Case No.

7361

Application

Transcripts.

Small Exhibits

ETC

JUL 26 1982
OIL CON[illegible]
SANTA FE

Southland Royalty Company

July 23, 1982

Mr. Michael E. Stogner
New Mexico Oil Conservation Division
P. O. Box 2088
State Land Office Building
Santa Fe, New Mexico 87501

RE: NMOCD Case No. 7362
Designation of Tight
Formation, Dakota Formation
(Basin Dakota Field)
San Juan County, New Mexico

Dear Mr. Stogner:

Your letter of June 4, 1982 requested additional information concerning our exhibit 13 of the subject tight gas case. I'm sorry for the delay in answering your letter.

Our phone conversation with Mr. Victor Zabel of the Federal Energy Regulatory Commission in Washington, D.C., indicated the purpose of their request was to establish wells listed in our exhibit 13 as gas wells.

We do not distinguish between oil and condensate production when reporting production to the commission. All of the wells listed in our exhibit 13 are gas wells with GOR's ranging from 26000:1 to dry gas.

1) The oil production and reserves listed in our exhibit 13 is associated condensate production.

2) Each well listed in exhibit 13 was stimulated through hydraulic fracturing techniques.

3) There is no actual oil production from the wells listed in exhibit 13. The production shown is condensate production. API gravity for these wells is in the 50 to 60 degree range.

P.O. DRAWER 570 (505) 325-1841 FARMINGTON, NEW MEXICO 87401

If you need further information, please let me know.

Sincerely,

SOUTHLAND ROYALTY COMPANY

John A. Crum

John A. Crum
District Reservoir Engineer

JAC/eg

XC: Mr. Steve Palko-SRC-Ft. Worth
Mr. Howard Kilchrist
Director of NGPA Compliance
Federal Energy Regulatory Commission
825 N. Capitol Street, N.E.
Washington, D.C. 20462

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
LARRY KEHOE
SECRETARY

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

June 4, 1982

Steve Palko
Southland Royalty Company
1000 Ft. Worth Club Building
Ft. Worth, Texas 76102

RE: NMOCD Case No. 7361,
Designation of Tight
Formation, Dakota Formation
(Basin-Dakota Field) San
Juan County, New Mexico

Dear Mr. Palko:

As per our telephone conversation Friday, June 4, 1982, Michael Boyle with the Federal Energy Regulatory Commission in Washington,D. C. requested to the New Mexico Oil Conservation Division the following supplemental information concerning Exhibit No. 13. (See attached copy.)

1) is this reported oil production either, actual crude production or condensate

2) is this reported oil production from wells that were stimulated

3) please submit actual production history from those wells having oil production

Please submit to this office three copies of the requested supplemental information.

If we may be of any assistance, please call. Thank you.

Sincerely,

Michael E. Stogner

Michael E. Stogner
Petroleum Engineer

MES/dp

cc: W. Perry Pearce
General Counsel
New Mexico Oil Conservation
Division
Santa Fe, NM 87501

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 13
CASE NO. ____

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

				Cumulative Production (1-1-80)		Remaining Reserves (1-1-80)		Ultimate Reserves	
Operator	Lease	Well No.	Location	Gas (MCF)	Oil (BBLS)	Gas (MCF)	Oil (BBLS)	Gas (MCF)	Oil (BBLS)
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper	15	NE-21-32N-12W	82,784	1,045	53,714	181	135,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Tenneco	Moore	1	NW-25-32N-12W	150,109	0	0	0	150,109	0
Tenneco	Hubbard	1	SE-25-32N-12W	430,872	0	118,134	0	549,006	0
Southland Royalty	Decker	2	NE-26-32N-12W	86,930	285	46,571	0	133,501	285
Tenneco	Moore "C"	2	NW-26-32N-12W	384,093	1,284	250,514	0	634,607	1,284
Tenneco	Moore "C"	1	SE-27-32N-12W	500,205	1,803	175,347	0	675,552	1,803
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Southland Royalty	Culpepper Martin	10	SW-32-32N-12W	402,396	3,513	352,593	690	754,989	4,203
Southland Royalty	Culpepper Martin	3	SW-33-32N-12W	256,054	1,535	361,586	1,928	617,640	3,463
Southland Royalty	Culpepper Martin	17	SE-33-32N-12W	77,114	591	1,335,936	7,636	1,411,050	8,227
Consolidated Oil & Gas	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Benson-Montin-Greer	La Plata	1	SW-30-32N-13W	183,726	0	187,451	0	371,177	0
Benson-Montin-Greer	La Plata	2	NW-30-32N-13W	319,414	0	302,340	0	621,754	0
Consolidated Oil & Gas	Robinson Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolidated Oil & Gas	Montoya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolidated Oil & Gas	Montoya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron Energy	Write State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
Delhi-Taylor	Atlantic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
Tenneco	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
Southland Royalty	Titt	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
Totals		31		5,293,695	21,781	4,428,332	24,545	9,722,027	46,326
Average				170,764	702	142,850	792	313,614	1,494

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
LARRY KEHOE
SECRETARY

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

June 4, 1982

Steve Palko
Southland Royalty Company
1000 Ft. Worth Club Building
Ft. Worth, Texas 76102

RE: NMOCD Case No. 7361,
Designation of Tight
Formation, Dakota Formation
(Basin-Dakota Field) San
Juan County, New Mexico

Dear Mr. Palko:

As per our telephone conversation Friday, June 4, 1982, Michael Boyle with the Federal Energy Regulatory Commission in Washington,D. C. requested to the New Mexico Oil Conservation Division the following supplemental information concerning Exhibit No. 13. (See attached copy.)

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2) is this reported oil production from wells that were stimulated

3) please submit actual production history from those wells having oil production

Please submit to this office three copies of the requested supplemental information.

If we may be of any assistance, please call. Thank you.

Sincerely,

Michael E. Stogner

Michael E. Stogner
Petroleum Engineer

MES/dp

cc: W. Perry Pearce
General Counsel
New Mexico Oil Conservation
Division
Santa Fe, NM 87501

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 13
CASE NO.__________

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator	Lease	Well No.	Location	Cumulative Production (1-1-80) Gas (MCF)	Cumulative Production (1-1-80) Oil (BBLS)	Remaining Reserves (1-1-80) Gas (MCF)	Remaining Reserves (1-1-80) Oil (BBLS)	Ultimate Reserves Gas (MCF)	Ultimate Reserves Oil (BBLS)
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Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
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Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
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Tenneco	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
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Totals		31		5,293,695	21,781	4,428,332	24,545	9,722,027	46,326
Average				170,764	702	142,850	792	313.614	1,494

Consolidated
Ex 1 thru 19
Complete
incl
affidavit

Consolidated Oil & Gas, Inc.

LINCOLN TOWER BUILDING
1860 LINCOLN STREET
DENVER, COLORADO 80295
(303) 861-5252

RECEIVED
JAN 27 1981
OIL CONSERVATION DIVISION
SANTA FE

Mr. Daniel S. Nutter
Oil Conservation Division
P.O. Box 2088
Santa Fe, NM 87501

Re: Case No. 7116

Dear Mr. Nutter:

Enclosed are additional exhibits and testimony in the above-referenced case. We've included four copies of each and a prepaid mailer for forwarding everything to the FERC.

Very truly yours,

CONSOLIDATED OIL & GAS, INC.

Lynn Teschendorf
Attorney

LHT/mek

JAMES B. COONEY, P.A.
ATTORNEYS AT LAW
811 WEST APACHE
P. O. BOX 268
FARMINGTON, NEW MEXICO 87401

JAMES B. COONEY (1908-1979)
RICHARD T. C. TULLY
RICHARD L. LEE

(505) 327-3388

December 31, 1980

Joe D. Ramey, Director
New Mexico Oil Conservation Division
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: Tom Bolack
Tommy Bolack #1 Well
Township 30 North, Range 12 West, NMPM
Section 1: S/2
Containing 320 acres, more or less
San Juan County, New Mexico

Dear Mr. Ramey:

In NMOCD Case No. 6993 held August 6, 1980, Tom Bolack requested an order pooling all of the mineral interests in the Dakota Formation underlying the above captioned lands. William R. Speer, Consulting Geologist, P. O. Box 255, Farmington, New Mexico 87401, was the expert witness testifying on behalf of Tom Bolack in this matter.

On September 10, 1980 the NMOCD issued Order No. R-6455 which pooled all mineral interests in the Dakota Formation underlying these lands in order to form a standard 320 acre gas spacing and proration unit to be dedicated to the Tommy Bolack #1 Well. This Order further provided, among other things, a 200% charge for the risk involved in drilling this well.

A review of the testimony of Mr. Speer in this matter shows that the current NGPA Section 103, "New Onshore Production Wells", natural gas prices for the Dakota Formation was not a sufficient economic incentive to drill the Tommy Bolack #1 Well. The Examiner for this hearing, Daniel S. Nutter, asked Mr. Speer the question of why the well was proposed to be drilled if the anticipated production from the Dakota Formation would result in a non-commercial well. Mr. Speer responded that this well was only being drilled because of the potential dual completion of this well with another formation besides the Dakota Formation.

Further, it was the professional opinion of Mr. Speer that if this well was capable of producing from only the Dakota Formation, then the well would not be drilled at the present time. As mentioned above, the NMOCD entertained this information when it ordered a 200% charge for the risk involved in drilling this well.

On December 30, 1980 a NMOCD Hearing was held for Case No. 7116. This case concerned the application of Southland Royalty Company for the designation of a "tight formation" in San Juan County, New Mexico for the Dakota Formation. At this hearing, Southland Royalty Company proposed the designation of the Dakota Formation underlying portions of Townships 31 and 32 North, Ranges 10, 11, 12, and 13 West, containing 93,860 acres, more or less, as a tight formation under the NGPA. The testimony by the witness for Southland Royalty Company did not testify as to the designation of the Dakota Formation for the above captioned lands, but did provide information on wells and lands located within one mile of this well. After the witness for Southland Royalty Company finished his testimony, Consolidated Oil and Gas Company, Inc. presented testimony for additional lands to be included within the application of Southland Royalty Company. The amendment of the application of Southland Royalty Company to add the additional acreage requested by Consolidated Oil and Gas was taken under advisement by the NMOCD Examiner during the hearing.

Due to the confusion of the current status of Southland Royalty Company's tight sands application and the request by Consolidated Oil and Gas Company, Inc. to add additional lands to this application, it is respectfully requested that Tom Bolack also be allowed an opportunity for designation of the Dakota Formation underlying the above captioned lands as a tight formation under the NGPA. As a further note, 120 acres of the 320 acres dedicated to the Tommy Bolack #1 Well for the Dakota Formation are owned by Southland Royalty Company under the Federal Oil and Gas Lease SF 077482.

Thank you in advance for your assistance and cooperation in this matter. Please advise if you need further information.

Sincerely,

Richard T.C. Tully

Richard T. C. Tully

RTCT:sak

cc: Honorable Tom Bolack
Route 3 South, Box 47
Farmington, New Mexico 87401

Tommy Bolack and Terry Bolack,
Co-Personal Representatives of the
Estate of Alice N. Bolack, Deceased
Route 3 South, Box 47
Farmington, New Mexico 87401

William R. Speer
Consulting Geologist
P. O. Box 255
Farmington, New Mexico 87401

Larry Van Ryan
Production Superintendent
Southland Royalty Company
Post Office Box 570
Farmington, New Mexico 87401

William F. Carr, Esq.
Campbell and Black, P.A.
P. O. Box 2208
Santa Fe, New Mexico 87501

Lynn Teschendorf, Attorney
Consolidated Oil & Gas Company, Inc.
Lincoln Tower Bldg.
1860 Lincoln Street
Denver, Colorado 80295

BEFORE THE
STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

In the matter of the application of
Southland Royalty Company for designation
of a tight formation, San Juan County,
New Mexico

Case No. 7116

AFFIDAVIT

I, FLOYD E. ELLISON, being first duly sworn, depose and state that:

Permeability Calculations

Exhibits 5, 6 and 7 show the permeability calculations for the Wilmerding 1-M in Section 10, T31N, R13W, Kline 1-M in Section 10, T31N, R13W and Senter 1-M in Section 24, T31N, R13W based on the flow tests previously submitted (which were witnessed by New Mexico Oil Conservation Division personnel). In all cases the permeability calculations using Darcy's flow equation show the in situ permeability to be well below 0.1 md.

Well Cost Estimate

Consolidated's drilling and completion well cost estimate for an average depth 7,000' single Dakota completion totals $475,400 (see Exhibit 19). These costs are based on our experience in drilling and completing a number of wells this past year in the immediate area. Several significant differences with the Southland Royalty cost estimate are:

1. Consolidated's use of $16/ft. vs. Southland's $14/ft. The $16/ft. figure is our most recent quoted price and corresponds with inquiries we have made of other operators' footage prices. We have a working interest in a well recently drilled in the area in which the operator was required to pay $19.51/ft.

