of the Natural Gas Policy Act of 1978.			
5	0 Mr. McCord, has this area been approved			
6	for infill drilling?			
7	A. Yes, it has in May of 1979.			
8	Q And that was by Commission Order R-1670-V			
9	A. Yes, I believe so.			
10	Q Have any infill wells been drilled in			
11	the subject area?			
12	A. There have been a few infill wells			
13	drilled in this area after I have gathered all the data for			
14	this report. I'll point those out. They are both John Schalk			
15	wells. One would be in the southeast			
16	MR. STAMETS: Start out with the township			
17	and range.			
18	A. Sure.			
19	MR. STAMETS: It makes it a little easier			
20	to find.			
21	A. Okay, 30, 30 North, 5 West, Section 2,			
22	southeast quarter.			
23	The other well being in 30 North, 5 West			
24	Section 12, I believe the northeast quarter.			
25	These are recent wells that have been			

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2	drilled. My information or this map is May of 1981, so these					
3	are recent wells and it's my understanding have not been com-					
4	pleted at this time.					
5	Q How would you characterize the develop-					
6	ment of the subject area on the original 320-acre spacing?					
7	A. Very, very sparse development under 320					
8 .	acres. I believe I calculated under the existing acreage 53					
9	producers. This is only 6 percent of our 320-acre spacing,					
10	and to my knowledge these two Schalk wells mentioned are the					
11	only two infill wells that have been attempted in the area.					
12	I believe that might have had something to do with that man's					
13	holdings in the area more than all the economic criteria					
14	involved.					
15	g Mr. McCord, in your opinion will further					
16	development of the subject area depend upon approval of this					
17	application and the resulting incentive price?					
18	A. I think, yes, to be adequately developed					
19	this area will need the 107 price to make it economically					
20	feasible.					
21	Q Will you please refer to and identify					
22	what has been marked as Applicant's Exhibit Eighteen?					
23	A. Exhibit Eighteen is a written text ex-					
24	plaining each of the exhibits I have just presented.					
25	Q And this text was submitted with the					

1	25			
2	exhibits to the Commission and USGS?			
3	A. Yes, that's correct.			
4	Q Were Exhibits One through Eighteen pre-			
5	pared by you or have you reviewed each of these exhibits and			
6	can you testify as to their accuracy?			
7	A. Yes, I can. There were prepared by me.			
8	Q In your opinion will granting this ap-			
9	plication result in the production of gas that otherwise woul			
10	not be produced?			
11	A. Yes.			
12	Q Will granting this application be in the			
13	best interest of conservation, the prevention of waste, and			
14	the protection of correlative rights?			
15	A Yes, it will.			
16	MR. CARR: At this time, Mr. Stamets, we			
17	would offer into evidence Applicant's Exhibits One through			
18	Eighteen.			
19	MR. STAMETS: These exhibits will be			
20	admitted.			
21	MR. CARR: Mr. Stamets, I've been asked			
22	to direct certain questions to Mr. McCord on behalf of the			
23	USGS and I'll be happy to do that now or at a later time,			
24	whenever you desire.			
25	MR. STAMETS: Well, why don't you just			

2 production. In reviewing the wells presented and the two 3 cross sections, being Exhibits Number Five and Six, in some 4 wells more than four zones were perforated. The question is, is this application 6 asking for all zones in the Dakota to be designated as a 7 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. 10 The question is, are you asking for all 11 of the zones in the Dakota to be designated tight formations? 12 Yes. The Four Corners Gas Producers 13 requested that the entire Dakota section as defined 400 feet 14 below the base of the Greenhorn be designated as a tight 15 formation. 16 Is this application asking for a tight 17 sand designation for infill locations within the Rosa tight gas area, and there are certain examples given here. First, 18 in Township 30 North, Range 5 West, Section 9, there are ap-19 parently two infill locations. Is it the request of the ap-20 21 plicant that these be included in the tight sand designation? 22 Yes, it is. à.

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

Yes, those also.