2. Consolidated's average mud and water costs are well above those shown on the Southland estimate. Some mud and water costs have been as low as Southland's estimate, but we have experienced severe lost circulation in the Mesaverde, Gallup and/or Dakota zones in several wells which brings the average mud and water cost to our estimate.

3. The recent requirement by both the state and USGS to cement across the Ojo Alamo and circulate cement to surface requires additional DV tools and cement. Southland's cementing and cementing tools estimate is below the costs we have been experiencing in our most recent wells.

4. Completion Costs. Consolidated's completion procedure differs in several ways from Southland's. Consolidated has recently been including the tight lower Dakota in its completions because we believe enough additional reserves can be added in certain wells to justify the additional completion expense. A major cause of the increased expense is the necessity to perforate, stimulate, and clean up the upper and lower Dakota separately. The tight lower Dakota has an approximate 800 - 1,000# higher treatment and ISIP than does the upper Dakota

which makes it necessary to frac and clean up the zone before moving on to the upper Dakota completion. Consolidated has also been using nitrogen in its frac treatments to aid clean up but its use does add to stimulation costs.

Economics

Based on Consolidated Oil & Gas's required after tax economic criteria, Consolidated needs approximately 650 MMCF of gas reserves with Section 103 prices and 335 MMCF of gas reserves with 2 X 103 prices to justify drilling a single Dakota completion, as shown on Exhibit 8. These reserve requirements are considerably above what we used to justify our drilling program in the area this past year and above what Southland Royalty has indicated they need. The required larger reserves are the result of these major differences:

1. The majority of our wells this past year were dual completions with the Mesaverde reserves helping pay out the drilling and completion costs.

2. The drilling and completion costs have increased dramatically with the differences between Consolidated and Southland Royalty's estimates having been previously discussed.

3. The net interest (after deducting royalty interest and overriding royalty interest) on Consolidated operated properties in the area is 75.5% vs. Southland Royalty's indicated 86.5%. The majority of Consolidated's properties are 75% leases due to Consolidated having to give up an additional 12.5% ORR before it could farm-in the acreage and drill the original wells in the 1950's and 1960's. This is a major cut out of the income without any offsetting help on the expense side.

4. The required rate of return (ROR) after taxes for Consolidated is 20% vs. Southland Royalty's indicated 15%. Consolidated cannot justify less than a 20% ROR in the present money market when we pay over 20% for the money we borrow. Investors, including Consolidated, can receive more than 15% interest on CD's without assuming any risk so surely assuming risk is worth something above the 15% Southland proposed.

Exhibit 9 shows the assumptions used for our economic calculations and Exhibits 10, 11, 12 and 13 show the before and after taxes economics for 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves with 103 pricing and Exhibits 14, 15, 16, 17 and 18 show the before and after taxes economics for 200 MMCFG, 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves for 2 X 103 pricing.

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jose, Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producting formation which is about 5,900 feet below the deepest fresk water zone.

Exhibits 5 through 19 were prepared by me or under my direction and supervision.

Floyd E. Ellison, Jr.
Floyd E. Ellison, Jr.
Vice President - Operations

STATE OF COLORADO)
) ss
CITY AND COUNTY OF DENVER)

On this 22nd day of January, 1981, before me personally appeared Floyd E. Ellison, Jr., to me known to be the person described in and who executed the foregoing Affidavit before me, and who acknowledged to me that he executed it as his own free act and deed.

WITNESS my hand and seal on this day and year last above written.

Patricia G Burns
Notary Public

My Commission Expires:
My commission expires June 13, 1983

CONSOLIDATED OIL & GAS, INC.
Senter 1-M
NE/4 SE/4 24-T31N-R13W
San Juan County, New Mexico

Lower Dakota — Perforations 6898', 6902', 6906', 6910', 6914', 6918', 6934', 6938', 6942', 6946', 6950', 6954', & 6958', (13-.33" diameter perforations)

Acidized with 500 gallons 15% NE acid using 25 ball sealers. Balled off @ 3200#.

Swabbed well down to get acid back.

5/20-21/80 — Tefteller, Inc. ~~ran flow test~~ on Dakota perforations 6898'-6958'.

5/20/80	12:45 p.m.	2.73 MCF/D
	3:45 p.m.	1.91 MCF/D
	7:00 a.m.	1.91 MCF/D

Test witnessed by Frank Chavez and Rich Simmons of NMOCC, Tobby Tefteller and Len Alexander with Tefteller and Aubrey Prather with Consolidated Oil & Gas, Inc.

Upper Dakota — Perforations 6740', 6745', 6759', 6776', 6782', 6786', 6794', 6808', 6810', 6814', and 6816'.

Acidized with 500 gallons 15% NE acid using 22 ball sealers. Balled off @ 3500#.

Swabbed well down.

6/4-5/80 — Tefteller, Inc. ran flow test on Dakota perforations 6740'-6816'.

Flowed total 21 hours. Well stabilized @ approximately 52 MCF/D rate over last 16½ hours.

Test witnessed by Rich Simmons with NMOCC, Tefteller testers, and Barney Jones with Consolidated Oil & Gas, Inc.

no oil produced

would [illegible] w/ Darcy

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
COG EXHIBIT NO. 4
CASE NO. 7116

CONSOLIDATED OIL & GAS, INC.
Wilmerding 1-M
NE/4 NW/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota — Perforations 6788', 6798', 6828', 6830', 6833', 6838', 6841', and 6846', (8-.32" diameter perforations)

Acidized with 250 gallons 7½% NE acid using 16 ball sealers.

Swabbed well down.

9/11/80 — Flowed well through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.

Test witnessed by Charles Gholson with NMOCC and Barney Jones with Consolidated Oil & Gas, Inc.

Did not test Upper Dakota.

actually less than [illegible] MCF/day
w/ no acid
Lower Dak only
(much [illegible] in Upper Dak)

witness: Perm would calc to
less than 1 MD

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
COG EXHIBIT NO. 2
CASE NO. 7116

CONSOLIDATED OIL & GAS, INC.
Kline 1-M
NE/4 SE/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota	Perforations 6655', 6658', 6668', 6672', 6676', 6715', 6720', 6724', 6729', 6734', and 6736', (9-.29" holes)
	Acidized with 300 gallons 7½% NE acid using 21 ball sealers. Balled off @ 5000#.
	Swabbed down and recovered water and acid.
	Flowed well through Critical Prover using 1/8" orifice plate. Produced 5 hours with maximum rate of 12.85 MCF/D.
8/22/80	Test witnessed by Rich Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.
Upper Dakota	Perforations 6506', 6512', 6520', 6527', 6532', 6540', 6550', 6557', 6565', 6572', 6577', 6584', 6592', 6612', 6617', 6621', and 6629', (17 perforations .32" diameter)
	Acidized with 500 gallons 7½% NE acid with 30 ball sealers. Balled off @ 5500#.
	Swabbed well down.
	Flowed well 4 hours through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.
8/28/80	Test witnessed by Richard H. Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.

Would calc to [illegible] [illegible] MCFD

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
COG EXHIBIT NO. 3
CASE NO. 7110

CONSOLIDATED OIL & GAS, INC.
WILMERDING NO. 1M
NE/4 NW/4 10-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Data:

	Lower Dakota	Upper Dakota
Midperforations	6817'	6697'
Qg	To Small To Measure	Not Tested
h (log)	27'	57'

K (permeability)

Inadequate gas to compute flow rate and permeability (K) is much less than oil md.

EXHIBIT 5

CONSOLIDATED OIL & GAS, INC.
KLINE NO. 1M
NE/4 SE/4 10-31N-13W
BASIN DAKOTA FIELD

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6696'	6567'
Qg	12850 SCF (test)	Gas Too Small To Measure
h	38' feet (log)	
Pwf	38 Psia	
Pe	2592 Psia	
gg	.70	
T	186°-646°R	
re	1320 feet	
rw	0.02 feet	
Psc	668 Psia	
Tsc	392°Rankin	
Ug	.014 cp	
Z	0.91	

Where:

Og = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
gg = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing

rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$K = \frac{QgUgTZ\ \ln(.61re/rw)}{703h(Pe^2-Pwf^2)}$$

$$K = \frac{12850x.014x646x.91x\ln(.61x\frac{1320}{20})}{703x38x(2592^2-38^2)}$$

$$K = .0000049 \quad D$$

$$\underline{K = .0049 \quad md.}$$

EXHIBIT 6

CONSOLIDATED OIL & GAS, INC.
SENTER NO. 1M
NE/4 SE/4 24-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6928	6728
Qg Scf (test)	2730	52000
h feet (log)	58	51
Pwf Psia	20	32
Pe by analogy & tests	2658	2592
G_g typical gravity field gas	.70	.70
T^o calculated	186°F(646°R)	186°F(646°R)
re feet	1320	1320
rw feet	.20	.20
Psc Psia	668	668
Tsc °Rankin	392°R	392°R
Ug cps(calc.)	.014	.014
Z (calc)	.91	.91

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
gg = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing

rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$Qg = \frac{703Kh(Pe^2-Pf^2)}{UgTZ\ \ln(.61re/rw)} \quad \text{and } K = \frac{QgUgTZ\ \ln\ (.61re/rw)}{703h(Pe^2-Pwf^2)}$$

Lower Dakota

$$K = \frac{2730(.014)(646)(.91)\ln(.61x\frac{1320}{20})}{(703)(58)(2658^2-20^2)}$$

= .00000068 D

= 00068 md.

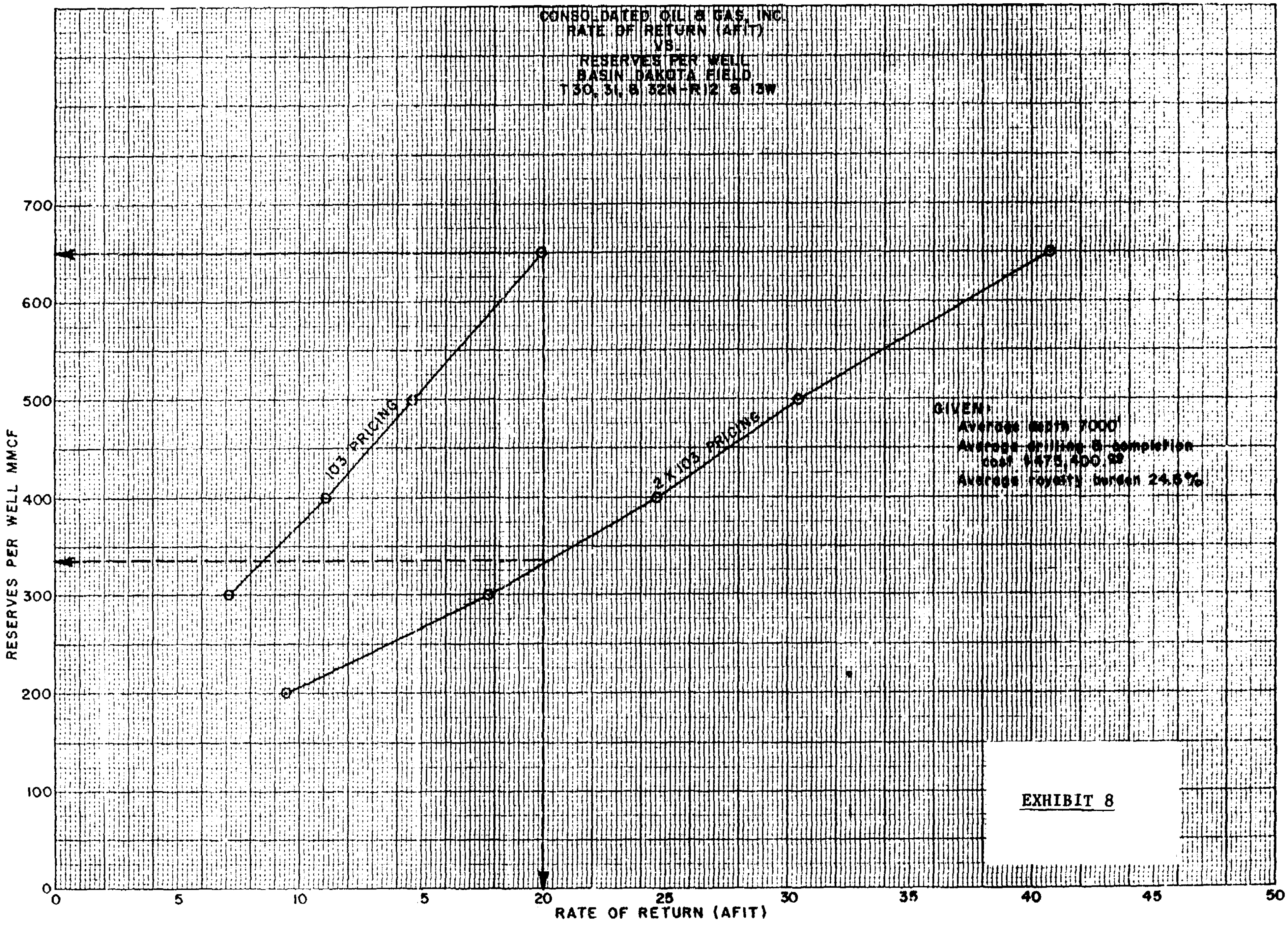
Upper Dakota

$$K = \frac{52000(.014)(646)(.91)\ln(.61x\frac{1320}{20})}{(703)(51)(2592^2-32^2)}$$

= .0000146 D

= .0146 md.

EXHIBIT 7



CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (AFIT)
VS.
RESERVES PER WELL
BASIN DAKOTA FIELD
T 30, 31, & 32N-R12 & 13W

GIVEN:
Average depth 7000'
Average drilling & completion cost $475,400.00
Average royalty burden 24.5%

EXHIBIT 8

CONSOLIDATED OIL & GAS, INC.

ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS

BASIN DAKOTA FIELD

SAN JUAN COUNTY, NEW MEXICO

Drilling and completion costs (including Tank Battery)	$475,400
Operating Costs $/mo	150
Depth	7000'
Consolidated Working Interest	100.00
Royalty Interest Typical to Consolidated Holdings	24.5
Initial Stabilized Production Rate(MCFD)	
200 MMCF Reserves	89
300 MMCF Reserves	150
400 MMCF Reserves	189
500 MMCF Reserves	232
650 MMCF Reserves	400
Liquid Yield (Bbls/MMCF)	3.85
Fully Adjusted Gas Price as of October 1, 1981 ($/Mcf)	$3.11
Maximum Gas Price ($/Mcf)	$10.42
Maximum Oil Price ($/Bbl)	$50.00
Rate of Price Escalation %	$7.00
Severance tax (%)	$8.00
Deregulation Tax Data, Base Oil Price	$14.11
Windfall Profit Tax Rate %	$30.00

EXHIBIT 9

```
TYPICAL WELL NO. 2                                                                                    DATE: 01/16/81.
BASIN DAKOTA                                                                                          TIME: 17.04.46.
SAN JUAN CO., NEW MEXICO                                                                              FILE: TYPW2
300 MMF PER WELL 103 PRICE                                                                            PROJ:  3
CONSOLIDATED OIL & GAS                  R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                     AS OF DATE :  1/ 1/1981

                                                                                                            20.000 PCT
 END  GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO    NET      NET OPER   NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES   BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$----  ----M$---- ----M$---- ----M$----

12-81       .052     13.500       .039     10.192     30.441    475.400      1.800    -446.759   -446.759   -449.344
12-82       .213     55.523       .161     41.920    133.991      0.         1.926     132.065   -314.694   -351.316
12-83       .151     39.166       .114     29.571    101.073      0.         2.061      99.012   -215.682   -291.132
12-84       .112     29.108       .085     21.976     80.197      0.         2.205      77.992   -137.690   -252.310
12-85       .087     22.484       .065     16.976     66.157      0.         2.359      63.798    -73.892   -226.306

12-86       .068     17.890       .052     13.507     56.177      0.         2.525      53.652    -20.240   -208.397
12-87       .056     14.574       .042     11.003     48.897      0.         2.701      46.196     25.956   -195.770
12-88       .047     12.101       .035      9.136     43.421      0.         2.891      40.530     66.486   -186.698
12-89       .039     10.209       .030      7.708     39.168      0.         3.092      36.076    102.562   -180.085
12-90       .034      8.728       .026      6.590     35.829      0.         3.310      32.517    135.081   -175.204

12-91       .029      7.547       .021      5.698     33.078      0.         3.540      29.533    164.619   -171.573
12-92       .025      6.592       .019      4.977     30.841      0.         3.600      27.241    191.860   -168.831
12-93       .022      5.806       .017      4.383     29.011      0.         3.600      25.411    217.271   -166.737
12-94       .020      5.153       .015      3.891     27.520      0.         3.600      23.920    241.191   -165.122
12-95       .018      4.605       .014      3.476     26.276      0.         3.600      22.676    263.867   -163.869

S TOT       .973    252.986       .735    191.004    782.077    475.400     42.810     263.867    263.867   -163.869

AFTER       .181     47.014       .136     35.496    336.646      0.        91.117     245.529    509.396   -159.661

TOTAL      1.154    300.000       .871    226.500   1118.723    475.400    133.927     509.396    509.396   -159.661


CUM.        0.         0.                 NET  OIL REVENUE      34.553          5 PCT    175.388  40 PCT    -297.050
                                          NET  GAS REVENUE    1084.170         10 PCT      7.351  50 PCT    -332.659
ULT.       1.154    300.000               NET PROD REVENUE       0.            15 PCT    -92.743  60 PCT    -358.345
                                                                               20 PCT   -159.661  80 PCT    -392.507
CUM NET INC/INV(1)     1.07               CUM NET PW/INV(1)      -.34          30 PCT   -244.674 100 PCT    -413.687
GROSS WELLS               1               LIFE (YEARS)          40.31
MONTHS 1ST YEAR          12               RATE OF RETURN,PCT    10.37
INITIAL W.I., PCT  100.0000               INITIAL N.I., PCT     75.5000
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EXHIBIT 10

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TYPICAL WELL NO. 2                                                                                   DATE: 01/16/81.
BASIN DAKOTA                                                                                         TIME: 17.20.11.
SAN JUAN CO., NEW MEXICO                                                                             FILE: TYPW2
300 MMF PER WELL 103 PRICE                                                                           PROJ:  3
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                               AS OF DATE:  1/ 1/1981

-END-      NET       NET     REVENUE    OPER.     NET      CAPITAL                          INCOME    CASH      CUM.
MO-YR      OIL       GAS     TO INT.    EXPENSE   INCOME   INVEST.      DEPR.    DEPL.      TAX      FLOW      NET PW
-----      MB-----   MMF-----  M$-----  M$-----   M$-----  M$-----     M$---    M$----     M$----   M$-----   M$------

12-81      .039     10.192    30.441     1.800    28.641   475.400     52.965     0.       -61.834  -384.924  -393.293
12-82      .161     41.920   133.991     1.926   132.065     0.        45.401     0.        41.599    90.466  -326.142
12-83      .114     29.571   101.073     2.061    99.012     0.        38.918     0.        28.845    70.167  -283.492
12-84      .085     21.976    80.197     2.205    77.992     0.        33.360     0.        21.423    56.569  -255.334
12-85      .065     16.976    66.157     2.359    63.798     0.        28.597     0.        16.897    46.901  -236.217

12-86      .052     13.507    56.177     2.525    53.652     0.        24.513     0.        13.987    39.665  -222.977
12-87      .042     11.003    48.897     2.701    46.196     0.        21.013     0.        12.088    34.108  -213.654
12-88      .035      9.136    43.421     2.891    40.530     0.        18.012     0.        10.809    29.721  -207.001
12-89      .030      7.708    39.168     3.092    36.076     0.        15.440     0.         9.905    26.171  -202.204
12-90      .026      6.590    35.829     3.310    32.519     0.        13.235     0.         9.256    23.263  -198.712

12-91      .021      5.698    33.078     3.540    29.538     0.        11.345     0.         8.733    20.805  -196.155
12-92      .019      4.977    30.841     3.600    27.241     0.         9.725     0.         8.408    18.833  -194.259
12-93      .017      4.383    29.011     3.600    25.411     0.         8.336     0.         8.196    17.215  -192.840
12-94      .015      3.891    27.520     3.600    23.920     0.         7.146     0.         8.052    15.868  -191.769
12-95      .014      3.476    26.276     3.600    22.676     0.         6.125     0.         7.944    14.732  -190.955

S TOT      .735    191.004   782.077    42.810   739.267   475.400    334.130     0.       144.308   119.561  -190.955

AFTER      .136     35.496   336.646    91.117   245.529     0.        36.770     0.       100.205   145.325  -188.384

TOTAL      .871    226.500  1118.723   133.927   984.796   475.400    370.900     0.       244.513   264.886  -188.384

RECAP
                              GROSS        W.I.        NET                                                DIS    PW OF NET
 INTEREST FRACTION         1.000000    1.000000    .755000        LIFE (YEARS)              40.31          PCT       M$
 OIL RESERVES,MB              1.154       1.154       .871        GROSS OIL WELLS            0.             ---   ---------
 GAS RESERVES,MMCF          300.000     300.000    226.500        GROSS GAS WELLS            1.000           5      46.322
 PRODUCTS                     0.          0.         0.           RATE OF RETURN,PCT         7.01           10     -68.754
 REVENUE,M$                1617.726    1617.726   1118.723        DISCOUNT RATE,PCT         20.0            15    -139.728
 OPERATING EXPENSE,M$       133.927     133.927    133.927        PAYOUT YEARS               8.66           20    -188.385
 TANGIBLES,M$               370.900     370.900    370.900                                                  30    -251.770
 INTANGIBLES,M$             104.500     104.500    104.500                                                  40    -291.882
                                                                                                            50    -319.812
 INITIAL OIL PRICE ($/B)                  44.23               W.I. BEFORE PAYOUT,PCT 100.00                 70    -356.357
 INITIAL GAS PRICE ($/M)                  3.1100              W.I. AFTER  PAYOUT,PCT 100.00                100    -387.734
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TYPICAL WELL NO. 1                                                                                       DATE: 01/16/81.
BASIN DAKOTA                                                                                             TIME: 14.24.22.
SAN JUAN CO., NEW MEXICO                                                                                 FILE: TYPW
400 MMF PER WELL 103 PRICE                                                                               PROJ:  1
CONSOLIDATED OIL & GAS                  R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                    AS OF DATE :  1/ 1/1981

                                                                                                                 20.000 PCT
 END  GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET      NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81       .065     16.860       .049     12.729     38.019    475.400      1.800   -439.181   -439.181   -442.475
12-82       .284     73.944       .214     55.828    178.457         0.      1.926    176.531   -262.650   -311.441
12-83       .200     51.934       .151     39.210    134.016         0.      2.061    131.955   -130.695   -231.233
12-84       .148     38.477       .112     29.050    106.009         0.      2.205    103.804    -26.891   -179.563
12-85       .114     29.651       .086     22.387     87.224         0.      2.359     84.865     57.974   -144.971

12-86       .091     23.550       .069     17.780     73.994         0.      2.525     71.469    129.443   -121.115
12-87       .073     19.155       .055     14.462     64.248         0.      2.701     61.547    190.990   -104.292
12-88       .061     15.886       .046     11.994     56.981         0.      2.891     54.090    245.080    -92.185
12-89       .052     13.388       .039     10.108     51.393         0.      3.092     48.301    293.381    -83.331
12-90       .044     11.437       .034      8.635     46.930         0.      3.310     43.620    337.001    -76.784

12-91       .038      9.882       .028      7.461     43.313         0.      3.540     39.773    376.774    -71.895
12-92       .033      8.625       .025      6.512     40.363         0.      3.600     36.763    413.537    -68.195
12-93       .029      7.593       .022      5.732     37.948         0.      3.600     34.348    447.885    -65.363
12-94       .026      6.737       .020      5.087     35.975         0.      3.600     32.375    480.260    -63.178
12-95       .023      6.016       .017      4.542     34.309         0.      3.600     30.709    510.769    -61.481

S TOT      1.281    333.135       .967    251.517   1029.179    475.400     42.810    510.969    510.769    -61.481

AFTER       .257     66.865       .194     50.483    479.930         0.    113.385    366.545    877.514    -55.715

TOTAL      1.538    400.000      1.161    302.000   1509.109    475.400    156.195    877.514    877.514    -55.715


CUM.          0.         0.             NET  OIL REVENUE      46.139         5 PCT     399.260  40 PCT   -239.118
                                        NET  GAS REVENUE    1462.970        10 PCT     168.950  50 PCT   -286.561
ULT.       1.538    400.000             NET PROD REVENUE          0.        15 PCT      33.973  60 PCT   -320.769
                                                                            20 PCT     -55.715  80 PCT   -366.248
CUM NET INC/INV(1)     1.85             CUM NET PW/INV(1)       -.12        30 PCT    -169.281 100 PCT   -394.431
GROSS WELLS               1             LIFE (YEARS)           46.50
MONTHS 1ST YEAR          12             RATE OF RETURN,PCT     16.89
INITIAL W.I., PCT  100.0000             INITIAL N.I., PCT    75.5000
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EXHIBIT 11

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TYPICAL WELL NO. 1                                                                                DATE: 01/16/81.
BASIN DAKOTA                                                                                      TIME: 14.34.00.
SAN JUAN CO., NEW MEXICO                                                                          FILE: TYPW
400 MMF PER WELL 103 PRICE                                                                        PROJ:  1
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                            AS OF DATE:  1/ 1/1981

-END-      NET        NET        REVENUE   OPER.     NET       CAPITAL                        INCOME    CASH      CUM.
MO-YR      OIL        GAS        TO INT.   EXPENSE   INCOME    INVEST.    DEPR.     DEPL.     TAX       FLOW      NET PW
-----      MB-----    MMF-----   M$-----   M$-----   M$-----   M$-----    M$---     M$----    M$----    M$-----   M$------


12-81          .049     12.729    38.019     1.800    36.219   475.400    52.965    0.       -55.772  -383.408  -391.919
12-82          .214     55.828   178.457     1.926   176.531     0.       45.401    0.        60.320   116.211  -305.659
12-83          .151     39.210   134.016     2.061   131.955     0.       38.918    0.        42.797    89.158  -251.465
12-84          .112     29.050   106.009     2.205   103.804     0.       33.360    0.        32.404    71.400  -215.925
12-85          .086     22.387    87.224     2.359    84.865     0.       28.597    0.        25.883    58.982  -191.883

12-86          .069     17.780    73.994     2.525    71.469     0.       24.513    0.        21.600    49.869  -175.237
12-87          .055     14.462    64.248     2.701    61.547     0.       21.013    0.        18.646    42.901  -163.511
12-88          .046     11.994    56.981     2.891    54.090     0.       18.012    0.        16.596    37.494  -155.118
12-89          .039     10.108    51.393     3.092    48.301     0.       15.440    0.        15.116    33.185  -149.035
12-90          .034      8.635    46.930     3.310    43.620     0.       13.235    0.        13.977    29.643  -144.586

12-91          .028      7.461    43.313     3.540    39.773     0.       11.345    0.        13.077    26.696  -141.304
12-92          .025      6.512    40.363     3.600    36.763     0.        9.725    0.        12.437    24.326  -138.856
12-93          .022      5.732    37.948     3.600    34.348     0.        8.336    0.        11.965    22.383  -137.011
12-94          .020      5.087    35.975     3.600    32.375     0.        7.146    0.        11.605    20.770  -135.609
12-95          .017      4.542    34.309     3.600    30.709     0.        6.125    0.        11.308    19.401  -134.537

S TOT          .967    251.517  1029.179    42.810   986.369   475.400   334.130    0.       251.959   259.009  -134.537

AFTER          .194     50.483   479.930   113.385   366.545     0.       36.770    0.       151.696   214.848  -131.057

TOTAL         1.161    302.000  1509.109   156.195  1352.914   475.400   370.900    0.       403.655   473.858  -131.057

RECAP                                                                                            DIS    PW OF NET
                          GROSS       W.I.        NET                                            PCT      M$
 INTEREST FRACTION     1.000000   1.000000    .755000          LIFE (YEARS)          46.50      ---    ---------
 OIL RESERVES,MB          1.538      1.538      1.161          GROSS OIL WELLS       0.
 GAS RESERVES,MMCF      400.000    400.000    302.000          GROSS GAS WELLS       1.000        5     172.562
 PRODUCTS                0.         0.         0.              RATE OF RETURN,PCT    11.19       10      21.671
 REVENUE,M$            2182.032   2182.032   1509.109          DISCOUNT RATE,PCT      20.0       15     -69.346
 OPERATING EXPENSE,M$   156.195    156.195    156.195          PAYOUT YEARS            5.96      20    -131.058
 TANGIBLES,M$           370.900    370.900    370.900                                            30    -210.762
 INTANGIBLES,M$         104.500    104.500    104.500                                            40    -260.814
                                                                                                 50    -295.455
 INITIAL OIL PRICE ($/B)             44.24                     W.I. BEFORE PAYOUT,PCT 100.00     70    -340.402
 INITIAL GAS PRICE ($/M)             3.1100                    W.I. AFTER  PAYOUT,PCT 100.00    100    -378.417
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TYPICAL WELL NO. 4                                                                                      DATE: 01/16/81.
BASIN DAKOTA                                                                                            TIME: 17.04.56.
SAN JUAN CO., NEW MEXICO                                                                                FILE: TYPW2
500 MMF PER WELL 103 PRICE                                                                              PROJ:  6
CONSOLIDATED OIL & GAS                   R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                   AS OF DATE :  1/ 1/1981

                                                                                                                 20.000 PCT
 END   GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET     NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81       .080     20.880       .060     15.764     47.072    475.400      1.800   -430.128   -430.128   -434.269
12-82       .355     92.219       .268     69.626    222.584     0.          1.926    220.658   -209.470   -270.480
12-83       .248     64.577       .188     48.755    166.622     0.          2.061    164.561    -44.909   -170.453
12-84       .184     47.743       .139     36.046    131.548     0.          2.205    129.243     84.434   -106.071
12-85       .141     36.733       .106     27.734    108.051     0.          2.359    105.692    190.126    -62.990

12-86       .112     29.138       .085     21.999     91.533     0.          2.525     89.008    279.134    -33.280
12-87       .091     23.677       .068     17.876     79.439     0.          2.701     76.738    355.872    -12.304
12-88       .076     19.620       .058     14.813     70.395     0.          2.891     67.504    423.376      2.806
12-89       .063     16.524       .047     12.476     63.391     0.          3.092     60.299    483.675     13.858
12-90       .055     14.106       .042     10.650     57.908     0.          3.310     54.598    538.273     22.054

12-91       .047     12.184       .035      9.199     53.407     0.          3.540     49.867    588.140     28.183
12-92       .040     10.629       .030      8.025     49.719     0.          3.600     46.119    634.259     32.825
12-93       .036      9.354       .028      7.062     46.759     0.          3.600     43.159    677.418     36.383
12-94       .032      8.295       .024      6.263     44.293     0.          3.600     40.693    718.111     39.129
12-95       .029      7.407       .022      5.592     42.266     0.          3.600     38.666    756.777     41.267

S TOT      1.589    413.086      1.200    311.880   1274.987    475.400     42.810    756.777    756.777     41.267

AFTER       .334     86.914       .252     65.620    624.729     0.        132.842    491.887   1248.664     48.560

TOTAL      1.923    500.000      1.452    377.500   1899.716    475.400    175.652   1248.664   1248.664     48.560


CUM.        0.         0.                  NET  OIL REVENUE      57.749        5 PCT    622.058  40 PCT   -180.457
                                           NET  GAS REVENUE    1841.967       10 PCT    330.138  50 PCT   -239.670
ULT.       1.923    500.000                NET PROD REVENUE       0.          15 PCT    160.754  60 PCT   -282.368
                                                                              20 PCT     48.560  80 PCT   -339.154
CUM NET INC/INV(1)     2.63                CUM NET PW/INV(1)       .10        30 PCT    -93.289 100 PCT   -374.362
GROSS WELLS               1                LIFE (YEARS)          51.90
MONTHS 1ST YEAR          12                RATE OF RETURN,PCT    23.01
INITIAL W.I., PCT  100.0000                INITIAL N.I., PCT     75.5000
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EXHIBIT 12