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2	Q In Yowr.ship			
3	MR. STAMETS: What was the last section?			
4	MR. CARR: Section 20. All of this first			
5	group, they are all in Township 30 North, Range 5 West.			
6	MR. STAMETS: And there are two in there			
7	or just one?			
8	MR. CARR: Two, according to the question			
9	MR. STAMETS: Infill locations in Section			
10	9 and 20			
11	MR. CARR: And 10.			
12	MR. STAMETS: And 10. Let me get 10			
13	marked on my exhibit, please.			
14	MR. CARR: All right. Now in Township			
15	31 North, Range 5 West, one location in Section 8.			
16	A Okay. I believe there should be two			
17	locations in Section 8. I do not have an infill well in that			
18	location, or in that section. I believe that should be two			
19	locations, and yes, we are asking for that also.			
20	And, again, two locations in Section 11			
21	and in Section 17?			
22	h Yes.			
23	a And now in Township 31 North, Range 6			
24	West, two locations in Section 27 and two locations in Section			
25	35.			

1 29 2 Yes, we ask that these be part of the 3 application as well. MR. STAMETS: What was the second section 5 please? 6 MR. CARR: 35. So you are asking that all infill locations within the Rosa area be included within the tight sand designation? 10 That is correct. 11 Mr. McCord, I direct your attention now 12 to Exhibit Number Three, and it indicated that 12 Dakota wells 13 were drilled in 1980, and 9 Dakota wells were drilled in 1981, 14 all at current 103 prices. 15 Is it no longer economical to drill 16 wells such as those drilled in 1980 and '81 under 103 prices? 17 Yes, it would still be economical to 18 drill some of these never wells that were drilled in 1980 and 1981 under 103 prices if there were -- existed any good pro-19 20 ducing characteristics such as exhibits by those wells. As 21 to the current time there are not any of this type of location 22 available. Therefor, to continue to drill wells in this area 23 the 107 price would be necessary to -- to substantially com-24 plete the area.

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Is it your answer that if there were

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2	comparable locations in the Rosa area that the wells could		
3	be drilled at 103 prices?		
4	A Yes, it's my feeling they could.		
5	Q At this time, based on your study, you		
6	do not believe there are comparable locations?		
7	A. I don't believe that, no.		
8	Q Is the 107 price necessary to have an		
9	economical well that would be similar in production potential		
10	to those drilled in 1980 and 1981?		
11	A. Yes, it would be necessary because as we		
12	stated before there are no more wells of the calibre drilled		
13	of the ones in 1980 and '81 with with that calibre for		
14	103 prices; therefor, the 107 is needed.		
15	Also, there is no more drilling, the		
16	drilling plan for 1981 has been discontinued in this area		
17	because of the marginal economics.		
18	a Mr. McCord, could you provide economic		
19	data as to the rate of return on showing comparison of		
20	several of the 21 wells that were drilled in 1980 and 1981,		
21	using the 103 price and contrasting that with the 107 price?		
22	A Yes, it is possible to provide this		
23	economic data, although in the instance of this area, there		
24	is mainly developed on 320 acres, acre spacing, and it's my		
25	understanding that economics are not required of 320-acre		

1 2 spacing in the Dakota. 3 Of the 21 wells that were drilled in 1980 and '81, do you know if the economics on these wells made them attractive prospects? Yes, in some of the wells they were at-7 tractive prospects under 103 prices, but it is my understanding 8 that some of these wells drilled in '80 and '81 were demand 9 wells. Also, some had marginal 103 economics. This is exemp-10 lified by the fact that the drilling in 1981 has been discon-11 tinued for the area because of the low profitability of these 12 wells. 13 MR. CARR: I have no further questions 14 of Mr. McCord. 15 MR. STAMETS: Are there other questions 16 of the witness? Mr. Chavez? 17 18 QUESTIONS BY MR. CHAVEZ: 19 How many unspud Dakota locations or non-**20** · completed Dakota wells are there in this area at this time? 21 Okay, Mr. Chavez, I have them marked 22 on my map. Once again, the map is dated as of 5 of 81, so 23 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,