```
TYPICAL WELL NO. 4                                                                                    DATE: 01/16/81.
BASIN DAKOTA                                                                                          TIME: 17.20.23.
SAN JUAN CO., NEW MEXICO                                                                              FILE: TYPW2
500 MMF PER WELL 103 PRICE                                                                            PROJ:  6
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                                  AS OF DATE:  1/ 1/1981

-END-     NET       NET       REVENUE    OPER.     NET       CAPITAL                       INCOME     CASH      CUM.
MO-YR     OIL       GAS       TO INT.    EXPENSE   INCOME    INVEST.    DEPR.    DEPL.     TAX        FLOW      NET PW
-----     MB-----   MMF-----  M$-----    M$-----   M$-----   M$-----    M$---    M$----    M$----     M$-----   M$------

12-81      .060     15.764     47.072     1.800     45.272   475.400   52.965     0.       -53.851   -376.276   -385.454
12-82      .268     69.626    222.584     1.926    220.658     0.      45.401     0.        84.123    136.535   -284.108
12-83      .188     48.755    166.622     2.061    164.561     0.      38.918     0.        60.309    104.252   -230.739
12-84      .139     36.046    131.548     2.205    129.343     0.      33.360     0.        46.072     83.271   -179.290
12-85      .106     27.734    108.051     2.359    105.692     0.      28.597     0.        37.006     68.686   -151.293

12-86      .085     21.999     91.533     2.525     89.008     0.      24.513     0.        30.958     58.050   -131.916
12-87      .068     17.876     79.439     2.701     76.738     0.      21.013     0.        26.748     49.990   -118.252
12-88      .058     14.813     70.395     2.891     67.504     0.      18.012     0.        23.756     43.748   -108.459
12-89      .047     12.476     63.391     3.092     60.299     0.      15.440     0.        21.532     38.767   -101.354
12-90      .042     10.650     57.908     3.310     54.598     0.      13.235     0.        19.854     34.744    -96.138

12-91      .035      9.199     53.407     3.540     49.867     0.      11.345     0.        18.491     31.376    -92.282
12-92      .030      8.025     49.719     3.600     46.119     0.       9.725     0.        17.469     28.650    -89.398
12-93      .028      7.062     46.759     3.600     43.159     0.       8.326     0.        16.715     26.444    -87.218
12-94      .024      6.263     44.293     3.600     40.693     0.       7.146     0.        16.103     24.590    -85.558
12-95      .022      5.592     42.266     3.600     38.666     0.       6.125     0.        15.619     23.047    -84.284

S TOT     1.200    311.880   1274.987    42.810   1232.177   475.400  334.130     0.       380.904    375.875    -84.284

AFTER      .252     65.620    624.729   132.842    491.887     0.      36.770     0.       218.456    273.431    -30.110

TOTAL     1.452    377.500   1899.716   175.652   1724.064   475.400  370.900     0.       599.360    649.305    -30.110

RECAP
                            GROSS       W.I.       NET                                                DIS    PW OF NET
 INTEREST FRACTION       1.000000   1.000000   .755000        LIFE (YEARS)             51.90         PCT       M$
 OIL RESERVES,MB            1.923      1.923     1.452        GROSS OIL WELLS           0.           ---    ---------
 GAS RESERVES,MMCF        500.000    500.000   377.500        GROSS GAS WELLS           1.000          5     278.539
 PRODUCTS                   0.         0.        0.           RATE OF RETURN,PCT       14.63          10      99.079
 REVENUE,M$              2746.654   2746.654  1899.716        DISCOUNT RATE,PCT        20.0           15      -7.914
 OPERATING EXPENSE,M$     175.652    175.652   175.652        PAYOUT YEARS              4.76          20     -80.111
 TANGIBLES,M$             370.900    370.900   370.900                                                30    -173.050
 INTANGIBLES,M$           104.500    104.500   104.500                                                40    -231.254
                                                                                                      50    -271.458
 INITIAL OIL PRICE ($/B)               44.24                  W.I. BEFORE PAYOUT,PCT 100.00           70    -323.487
 INITIAL GAS PRICE ($/M)               3.1100                 W.I. AFTER  PAYOUT,PCT 100.00          100    -367.285
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TYPICAL WELL NO. 5                                                                                         DATE: 01/19/81.
BASIN DAKOTA                                                                                               TIME: 15.51.31.
SAN JUAN CO., NEW MEXICO                                                                                   FILE: TYPW3
650 MMF PER WELL 103 PRICE                                                                                 PROJ:  3
CONSOLIDATED OIL & GAS                  R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                   AS OF DATE :  1/ 1/1981

                                                                                                                      20.000 PCT
 END   GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET     NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81        .138     36.000       .104     27.180     81.160    475.400      1.800   -396.040   -396.040   -403.370
12-82        .435    113.027       .329     85.335    272.783      0.         1.926    270.857   -125.183   -202.320
12-83        .309     80.174       .233     60.532    206.897      0.         2.061    204.836     79.653    -77.812
12-84        .230     59.826       .174     45.168    164.825      0.         2.205    162.620    242.273      3.133
12-85        .178     46.353       .134     34.997    136.350      0.         2.359    133.991    376.264     57.750

12-86        .142     36.970       .107     27.912    116.134      0.         2.525    113.609    489.873     95.672
12-87        .116     30.175       .088     22.782    101.241      0.         2.701     98.540    588.413    122.606
12-88        .097     25.095       .073     18.947     90.032      0.         2.891     87.141    675.554    142.112
12-89        .081     21.198       .061     16.005     81.329      0.         3.092     78.237    753.791    156.452
12-90        .070     18.144       .053     13.698     74.458      0.         3.310     71.148    824.939    167.132

12-91        .060     15.706       .045     11.858     68.826      0.         3.540     65.286    890.225    175.157
12-92        .053     13.727       .040     10.364     64.256      0.         3.600     60.656    950.881    181.262
12-93        .047     12.101       .036      9.136     60.506      0.         3.600     56.906   1007.787    185.953
12-94        .041     10.748       .031      8.115     57.375      0.         3.600     53.775   1061.562    189.583
12-95        .037      9.609       .028      7.255     54.809      0.         3.600     51.209   1112.771    192.413

S TOT       2.034    528.853      1.536    399.284   1630.981    475.400     42.810   1112.771   1112.771    192.413

AFTER        .466    121.147       .351     91.466    872.308      0.       162.516    709.792   1822.563    202.173

TOTAL       2.500    650.000      1.887    490.750   2503.289    475.400    205.326   1822.563   1822.563    202.173

CUM.        0.          0.                NET  OIL REVENUE       75.155          5 PCT     950.746  40 PCT    -89.618
                                          NET  GAS REVENUE     2428.134         10 PCT     565.769  50 PCT   -164.696
ULT.        2.500    650.000              NET PROD REVENUE        0.            15 PCT     346.324  60 PCT   -218.834
                                                                                20 PCT     202.173  80 PCT   -290.984
CUM NET INC/INV(1)      3.83              CUM NET PW/INV(1)        .43          30 PCT      21.109 100 PCT   -335.965
GROSS WELLS                1              LIFE (YEARS)           60.14
MONTHS 1ST YEAR           12              RATE OF RETURN,PCT     31.72
INITIAL W.I., PCT   100.0000              INITIAL N.I., PCT     75.5000
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EXHIBIT 13

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TYPICAL WELL NO. 5                                                                                         DATE: 01/19/81.
BASIN DAKOTA                                                                                               TIME: 15.58.58.
SAN JUAN CO., NEW MEXICO                                                                                   FILE: TYPW3
650 MMF PER WELL 103 PRICE                                                                                 PROJ:  8
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                                AS OF DATE:  1/ 1/1981

-END-      NET        NET        REVENUE    OPER.      NET        CAPITAL                          INCOME     CASH       CUM.
MO-YR      OIL        GAS        TO INT.    EXPENSE    INCOME     INVEST.    DEPR.     DEPL.      TAX        FLOW       NET PW
-----      MB-----    MMF-----   M$-----    M$-----    M$-----    M$-----    M$---     M$----     M$----     M$-----    M$------


12-81         .104     27.180     81.160      1.800     79.360    475.400    52.965     0.        -37.489   -358.550   -369.387
12-82         .329     85.335    272.783      1.926    270.857      0.       45.401     0.        108.219    162.638   -248.665
12-83         .233     60.532    206.897      2.061    204.836      0.       38.918     0.         79.641    125.195   -172.566
12-84         .174     45.168    164.825      2.205    162.620      0.       33.360     0.         62.045    100.575   -122.504
12-85         .134     34.997    136.350      2.359    133.991      0.       28.597     0.         50.589     83.402    -88.508

12-86         .107     27.912    116.134      2.525    113.609      0.       24.513     0.         42.766     70.843    -64.861
12-87         .088     22.782    101.241      2.701     98.540      0.       21.013     0.         37.213     61.327    -48.098
12-88         .073     18.947     90.032      2.891     87.141      0.       18.012     0.         33.182     53.959    -36.020
12-89         .061     16.005     81.329      3.092     78.237      0.       15.440     0.         30.143     48.094    -27.205
12-90         .053     13.698     74.458      3.310     71.148      0.       13.235     0.         27.798     43.350    -20.698

12-91         .045     11.858     68.826      3.540     65.286      0.       11.345     0.         25.892     39.394    -15.855
12-92         .040     10.364     64.256      3.600     60.656      0.        9.725     0.         24.447     36.209    -12.211
12-93         .036      9.136     60.506      3.600     56.906      0.        8.336     0.         23.313     33.593     -9.442
12-94         .031      8.115     57.375      3.600     53.775      0.        7.146     0.         22.382     31.393     -7.323
12-95         .028      7.255     54.809      3.600     51.209      0.        6.125     0.         21.640     29.569     -5.688

S TOT        1.536    399.284   1630.981     42.810   1588.171    475.400   334.130     0.        551.781    560.991     -5.688

AFTER         .351     91.466    872.308    162.516    709.792      0.       36.770     0.        323.051    386.741      -.231

TOTAL        1.887    490.750   2503.289    205.326   2297.963    475.400   370.900     0.        874.832    947.733      -.231

RECAP
                            GROSS       W.I.        NET                                                   DIS     PW OF NET
 INTEREST FRACTION       1.000000   1.000000    .755000           LIFE (YEARS)              60.14         PCT        M$
 OIL RESERVES,MB            2.500      2.500      1.887           GROSS OIL WELLS           0.            ---     ---------
 GAS RESERVES,MMCF        650.000    650.000    490.750           GROSS GAS WELLS           1.000           5     449.427
 PRODUCTS                  0.         0.         0.               RATE OF RETURN,PCT        19.99          10     221.599
 REVENUE,M$              3618.829   3618.829   2503.289           DISCOUNT RATE,PCT          20.0          15      88.581
 OPERATING EXPENSE,M$     205.326    205.326    205.326           PAYOUT YEARS               3.70          20       -.232
 TANGIBLES,M$             370.900    370.900    370.900                                                    30    -113.563
 INTANGIBLES,M$           104.500    104.500    104.500                                                    40    -184.017
                                                                                                           50    -232.472
 INITIAL OIL PRICE ($/B)               44.24                      W.I. BEFORE PAYOUT,PCT 100.00            70    -294.939
 INITIAL GAS PRICE ($/M)              3.1100                      W.I. AFTER  PAYOUT,PCT 100.00           100    -347.319
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TYPICAL WELL NO. 3                                                                                    DATE: 01/16/81.
BASIN DAKOTA                                                                                          TIME: 17.04.53.
SAN JUAN CO., NEW MEXICO                                                                              FILE: TYFW2
200 MMF PER WELL 2 X 103 PRICE                                                                        PROJ:  5
CONSOLIDATED OIL & GAS              R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                             AS OF DATE :  1/ 1/1981

                                                                                                   20.000 PCT
 END  GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET     NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST    INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81       .031      8.010       .023      6.048     35.369    475.400      1.800   -441.831   -441.831   -444.877
12-82       .142     37.064       .108     27.983    175.112         0.      1.926    173.186   -268.645   -316.326
12-83       .101     26.041       .076     19.661    131.625         0.      2.061    129.564   -139.081   -237.571
12-84       .074     19.297       .056     14.569    104.225         0.      2.205    102.020    -37.061   -186.790
12-85       .057     14.874       .043     11.230     85.867         0.      2.359     83.508     46.447   -152.751

12-86       .045     11.814       .034      8.919     72.894         0.      2.525     70.369    116.816   -129.262
12-87       .037      9.611       .028      7.257     63.406         0.      2.701     60.705    177.521   -112.669
12-88       .031      7.971       .023      6.018     56.253         0.      2.891     53.362    230.883   -100.725
12-89       .026      6.719       .020      5.073     49.480         0.      3.092     46.388    277.271    -92.222
12-90       .022      5.739       .016      4.333     42.292         0.      3.310     38.982    316.253    -86.370

12-91       .019      4.960       .015      3.744     36.559         0.      3.540     33.019    349.272    -82.312
12-92       .017      4.329       .013      3.269     31.923         0.      3.600     28.323    377.595    -79.461
12-93       .014      3.812       .010      2.878     28.076         0.      3.600     24.476    402.071    -77.443
12-94       .013      3.381       .010      2.553     24.922         0.      3.600     21.322    423.393    -76.004
12-95       .012      3.020       .009      2.280     22.275         0.      3.600     18.675    442.068    -74.972

S TOT       .641    166.642       .484    125.815    960.278    475.400     42.810    442.068    442.068    -74.972

AFTER       .128     33.358       .097     25.185    245.882         0.    111.483    134.399    576.467    -72.272

TOTAL       .769    200.000       .581    151.000   1206.160    475.400    154.293    576.467    576.467    -72.272


CUM.       0.          0.                  NET  OIL REVENUE      23.077         5 PCT     288.747  40 PCT   -245.532
                                           NET  GAS REVENUE    1183.083        10 PCT     119.299  50 PCT   -291.713
ULT.        .769    200.000                NET PROD REVENUE          0.        15 PCT       7.384  60 PCT   -325.139
                                                                               20 PCT     -72.272  80 PCT   -369.629
CUM NET INC/INV(1)     1.21                CUM NET PW/INV(1)       -.15        30 PCT    -178.295 100 PCT   -397.181
GROSS WELLS               1                LIFE (YEARS)           45.97
MONTHS 1ST YEAR          12                RATE OF RETURN,PCT     15.46
INITIAL W.I., PCT  100.0000                INITIAL N.I., PCT    75.5000
                                                                                                    EXHIBIT 14
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TYPICAL WELL NO. 3                                                                                    DATE: 01/16/81.
BASIN DAKOTA                                                                                          TIME: 17.20.19.
SAN JUAN CO., NEW MEXICO                                                                              FILE: TYPW2
200 MMF PER WELL 2 X 103 PRICE                                                                        PROJ:  5
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                                AS OF DATE:  1/ 1/1981

-END-     NET       NET       REVENUE   OPER.     NET       CAPITAL                           INCOME    CASH      CUM.
MO-YR     OIL       GAS       TO INT.   EXPENSE   INCOME    INVEST.   DEPR.     DEPL.     TAX       FLOW      NET PW
-----     MB-----   MMF-----  M$-----   M$-----   M$-----   M$-----   M$---     M$----    M$----    M$-----   M$------

12-81        .023     6.048    35.369     1.800    33.569   475.400    52.965     0.       -59.469  -382.361  -390.970
12-82        .108    27.983   175.112     1.926   173.186     0.       45.401     0.        61.337   111.849  -307.948
12-83        .076    19.661   131.625     2.061   129.564     0.       38.918     0.        43.510    86.054  -255.640
12-84        .056    14.569   104.225     2.205   102.020     0.       33.360     0.        32.957    69.063  -221.263
12-85        .043    11.230    85.867     2.359    83.508     0.       28.597     0.        26.357    57.151  -197.968

12-86        .034     8.919    72.894     2.525    70.369     0.       24.513     0.        22.011    48.358  -181.827
12-87        .028     7.257    63.406     2.701    60.705     0.       21.013     0.        19.052    41.653  -170.441
12-88        .023     6.018    56.253     2.891    53.362     0.       18.012     0.        16.968    36.394  -162.295
12-89        .020     5.073    49.480     3.092    46.388     0.       15.440     0.        14.855    31.533  -156.515
12-90        .016     4.333    42.292     3.310    38.982     0.       13.235     0.        12.359    26.623  -152.519

12-91        .015     3.744    36.559     3.540    33.019     0.       11.345     0.        10.403    22.616  -149.739
12-92        .013     3.269    31.923     3.600    28.323     0.        9.725     0.         8.927    19.396  -147.787
12-93        .010     2.878    28.076     3.600    24.476     0.        8.336     0.         7.747    16.729  -146.408
12-94        .010     2.553    24.922     3.600    21.322     0.        7.146     0.         6.805    14.517  -145.428
12-95        .009     2.280    22.275     3.600    18.675     0.        6.125     0.         6.024    12.651  -144.729

S TOT        .484   125.815   960.278    42.810   917.468   475.400   334.130     0.       229.843   212.226  -144.729

AFTER        .097    25.185   245.882   111.483   134.399     0.       36.770     0.        46.862    87.537  -142.942

TOTAL        .581   151.000  1206.160   154.293  1051.867   475.400   370.900     0.       276.705   299.763  -142.942

RECAP
                          GROSS      W.I.       NET                                                 DIS    PW OF NET
 INTEREST FRACTION     1.000000   1.000000   .755000          LIFE (YEARS)             45.97        PCT       M$
 OIL RESERVES,MB           .769       .769      .581          GROSS OIL WELLS          0.           ---    ---------
 GAS RESERVES,MMCF      200.000    200.000   151.000          GROSS GAS WELLS          1.000          5    105.241
 PRODUCTS                 0.         0.        0.             RATE OF RETURN,PCT       9.54          10    -10.550
 REVENUE,M$            1741.181   1741.181  1206.160          DISCOUNT RATE,PCT       20.0           15    -87.665
 OPERATING EXPENSE,M$   154.293    154.293   154.293          PAYOUT YEARS             6.24          20   -142.943
 TANGIBLES,M$           370.900    370.900   370.900                                                 30   -217.253
 INTANGIBLES,M$         104.500    104.500   104.500                                                 40   -265.093
                                                                                                     50   -298.521
 INITIAL OIL PRICE ($/B)            44.25                     W.I. BEFORE PAYOUT,PCT 100.00          70   -342.122
 INITIAL GAS PRICE ($/M)            6.2200                    W.I. AFTER  PAYOUT,PCT 100.00         100   -379.151
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TYPICAL WELL NO. 2                                                                                       DATE: 01/16/81.
BASIN DAKOTA                                                                                             TIME: 17.04.49.
SAN JUAN CO., NEW MEXICO                                                                                 FILE: TYPW2
300 MMF PER WELL 2 X 103 PRICE                                                                           PROJ:  4
CONSOLIDATED OIL & GAS                   R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                   AS OF DATE :  1/ 1/1981

                                                                                                                  20.000 PCT
 END  GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET      NET OPER   NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81       .052     13.500       .039     10.192     59.603    475.400      1.800   -417.597   -417.597   -422.910
12-82       .212     55.054       .160     41.566    260.134         0.      1.926    258.208   -159.389   -231.249
12-83       .148     38.480       .112     29.053    194.462         0.      2.061    192.401     33.012   -114.300
12-84       .109     28.412       .082     21.451    153.458         0.      2.205    151.253    184.265    -39.012
12-85       .084     21.838       .064     16.487    126.079         0.      2.359    123.720    307.985     11.418