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2	the northwest quarter.			
3	Ω Has it been completed or just spud?			
4	A. To my knowledge it's either I don't			
5	have the information as to at this time what stage of prog-			
6	ress it's in. It has been staked and is a possible location			
7	for a future well. That's really the only thing I'm sure of.			
8	That's what I have marked on the map.			
9	Also, in 31 North, 6 West, Section 14,			
10	in the northeast quarter, the Amoco Rosa 67. It's my under-			
11	standing that this well is dry in the Dakota and Amoco is			
12	possibly going to recomplete in the Mesaverde or PC in this			
13	well.			
14	All right, in 31 North, 5 West, Section			
15	20, the northeast one quarter, the Rosa No. 85.			
16	In that same township and range, Section			
17	33, southwest quarter, the Rosa No. 77.			
18	In 31 North, 4 West, Section 7, the			
19	northeast quarter, Mitchell, the Rosa No. 81.			
20	In Section 9 of that same township,			
21	southwest quarter, the Rosa 82 by Mitchell.			
22	Section 12, in the northwest quarter,			
23	the Amoco Rosa No. 87.			
24	Section 15, northeast quarter, Mitchell			
25	Rosa No. 83.			

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2	Q.	Section what, I'm sorry?	
3	A.	25. No. 82.	
.4	Q.	What was that, I'm sorry?	
5	አ.	That's the 30-5 Unit No. 82, the northwest	
6	quarter of 25, 30-5,	okay?	
7	Q	Okay.	
8	A.	Section 27, the southwest quarter, 30-5	
9	Unit No. 81, and Section 36, the northeast quarter, the 30-5		
10	Unit No. 77.		
11	-	That is all the wells I have that are	
12	staked in this area	as of this time.	
13	Q.	Is the drilling of these wells pending	
14	the outcome of this	hearing? Or is it just pending rig	
15	availability?		
16	A.	I cannot tell you the actual answer to	
17	that. I don't know	what the future plans on these wells, if	
18	any of them have bee	en completed. I know some of them have	
19	been drilled but I would not be able to separate each one		
20	out. I've just pich	ked them up through PI as possible locations	
21	in this area. I do	not know the status of them all.	
22		MR. CHAVEZ: That's all the questions	
23	I have.		
24		MR. STAMETS: Are there other questions	
25	of the witness? Mr	. Padilla?	

1 35 2 CROSS EXAMINATION 3 BY MR. PADILIA: 4 Q Mr. McCord, you testified about comparable 5 locations. What do you mean by a comparable location? Does 6 that mean -- I think it would mean that that's a good location. 7 Are you saying that in this area you've run out of good loca-8 tions now? 9 Yes. In my talks with Phillips Petroleum P. 10 Company, who is mostly in this 30-5 Unit, they have drilled 11 most of these newer wells and from talking with these people, 12 their feeling is that -- that all of their good drilling 13 locations have been used up. 14 What have they based their justification 15 for --16 To tell you the truth, I couldn't answer A. 17 That's just information they supplied to me. that for you. 18 And that's the same thing for the same 19 calibre, same calibre, quote, same calibre of location, is 20 that the same thing? 21 Yes. Yes. 22 Can you tell me what marginal economics 23 are for drilling Dakota wells in this area? 24 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.

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.

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.

Wouldn't you have to apply the dollar

amount in order to determine whether or not you should get the incentive price?

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.

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.

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

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1	38				
2	of that one well that I mentioned on there.				
3	A No wells to the Dakota, that is that				
4	is correct. This would be an area that the 107 prices would				
5	virtually be a must for the exploration of. Obviously, no				
6	one has thought under 103 prices this area is worth prospection				
7	The 107 would would encourage drilling of wells in this				
8	area.				
9	Q Is this is this area unitized cur-				
10	rently under do you know?				
11	A. I don't believe it's under a unit agree-				
12	ment, not the farther east. Most of the most of the newer				
13	wells are under existing units.				
14	Q Is this east half area drilled in shallow				
15	formations?				
16	A. It might possibly be but I don't have				
17	that information. I've just concentrated on Dakota wells.				
18	To my knowledge, if so, there would be very, very few wells.				
19	Q You don't know whether there are any				
20	Pictured Cliffs wells, Pictured Cliff wells at all in this				
21	area?				
22	A. Not offhand I don't. I would have to				
23	check, check my PI cards to see if any were drilled.				
24	MR. PADILLA: I believe that's all I				
25	have, Mr. Examiner.				