12-86       .067     17.308       .050     13.068    106.824         0.      2.525    104.299    412.284     46.232
12-87       .054     14.056       .041     10.612     92.726         0.      2.701     90.025    502.309     70.839
12-88       .044     11.642       .033      8.790     82.121         0.      2.891     79.230    581.539     88.574
12-89       .038      9.800       .029      7.399     72.173         0.      3.092     69.081    650.620    101.236
12-90       .032      8.364       .024      6.315     61.634         0.      3.310     58.324    708.944    109.991

12-91       .028      7.221       .021      5.452     53.236         0.      3.540     49.696    758.640    116.099
12-92       .024      6.298       .018      4.755     46.417         0.      3.600     42.817    801.457    120.409
12-93       .022      5.541       .017      4.183     40.868         0.      3.600     37.268    838.725    123.481
12-94       .018      4.914       .014      3.710     36.191         0.      3.600     32.591    871.316    125.681
12-95       .017      4.386       .012      3.312     32.335         0.      3.600     28.735    900.051    127.269

S TOT       .949    246.814       .716    186.345   1418.261    475.400     42.810    900.051    900.051    127.269

AFTER       .205     53.186       .155     40.155    392.066         0.    147.513    244.553   1144.604    131.585

TOTAL      1.154    300.000       .871    226.500   1810.327    475.400    190.323   1144.604   1144.604    131.585


CUM.          0.         0.                  NET  OIL REVENUE       34.650          5 PCT    679.882  40 PCT    -127.100
                                             NET  GAS REVENUE     1775.677         10 PCT    419.786  50 PCT    -196.062
ULT.       1.154    300.000                  NET PROD REVENUE        0.            15 PCT    250.952  60 PCT    -246.045
                                                                                   20 PCT    131.585  80 PCT    -312.739
CUM NET INC/INV(1)     2.41                  CUM NET PW/INV(1)         .28         30 PCT    -26.768 100 PCT    -354.208
GROSS WELLS               1                  LIFE (YEARS)            55.98
MONTHS 1ST YEAR          12                  RATE OF RETURN,PCT      28.07
INITIAL W.I., PCT  100.0000                  INITIAL N.I., PCT     75.5000
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EXHIBIT 15

```
TYPICAL WELL NO. 2                                                                                        DATE: 01/16/81.
BASIN DAKOTA                                                                                              TIME: 17.20.15.
SAN JUAN CO., NEW MEXICO                                                                                  FILE: TYFW2
300 MMF PER WELL 2 X 103 PRICE                                                                            PROJ:  4
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                                  AS OF DATE:  1/ 1/1981

-END-     NET       NET        REVENUE   OPER.     NET       CAPITAL                       INCOME    CASH      CUM.
MO-YR     OIL       GAS        TO INT.   EXPENSE   INCOME    INVEST.   DEPR.     DEPL.     TAX       FLOW      NET PW
-----     MB-----   MMF-----   M$-----   M$-----   M$-----   M$-----   M$---     M$----    M$----    M$-----   M$------


12-81        .039    10.192     59.603     1.800    57.803   475.400    52.965     0.       -47.837  -369.759  -379.548
12-82        .160    41.566    260.134     1.926   258.208     0.       45.401     0.       102.147   156.061  -263.708
12-83        .112    29.053    194.462     2.061   192.401     0.       38.918     0.        73.672   118.729  -191.539
12-84        .082    21.451    153.458     2.205   151.253     0.       33.360     0.        56.588    94.665  -144.419
12-85        .064    16.487    126.079     2.359   123.720     0.       28.597     0.        45.659    78.061  -112.601

12-86        .050    13.068    106.824     2.525   104.299     0.       24.513     0.        38.297    66.002   -90.570
12-87        .041    10.612     92.726     2.701    90.025     0.       21.013     0.        33.126    56.899   -75.017
12-88        .033     8.790     82.121     2.891    79.230     0.       18.012     0.        29.385    49.845   -63.860
12-89        .029     7.399     72.173     3.092    69.081     0.       15.440     0.        25.748    43.333   -55.917
12-90        .024     6.315     61.634     3.310    58.324     0.       13.235     0.        21.643    36.681   -50.411

12-91        .021     5.452     53.236     3.540    49.696     0.       11.345     0.        18.408    31.288   -46.565
12-92        .018     4.755     46.417     3.600    42.817     0.        9.725     0.        15.884    26.933   -43.854
12-93        .017     4.183     40.868     3.600    37.268     0.        8.336     0.        13.887    23.381   -41.927
12-94        .014     3.710     36.191     3.600    32.591     0.        7.146     0.        12.214    20.377   -40.552
12-95        .012     3.312     32.335     3.600    28.735     0.        6.125     0.        10.853    17.882   -39.563

S TOT        .716   186.345   1418.261    42.810  1375.451   475.400   334.130     0.       449.674   450.377   -39.563

AFTER        .155    40.155    392.066   147.513   244.553     0.       36.770     0.        99.737   144.817   -36.937

TOTAL        .871   226.500   1810.327   190.323  1620.004   475.400   370.900     0.       549.411   595.194   -36.937

RECAP
                             GROSS       W.I.        NET                                                   DIS    PW OF NET
 INTEREST FRACTION         1.000000    1.000000    .755000         LIFE (YEARS)               55.98         PCT       M$
 OIL RESERVES,MB              1.154       1.154       .871         GROSS OIL WELLS            0.            ---    ---------
 GAS RESERVES,MMCF          300.000     300.000    226.500         GROSS GAS WELLS            1.000           5     308.592
 PRODUCTS                     0.          0.         0.            RATE OF RETURN,PCT        17.57           10     145.691
 REVENUE,M$                2613.276    2613.276   1810.327         DISCOUNT RATE,PCT         20.0            15      38.988
 OPERATING EXPENSE,M$       190.323     190.323    190.323         PAYOUT YEARS               4.00           20     -36.938
 TANGIBLES,M$               370.900     370.900    370.900                                                   30    -138.459
 INTANGIBLES,M$             104.500     104.500    104.500                                                   40    -203.508
                                                                                                             50    -248.782
 INITIAL OIL PRICE ($/B)                  44.23                    W.I. BEFORE PAYOUT,PCT 100.00             70    -307.492
 INITIAL GAS PRICE ($/M)                  6.2200                   W.I. AFTER  PAYOUT,PCT 100.00            100    -356.805
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TYPICAL WELL NO. 1A                                                                                   DATE: 01/16/81.
BASIN DAKOTA .                                                                                        TIME: 14.24.28.
SAN JUAN CO., NEW MEXICO                                                                              FILE: TYPW
400 MMF PER WELL 2 X 103 PRICE                                                                        PROJ:  2
CONSOLIDATED OIL & GAS                  R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                 AS OF DATE :  1/ 1/1981

                                                                                                              20.000 PCT
 END   GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET      NET OPER  NET INCOME CUMULATIVE CUM. DISC
MO-YR PRODUCTION PRODUCTION  INTEREST    INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81        .065     16.860       .049     12.729     74.440    475.400      1.800   -402.760   -402.760   -409.462
12-82        .271     70.407       .205     53.158    332.675      0.         1.926    330.749    -72.011   -163.955
12-83        .191     49.837       .144     37.627    251.837      0.         2.061    249.776    177.765    -12.131
12-84        .143     37.134       .108     28.036    200.583      0.         2.205    198.378    376.143     86.614
12-85        .111     28.738       .084     21.697    165.927      0.         2.359    163.568    539.711    153.286

12-86        .088     22.901       .066     17.290    141.325      0.         2.525    138.800    678.511    199.616
12-87        .072     18.677       .054     14.101    123.219      0.         2.701    120.518    799.029    232.559
12-88        .059     15.524       .045     11.721    109.513      0.         2.891    106.622    905.651    256.425
12-89        .051     13.108       .039      9.896     96.541      0.         3.092     93.449    999.100    273.554
12-90        .043     11.214       .032      8.467     82.638      0.         3.310     79.328   1078.428    285.461

12-91        .037      9.703       .028      7.326     71.513      0.         3.540     67.973   1146.401    293.816
12-92        .033      8.478       .025      6.401     62.508      0.         3.600     58.908   1205.309    299.746
12-93        .029      7.472       .022      5.641     55.087      0.         3.600     51.487   1256.796    303.990
12-94        .025      6.635       .019      5.009     48.891      0.         3.600     45.291   1302.087    307.047
12-95        .023      5.930       .017      4.478     43.718      0.         3.600     40.118   1342.205    309.264

S TOT       1.241    322.618       .937    243.577   1860.415    475.400     42.810   1342.205   1342.205    309.264

AFTER        .297     77.382       .224     58.423    570.385      0.       184.514    385.871   1728.076    315.434

TOTAL       1.538    400.000      1.161    302.000   2430.800    475.400    227.324   1728.076   1728.076    315.434


CUM.        0.          0.                   NET  OIL REVENUE        46.389          5 PCT    1057.571  40 PCT     -25.540
                                             NET  GAS REVENUE      2384.411         10 PCT     701.505  50 PCT    -115.595
ULT.        1.538    400.000                 NET PROD REVENUE         0.            15 PCT     474.477  60 PCT    -180.632
                                                                                    20 PCT     315.434  80 PCT    -267.091
CUM NET INC/INV(1)      3.63                 CUM NET PW/INV(1)         .66          30 PCT     106.120 100 PCT    -320.649
GROSS WELLS                1                 LIFE (YEARS)            66.25
MONTHS 1ST YEAR           12                 RATE OF RETURN,PCT      37.84
INITIAL W.I., PCT  100.0000                  INITIAL N.I., PCT     75.5000
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EXHIBIT 16

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TYPICAL WELL NO. 1A                                                                          DATE: 01/16/81.
BASIN DAKOTA                                                                                 TIME: 14.24.08.
SAN JUAN CO., NEW MEXICO                                                                     FILE: TYPW
400 MMF PER WELL 2 X 103 PRICE                                                               PROJ:  2
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                         AS OF DATE:  1/ 1/1991

-END-      NET       NET      REVENUE    OPER.      NET       CAPITAL                        INCOME     CASH      CUM.
MO-YR      OIL       GAS      TO INT.    EXPENSE    INCOME    INVEST.     DEPR.    DEPL.     TAX        FLOW      NET PW
-----      MB-----   MMF----- M$-----    M$-----    M$-----   M$-----     M$---    M$----    M$----     M$-----   M$------


12-81          .049    12.729    74.440     1.800    72.640   475.400    52.965    0.       -39.018  -363.741  -374.092
12-82          .205    53.158   332.675     1.926   330.749     0.       45.401    0.       131.260   199.489  -226.017
12-83          .144    37.627   251.837     2.061   249.776     0.       38.918    0.        96.995   152.781  -133.150
12-84          .108    28.036   200.583     2.205   198.378     0.       33.360    0.        75.908   122.470   -72.189
12-85          .084    21.697   165.927     2.359   163.568     0.       28.597    0.        62.087   101.481   -30.824

12-86          .066    17.290   141.325     2.525   138.800     0.       24.513    0.        52.572    86.228    -2.042
12-87          .054    14.101   123.219     2.701   120.518     0.       21.013    0.        45.773    74.745    18.388
12-88          .045    11.721   109.513     2.891   106.622     0.       18.012    0.        40.761    65.861    33.130
12-89          .039     9.896    96.541     3.092    93.449     0.       15.440    0.        35.894    57.565    43.682
12-90          .032     8.467    82.638     3.310    79.328     0.       13.235    0.        30.403    48.925    51.025

12-91          .028     7.326    71.513     3.540    67.973     0.       11.345    0.        26.049    41.924    56.179
12-92          .025     6.401    62.508     3.600    58.908     0.        9.725    0.        22.624    36.284    59.831
12-93          .022     5.641    55.087     3.600    51.487     0.        8.336    0.        19.849    31.638    62.439
12-94          .019     5.009    48.891     3.600    45.291     0.        7.146    0.        17.547    27.744    64.311
12-95          .017     4.478    43.718     3.600    40.118     0.        6.125    0.        15.637    24.481    65.664

S TOT          .937   243.577  1860.415    42.810  1817.605   475.400   334.130    0.       634.331   707.877    65.664

AFTER          .224    58.423   570.385   184.514   385.871     0.       36.770    0.       160.586   225.284    69.362

TOTAL         1.161   302.000  2430.800   227.324  2203.476   475.400   370.900    0.       794.917   933.161    69.362

RECAP
                           GROSS       W.I.        NET                                                   DIS    PW OF NET
 INTEREST FRACTION      1.000000   1.000000    .755000           LIFE (YEARS)              66.25          PCT       M$
 OIL RESERVES,MB           1.538      1.538      1.161           GROSS OIL WELLS           0.             ---   ---------
 GAS RESERVES,MMCF       400.000    400.000    302.000           GROSS GAS WELLS           1.000            5    527.983
 PRODUCTS                  0.         0.         0.              RATE OF RETURN,PCT        24.69           10    309.233
 REVENUE,M$             3508.639   3508.639   2430.800           DISCOUNT RATE,PCT          20.0           15    168.522
 OPERATING EXPENSE,M$    227.324    227.324    227.324           PAYOUT YEARS                3.09          20     69.362
 TANGIBLES,M$            370.900    370.900    370.900                                                     30    -62.046
 INTANGIBLES,M$          104.500    104.500    104.500                                                     40   -145.482
                                                                                                           50   -203.133
 INITIAL OIL PRICE ($/B)             44.24                       W.I. BEFORE PAYOUT,PCT 100.00             70   -277.220
 INITIAL GAS PRICE ($/M)             6.2200                      W.I. AFTER  PAYOUT,PCT 100.00            100   -338.575
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TYPICAL NO. 4                                                                                DATE: 01/16/81.
BASIN DAKOTA                                                                                 TIME: 17.05.01.
SAN JUAN CO., NEW MEXICO                                                                     FILE: TYPW2
500 MMF PER WELL 2 X 103 PRICE                                                               PROJ:  7
CONSOLIDATED OIL & GAS               R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                 AS OF DATE :  1/ 1/1981

                                                                                                       20.000 PCT
 END  GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO      NET     NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST  INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$----  ----M$---- ----M$---- ----M$---- ----M$----

12-81       .080     20.880       .060     15.764     92.177   475.400      1.800   -385.023   -385.023   -393.384
12-82       .338     87.890       .25(     66.357    415.275     0.         1.926    413.349     28.326    -86.566
12-83       .239     62.081       .180     46.872    313.739     0.         2.061    311.678    340.004     02.885
12-84       .178     46.184       .134     34.868    249.471     0.         2.205    247.266    587.270    225.964
12-85       .137     35.701       .104     26.955    206.105     0.         2.359    203.746    791.016    309.014

12-86       .109     28.422       .082     21.458    175.390     0.         2.525    172.865    963.881    366.714
12-87       .089     23.164       .067     17.489    152.811     0.         2.701    150.110   1113.991    407.746
12-88       .074     19.242       .056     14.528    135.769     0.         2.891    132.878   1246.869    437.488
12-89       .063     16.238       .048     12.260    119.587     0.         3.092    116.495   1363.364    458.842
12-90       .053     13.886       .040     10.483    102.321     0.         3.310     99.011   1462.375    473.704

12-91       .047     12.011       .035      9.069     88.565     0.         3.540     85.025   1547.400    484.155
12-92       .040     10.492       .030      7.921     77.327     0.         3.600     73.727   1621.127    491.576
12-93       .035      9.243       .027      6.979     68.114     0.         3.600     64.514   1685.641    496.893
12-94       .032      8.205       .024      6.194     60.497     0.         3.600     56.897   1742.538    500.734
12-95       .028      7.333       .021      5.537     54.047     0.         3.600     50.447   1792.985    503.522

S TOT      1.542    400.972      1.164    302.734   2311.195   475.400     42.810   1792.985   1792.985    503.522

AFTER       .381     99.020       .288     74.766    729.970     0.       212.360    517.610   2310.595    511.352

TOTAL      1.923    500.000      1.452    377.500   3041.165   475.400    255.170   2310.595   2310.595    511.352

CUM.       0.         0.                  NET  OIL REVENUE      58.048         5 PCT   1442.260  40 PCT     85.847
                                          NET  GAS REVENUE    2983.117        10 PCT    994.152  50 PCT    -26.512
ULT.       1.923    500.000               NET PROD REVENUE       0.           15 PCT    710.035  60 PCT   -107.669
                                                                              20 PCT    511.352  80 PCT   -215.581
CUM NET INC/INV(1)      4.86              CUM NET PW/INV(1)      1.08         30 PCT    250.110 100 PCT   -282.450
GROSS WELLS                1              LIFE (YEARS)          73.99
MONTHS 1ST YEAR           12              RATE OF RETURN,PCT    47.42
INITIAL W.I., PCT  100.0000               INITIAL N.I., PCT     75.5000
                                                                                                        EXHIBIT 17
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TYPICAL NO. 4                                                                                          DATE: 01/16/81.
BASIN DAKOTA                                                                                           TIME: 17.20.27.
SAN JUAN CO., NEW MEXICO                                                                               FILE: TYPW2
500 MMF PER WELL 2 X 103 PRICE                                                                         PROJ:  7
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                                  AS OF DATE:  1/ 1/1981

-END-     NET       NET       REVENUE   OPER.     NET       CAPITAL                        INCOME    CASH      CUM.
MO-YR     OIL       GAS       TO INT.   EXPENSE   INCOME    INVEST.   DEPR.     DEPL.      TAX       FLOW      NET PW
-----     MB-----   MMF-----  M$-----   M$-----   M$-----   M$-----   M$---     M$----     M$----    M$-----   M$------


12-81         .060    15.764    92.177     1.800    90.377   475.400    52.965    0.        -32.201  -352.821  -364.194
12-82         .256    66.357   415.275     1.926   413.349     0.       45.401    0.        176.615   236.734  -188.473
12-83         .180    46.872   313.739     2.061   311.678     0.       38.918    0.        130.925   180.753   -78.603
12-84         .134    34.868   249.471     2.205   247.266     0.       33.360    0.        102.675   144.591    -6.632
12-85         .104    26.955   206.105     2.359   203.746     0.       28.597    0.         84.072   119.674    42.148

12-86         .082    21.458   175.390     2.525   172.865     0.       24.513    0.         71.209   101.656    76.080
12-87         .067    17.489   152.811     2.701   150.110     0.       21.013    0.         61.967    88.143   100.173
12-88         .056    14.528   135.769     2.891   132.878     0.       18.012    0.         55.136    77.742   117.575
12-89         .048    12.260   119.587     3.092   116.495     0.       15.440    0.         48.506    67.989   130.037
12-90         .040    10.483   102.321     3.310    99.011     0.       13.235    0.         41.172    57.839   138.719

12-91         .035     9.069    88.565     3.540    85.025     0.       11.345    0.         35.366    49.659   144.823
12-92         .030     7.921    77.327     3.600    73.727     0.        9.725    0.         30.721    43.006   149.151
12-93         .027     6.979    68.114     3.600    64.514     0.        8.336    0.         26.965    37.549   152.246
12-94         .024     6.194    60.497     3.600    56.897     0.        7.146    0.         23.881    33.016   154.475
12-95         .021     5.537    54.047     3.600    50.447     0.        6.125    0.         21.274    29.173   156.088

S TOT        1.164   302.734  2311.195    42.810  2268.385   475.400   334.130    0.        878.283   914.703   156.088

AFTER         .288    74.766   729.970   212.360   517.610     0.       36.770    0.        230.804   286.807   160.541

TOTAL        1.452   377.500  3041.165   255.170  2785.995   475.400   370.900    0.       1109.087  1201.509   160.541

RECAP
                          GROSS       W.I.        NET                                                DIS   PW OF NET
 INTEREST FRACTION      1.000000   1.000000    .755000          LIFE (YEARS)              73.99       PCT      M$
 OIL RESERVES,MB           1.923      1.923      1.452          GROSS OIL WELLS           0.          ---   ---------
 GAS RESERVES,MMCF       500.000    500.000    377.500          GROSS GAS WELLS           1.000          5    704.975
 PRODUCTS                  0.         0.         0.             RATE OF RETURN,PCT       30.51          10    441.349
 REVENUE,M$             4389.581   4389.581   3041.165          DISCOUNT RATE,PCT         20.0          15    277.709
 OPERATING EXPENSE,M$    255.170    255.170    255.170          PAYOUT YEARS               2.64         20    160.541
 TANGIBLES,M$            370.900    370.900    370.900                                                30      5.518
 INTANGIBLES,M$          104.500    104.500    104.500                                                40    -92.776
                                                                                                      50   -160.616
 INITIAL OIL PRICE ($/B)            44.24                       W.I. BEFORE PAYOUT,PCT 100.00         70   -247.650
 INITIAL GAS PRICE ($/M)            6.2200                      W.I. AFTER  PAYOUT,PCT 100.00        100   -319.490
```

```
TYPICAL WELL NO. 5A                                                                                        DATE: 01/19/81.
BASIN DAKOTA                                                                                               TIME: 15.51.36.
SAN JUAN CO., NEW MEXICO                                                                                   FILE: TYPW3
650 MMF PER WELL 2 X 103 PRICE                                                                             PROJ:  9
CONSOLIDATED OIL & GAS                  R E S E R V E S   A N D   E C O N O M I C S
ECONOMICS OF DEVELOPMENT
                                                  AS OF DATE :  1/ 1/1981

                                                                                                                 20.000 PCT
 END   GROSS  OIL GROSS  GAS OIL TO NET GAS TO NET REVENUE TO     NET     NET OPER  NET INCOME CUMULATIVE CUM.  DISC
MO-YR PRODUCTION PRODUCTION  INTEREST   INTEREST   INTEREST   INVESTMENT  EXPENSES  BEFORE FIT NET INCOME NET INCOME
----- ----MB---- ----MMF--- ----MB---- ----MMF--- ----M$---- ----M$---- ----M$---- ----M$---- ----M$---- ----M$----

12-81       .138     36.000       .104     27.180    158.927    475.400      1.800   -318.273   -318.273   -332.880
12-82       .433    112.444       .327     84.895    531.288         0.      1.926    529.362    211.089     60.052
12-83       .305     79.256       .230     59.838    400.533         0.      2.061    398.472    609.561    302.260
12-84       .226     58.871       .171     44.448    317.977         0.      2.205    315.772    925.333    459.439
12-85       .175     45.455       .132     34.319    262.431         0.      2.359    260.072   1185.405    565.447

12-86       .139     36.155       .108     27.297    223.120         0.      2.525    220.595   1406.000    639.080
12-87       .113     29.445       .085     22.231    194.243         0.      2.701    191.542   1597.542    691.436
12-88       .094     24.445       .071     18.456    172.480         0.      2.891    169.589   1767.131    729.396
12-89       .080     20.617       .061     15.565    151.838         0.      3.092    148.746   1915.877    756.661
12-90       .067     17.625       .050     13.307    129.862         0.      3.310    126.552   2042.429    775.657

12-91       .059     15.239       .045     11.506    112.345         0.      3.540    108.805   2151.234    789.031
12-92       .051     13.307       .038     10.047     98.084         0.      3.600     94.484   2245.718    798.541
12-93       .045     11.720       .034      8.848     86.389         0.      3.600     82.789   2328.507    805.365
12-94       .040     10.402       .031      7.854     76.676         0.      3.600     73.076   2401.583    810.298
12-95       .036      9.294       .027      7.017     68.518         0.      3.600     64.918   2466.501    813.886

S TOT      2.001    520.275      1.511    392.808   2984.711    475.400     42.810   2466.501   2466.501    813.886

AFTER       .499    129.725       .376     97.942    956.245         0.    247.119    709.126   3175.627    824.033

TOTAL      2.500    650.000      1.887    490.750   3940.956    475.400    289.929   3175.627   3175.627    824.033


CUM.          0.         0.             NET  OIL REVENUE          75.290          5 PCT   2021.816  40 PCT    276.633
                                        NET  GAS REVENUE        3865.666         10 PCT   1444.111  50 PCT    131.446
ULT.       2.500    650.000             NET PROD REVENUE              0.         15 PCT   1079.159  60 PCT     26.226
                                                                                 20 PCT    824.033  80 PCT   -114.432
CUM NET INC/INV(1)       6.68           CUM NET PW/INV(1)           1.73         30 PCT    488.258 100 PCT   -202.316
GROSS WELLS                 1           LIFE (YEARS)               83.64
MONTHS 1ST YEAR            12           RATE OF RETURN,PCT         63.31
INITIAL W.I., PCT    100.0000           INITIAL N.I., PCT        75.5000
```