BY MR. STAMETS:

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.

CROSS EXAMINATION

A Yes, sir, that's correct.

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.

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.

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.

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

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rates too high, is my feeling. I think the actual production, the stabilized production rate, would be much lower than they report.

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?

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,

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under the current 103 price.

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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

which would demonstrate the wells in the area are not economic

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you intend to use to provide this data.

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after we meet with Mr. Chaver we will -- and agree on exactly

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what data is going to be required -- we'll notify all those

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who appeared in this case of what additional information has

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been requested.

be offered.

21 22

there is any evidence which could be brought in that would

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help relative to 30 and 31 North, 2 and 3 West, that should

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Is there anything -- any other questions

MR. STAMETS: I'd also suggest that if

MR. CARR: We'll be grad to do that and

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

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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

1	46			
2	this Commission and also by the FERC as it reviews your re-			
3	commendations.			
4	Thank you very much.			
5	MR. STAMETS: Are there any other state-			
6	ments at this time?			
7	Go off the record a second.			
8				
9	(Thereupon discussion was			
10	had off the record.)			
11				
12	Is there anything further in this case			
13	today?			
14	This case, then, will be continued to			
15	the August 26th Examiner Hearing.			
16				
17	(Hearing concluded.)			
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CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREPY 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.

Saly 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_____ , Examiner Oil Conservation Division

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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.

7317

BEFORE: Richard L. Stamets

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TRANSCRIPT OF HEARING

APPEARANCES

For the Oil Conservation Division:

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

For the Applicant:

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

and

Gary Paulson, Esq.
Amoco Production Company
17th and Broadway
Denver, Colorado 80202

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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.

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:

Township 30 North, Range 2 West, N.M.P.M. Sections 1 through 36: All

Township 30 North, Range 3 West, N.M.P.M. Sections 1 through 36: All

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- 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 <u>situ</u> 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.

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.

William F. Carr

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Case >3/7

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Containing a total of 270,260 acres, more or less.

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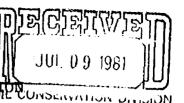
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William F. Carr

BEFORE THE

OIL CONSERVATION DIVIS



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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William F. Carr

Memo

From

PRENTISS CHILDS

To

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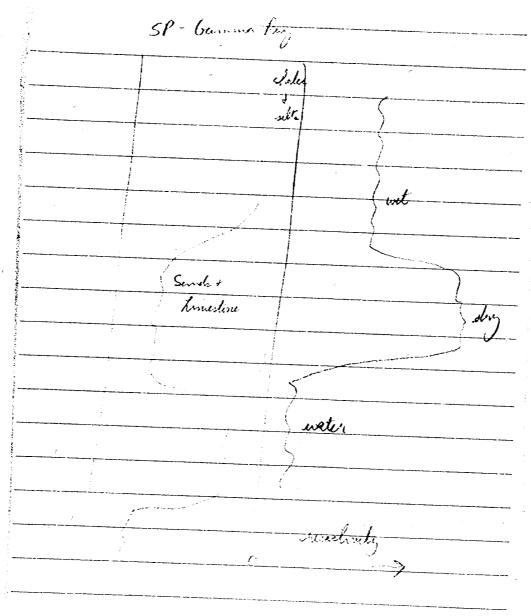
Oil Conservation

Santa Fe, New Mexico



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CARBON STEEL • STAINLESS STEEL • ALLOY • ALUMINUM

Kevin H. McCord w/ Four Corners Gas Buolucers Association - Exhibit A - electric log showing tope of formations, the Streenhorn, Graneron, & Dahata, are shown, Dahata @ 2300! of E.L. Potest Monero Dome +1 (30N-1W- 24) aprox. 6 min East (sieff met) Ang. in 7950' for the Rosa tight gas area. due to steep upward trend of the form.

Exhibit B - we data from Rochey De Villiera #31 1 W. Durilla buted 4mi. couth # 21, 29 N, 3W. page 1 - summery of core analysis + leb perm = 0.018 md - 10 10 1 = 00 2 - actual core analysis results ->

Examiner Heaving

	1011 Pl-1 . I de
7	I. Exhibit A: Electric log showing formation tope E. I. Potal shower
was and a state of the state of the	A. Greenhorn Dome # 1 (300-100)
erren en en en en en en en en en en en en e	B. Gruneror appr. 6 mi. exet of me
Z	I. Exhibit E: Core date from Rodney De Villiere #31-1W Juille
	II. Exhibit E: Core date from Rodney De Velliere "31 - 1 W Jecarella located 4 mi. stath in 21,29 N, 3 W.
	A. Paze one: summun 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 ml. in situ form.
	3. estimated 15% 20 MEF of see par day from 05%.
	4. Daring law presented previously results in a 9 Mc F per day
and decides, we have the second decided	flow rate.
ner manifel the second sector	B. Page two : actual core analysis results
	III, Cand hole DST by Pan Am Corp. on Junilla # 1 Payora Brated 3mi.
	North in 23 - 32 N - 3 W. Whe mable to come up w/ any
	reliable furm infor , also turned out to be a day tole
	IV. Southland Payalty Sims Fed. #1 13,30N, 4W is at fresent
7	dulling and will submit DST results when data is available.
	J. Sunray DX Quantla Vulal #1 -dry hole.

CAMPBELL, BYRD & BLACK, P.A.

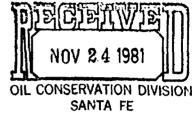
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BFADFORD C. BERGE
WILLIAM G. WARDLE
KEMP W. GORTHEY

JEFFERSON PLACE
SUITE I - 110 NORTH GUADALUPE
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87501
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-8043

Növember 24, 1981

Mr. R. L. Stamets Technical Support Chief Oil Conservation Division Post Office Box 2088 Santa Fe, New Mexico 87501



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

WFC:1r

Enclosure

cc: Mr. Kevin McCord

western

union OC LOE

union

AYA105(1254)(1-018427M237)PD 08/25/81 1247 TLX ARCO TLX A DAL

ZCZC 01 PD DALLAS, TEXAS 8-25-81

THE NEW MEXICO OIL AND GAS CONSERVATOR DIVISION SANTA FE

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 O. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARP
BRADFORD C. BERGE
WILLIAM G. WARDLE

JEFFERSON PLACE
SUITE I - 110 NORTH GUADALUPE
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87501
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

July 9, 1981

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

WFC:1r

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: Hest 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 N of Section 9; and Fee Well No. 8 in Unit C of Section 8.
- CASE 7337: Application of Beartooth Cil & 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 11/2 of Section 28, Township 28 North, Range 8 Nest, 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 Hexico.
 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 Norrow 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 1303: (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 Welfcamp 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-663b 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, us 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 "H" Well No. 1 in
 Unit M of Section 29, Township 5 South, Range 33 East, South Peterson Field.

JAR.

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.

Ohn-

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 <u>day of November</u>, 1987, 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

-2-Case No. 7317 Order No. R-

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

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 Countries.

(5)(A) That within the Basin Dakota Gas Pool are large areas of extensive development and large areas of very limited development.

(6)(8) That the area for which a tight formation designation is sought is one of very limited development 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.

- (%) 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.
- (70) (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.

(4)

-3-Case No. 7317 Order No. R-

- (1ϕ) 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.

- (4) (45) 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 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.

Case No. 7317 Order No. R-

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO OIL CONSERVATION DIVISION

JOE D. RAMEY Director

SEAL

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
 - "(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,

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 <u>llth</u> 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

-2-Case No. 7317 Order No. R-6883

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, NMPH Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 6 WEST, NMPM Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 7 WEST, NMPH 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

-3-Case No. 7317 Order No. R-6883

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 Dekots 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 Dakote 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, Ric 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)(8) of the regulations; and
 - (c) production of more than five barrels of crude oil per day.

-4-Case No. 7317 Order No. R-6883

- (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 evi-
- (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

\$ E A | •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

Exhibit A Order No. R-6883