EXHIBIT 18

```
                                                                                        DATE: 01/19/81.
                                                                                        TIME: 15.59.03.
                                                                                        FILE: TYPW3
                                                                                        PROJ:  9
TYPICAL WELL NO. 5A
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
450 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

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

                                    AS OF DATE:  1/ 1/1981

                                                                                       INCOME   CASH      CUM.
                                         OPER.    NET       CAPITAL                          TAX      FLOW      NET PW
-END-    NET      NET      REVENUE   EXPENSE  INCOME    INVEST.   DEPR.    DEPL.    M$----   M$-----   M$------
MO-YR    OIL      GAS      TO INT.   M$-----  M$-----   M$-----   M$---    M$----
-----    MB-----  MMF----- M$-----

12-81     .104    27.180   158.927   1.800    157.127   475.400   52.965   0.        -.161   -318.111  -332.732
12-82     .327    84.895   531.288   1.926    529.362   0.        45.401   0.       232.301   297.061  -112.232
12-83     .230    59.838   400.533   2.061    398.472   0.        38.918   0.       172.586   225.886    25.071
12-84     .171    44.448   317.977   2.205    315.772   0.        33.360   0.       135.558   180.214   114.774
12-85     .132    34.319   262.431   2.359    260.072   0.        28.597   0.       111.108   148.964   175.494

12-86     .105    27.297   223.120   2.525    220.595   0.        24.513   0.        94.119   126.476   217.710
12-87     .085    22.231   194.243   2.701    191.542   0.        21.013   0.        81.854   109.688   247.692
12-88     .071    18.456   172.480   2.891    169.589   0.        18.012   0.        72.757    96.832   269.367
12-89     .061    15.565   151.838   3.092    148.746   0.        15.440   0.        63.987    84.759   284.903
12-90     .050    13.307   129.862   3.310    126.552   0.        13.235   0.        54.392    72.160   295.734

12-91     .045    11.506   112.345   3.540    108.805   0.        11.345   0.        46.781    62.024   303.358
12-92     .038    10.047    98.084   3.600     94.484   0.         9.725   0.        40.684    53.800   308.774
12-93     .034     8.848    86.389   3.600     82.789   0.         8.336   0.        35.737    47.052   312.652
12-94     .031     7.854    76.676   3.600     73.076   0.         7.146   0.        31.646    41.430   315.448
12-95     .027     7.017    68.518   3.600     64.918   0.         6.125   0.        28.220    36.698   317.477

S TOT    1.511   392.808  2984.711  42.810   2941.901   475.400  334.130   0.      1201.569  1264.931   317.477

AFTER     .376    97.942   956.245  247.119   709.126   0.        36.770   0.       322.731   386.395   323.135

TOTAL    1.887   490.750  3940.956  289.929  3651.027   475.400  370.900   0.      1524.300  1651.326   323.135

                                                                                          DIS   PW OF NET
RECAP                        GROSS     W.I.      NET                                      PCT      M$
                                                                                          ---   ---------
  INTEREST FRACTION        1.000000  1.000000   .755000    LIFE (YEARS)          83.64      5   1006.323
  OIL RESERVES,MB             2.500     2.500     1.887    GROSS OIL WELLS       0.        10    678.324
  GAS RESERVES,MMCF         650.000   650.000   490.750    GROSS GAS WELLS       1.000     15    469.652
  PRODUCTS                    0.        0.        0.       RATE OF RETURN,PCT    40.70     20    323.135
  REVENUE,M$               5688.415  5688.415  3940.956    DISCOUNT RATE,PCT     20.0      30    129.355
  OPERATING EXPENSE,M$      289.929   289.929   289.929    PAYOUT YEARS          2.09      40      6.433
  TANGIBLES,M$              370.900   370.900   370.900                                    50    -78.478
  INTANGIBLES,M$            104.500   104.500   104.500                                    70   -187.565
                                                           W.I. BEFORE PAYOUT,PCT 100.00  100   -277.821
  INITIAL OIL PRICE ($/B)              44.24               W.I. AFTER  PAYOUT,PCT 100.00
  INITIAL GAS PRICE ($/M)              6.2200
```

Consolidated Oil & Gas, Inc.

WELL COST ESTIMATE

AVERAGE DAKOTA WELL WITH UPPER & LOWER DAKOTA, 2 FRACS.

AFE No.__________
C.O.G. WI.__________

TO: Drill (X) Recomplete ( ) Work Over ( )
State New Mexico County San Juan Field Basin Dakota
Lease Name Average Dakota Well Lease No.________ Well No. Unnamed No. 1
Location: T31N, R12 & 13W - Average Dakota Well

DETAIL COST ESTIMATE

INTANGIBLE COSTS	QUANTITY	PRICE	COST OF DRY HOLE	COST OF PRODUCER
Superintendence	15/20	200	3,000	4,000
Labor			1,000	2,500
Hauling			1,500	7,500
Drilling				
To Drill	7,000	16/ft.	112,000	112,000
Day Work - W/DP	2	5,600	11,200	11,200
Day Work - W/out Drill pipe				
Other Completion unit with compl. equip	12	2,500		30,000
Fuel			750	1,500
Water			10,000	14,000
Right of Way Damages			2,500	2,500
Drlg. Mud & Chemicals (Have been having LC)			17,500	17,500
Electric & Radioactivity Logs			16,500	19,500
Coring & Core Analysis				
Acidizing & Fracturing 2 fracs using Nitrogen				90,000
Drill Stem Tests				
Gun Perforating 2 Dakota zones				6,000
Cement & Cementing Services Surf. & 3-stage prod.			3,000	17,500
Shoes, Collars, & Centralizers DV tools prod.			1,000	5,000
Welding			250	750
Road & Location			4,000	4,000
Bits & Coreheads				750
Mud Logging				
Plugging Expense			7,500	
Directional Drilling Services				
Overhead			1,500	2,000
Tool Rental				5,000
Contingencies 5%			9,700	17,700
TOTAL INTANGIBLE COSTS			202,900	370,900
PERMANENT EQUIPMENT				
Conductor Pipe " OD				
Surface Casing 8-5/8" OD, 24#	250	10.00	2,500	2,500
Prod. Casing 5½ " OD 15.5#	7000	7.20		50,400
Tubing 1½ " OD	7000	2.30		16,100
Casing Head Assembly			1,500	1,500
Tubing Head Assembly				1,250
Xmas Tree & Manifold Assembly				8,250
Production Packer				
Tubing Catcher	EXHIBIT 19			
Bottom Hole Choke				
Miscellaneous Connections				2,000
Production Unit & Tank Battery				22,500
TOTAL Permanent Equipment			4,000	104,500
TOTAL COST OF COMPLETED WELL			206,900	475,400

Date:__________ Recommended by:__________
APPROVED (Company):__________ Approved by:__________
By:__________ Date: January 9, 1981

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
LARRY KEHOE
SECRETARY

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

April 15, 1982

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

Re: Tight Formation
Designations

Dear Mr. Kilchrist:

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

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

If we can be of further assistance, please advise.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr
enc.

United States Department of the Interior

OFFICE OF THE SECRETARY
Minerals Management Service
South Central Region
P. O. Box 26124
Albuquerque, New Mexico 8[illegible]125

FEB 10 1982
OIL CON

FEB 08 1982

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

Dear Mr. Pearce:

This jurisdictional agency concurs in the recommendation of the State of New Mexico, Case No. 7361, Order No. R-6884, dated January 12, 1982, that the Dakota formation underlying the described lands in subject order in San Juan County, New Mexico, be designated as a Section 107 tight formation.

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

Sincerely yours,

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

CORRECTED COPY

FLUID SAMPLE DATA

Sampler Pressure ______ P.S.I.G. at Surface
Recovery: Cu. Ft. Gas ______
cc. Oil ______
cc. Water ______
cc. Mud ______
Tot. Liquid cc. ______
Gravity ______ ° API @ ______ °F.
Gas/Oil Ratio ______ cu. ft./bbl.

	RESISTIVITY		CHLORIDE CONTENT
Recovery Water	______ @	______ °F.	______ ppm
Recovery Mud	______ @	______ °F.	______ ppm
Recovery Mud Filtrate	______ @	______ °F.	______ ppm
Mud Pit Sample	______ @	Fresh water °F.	______ ppm
Mud Pit Sample Filtrate	______ @	______ °F.	______ ppm

Mud Weight ______ vis ______ sec.

Date 7-31-80
Ticket Number 727294
Kind of D.S.T. CASED HOLE
Halliburton Location FARMINGTON
Tester MR. BROWN
MR. ROBLES
Witness
Drilling Contractor SPARTAN DRILLING COMPANY DR BC

EQUIPMENT & HOLE DATA

Formation Tested Basin Dakota
Elevation 6940' Ft.
Net Productive Interval 51' from7284-7445' Ft.
All Depths Measured From Kelly Bushing
Total Depth 7480' Ft.
Main Hole/Casing Size 4 1/2" 10.5# Liner
Drill Collar Length - I.D. -
Drill Pipe Length 7229.9' I.D. 1.995"
Packer Depth(s) 7249' Ft.
Depth Tester Valve 7235.5' Ft.

Cushion TYPE Fresh water AMOUNT 4 bbls. 1000' Ft. Depth Back Pres. Valve
Surface Choke 1/8"
Bottom Choke 5/8"

Recovered 240 Feet of water
Recovered Feet of
Recovered Feet of
Recovered Feet of
Recovered Feet of

Mea. From Tester Valve

Remarks See production test data sheet

Q-Questionable

TEMPERATURE	Gauge No. 7489 Depth: 7245 Ft.		Gauge No. 5160 Depth: 7257.2' Ft.		Gauge No. Depth: Ft.		TIME (00:00-24:00 hrs.)	
Est. °F.	24 Hour Clock Blanked Off No		24 Hour Clock Blanked Off Yes		Hour Clock Blanked Off		Tool Opened 0056	
Actual 190 °F.	Pressures		Pressures		Pressures		Opened Bypass 1100	
————	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic	3375 0	3120.6	3192 0	3117.2				
First Period Flow Initial	130.8	346.3-0	128	352.5 0			—	—
First Period Flow Final	130.8	150.3	128	147.4			120	126
First Period Closed in	2383	2382.2	2426.8	2382.1			484	478
Second Period Flow Initial							—	—
Second Period Flow Final								
Second Period Closed in								
Third Period Flow Initial							—	—
Third Period Flow Final								
Third Period Closed in								
Final Hydrostatic	3590 0	3120.6	3320 0	3117.2			—	—

Legal Location Sec. - Twp. - Rng. 14-31N-12W
Lease Name EAST
Well No. 7-E
Test No. 1
Field Area BASIN DAKOTA
Tested Interval 7249-7480'
County SAN JUAN
State NEW MEXICO
Lease Owner/Company Name SOUTHLAND ROYALTY COMPANY

FORM 181-R2 - PRINTED IN U.S.A.

FORMATION TEST DATA

LITTLE'S 111033 75C 2/80

⑥

Casing perfs_____ Bottom choke_____ Surf. temp_____°F Ticket No. 727294
Gas gravity_____ Oil gravity_____ GOR_____
Spec. gravity_____ Chlorides_____ppm Res._____@_____°F
INDICATE TYPE AND SIZE OF GAS MEASURING DEVICE USED_____

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
2218					On location, made up tools
2218					Trip in hole with tools
0016					On bottom
0056					Hydrospring opened
0056					Moderate blow to surface
0101	Blow Hose	.25#			
0102	"	1			
0103	"	2			
0.04	"	3			
0109	"	3.5			
0118	"	4			
0123	"	4			
0128	"	4.5			
0133	"	4			
0138		4.5			
0142		4.5			Gas to surface
0147	3/4"				Opened choke, flare to pit with 1/8"
					orifice tester
0256					Closed tool
1100					Trip out of hole with tools

FORM 182-R1—PRINTED IN U.S.A.

PRODUCTION TEST DATA

LITTLE'S 96672 5M 8/74

SOUTHLAND ROYALTY COMPANY
Lease Owner/Company Name

727294
Ticket Number

B.T. 7489
Depth 7245'

B.T. 5160
Depth 7257.2'

B.T.
Depth

INITIAL FLOW

	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0.	.0000		346.3-Q	.0000		352.5-Q			
1.	.0885		613.3*	.0861		155.9			
2.	.1566		165.5	.1522		160.2			
3.	.2247		163.3	.2184		153.8			
4.	.2928		156.8	.2846		149.5			
5.	.3609		154.6	.3508		149.5			
6.	.4290		150.3	.4170		147.4			
	20 minute intervals								
	*Interval = 26 minutes								
	126 TOTAL MINUTES								
	INITIAL CLOSED IN PRESSURE								
0.	.0000	-----	150.3	.0000	----	147.4			
1.	.0342	1.132	444.4	.0332	1.132	425.2			
2.	.0684	.862	684.0	.0664	.862	668.8			
3.	.1026	.714	893.2	.0996	.715	886.7			
4.	.1368	.617	1053.8	.1328	.617	1048.8			
5.	.1710	.545	1191.8	.1660	.546	1193.2			
6.	.2052	.490	1323.2	.1992	.490	1326.9			
7.	.2394	.446	1439.6	.2324	.446	1443.7			
8.	.2736	.410	1547.4	.2656	.410	1552.0			
9.	.3078	.379	1644.4	.2988	.379	1647.5			
10.	.3421	.353	1730.6	.3320	.353	1726.1			
11.	.4447	.293	1896.5	.4316	.294	1891.7			
12.	.5473	.251	2000.0	.5312	.252	1997.8			
13.	.6499	.220	2079.9	.6308	.220	2076.4			
14.	.7526	.196	2140.3	.7304	.196	2135.8			
15.	.8552	.177	2187.8	.8300	.177	2184.6			
16.	.9578	.161	2231.0	.9296	.161	2227.1			
17.	1.0605	.148	2265.6	1.0292	.148	2263.2			
18.	1.1631	.136	2293.7	1.1288	.137	2284.4			
19.	1.2657	.127	2319.6	1.2284	.127	2318.4			
20.	1.3684	.118	2343.4	1.3280	.119	2339.6			
21.	1.4710	.111	2360.6	1.4276	.111	2346.0			
22.	1.5736	.105	2375.8	1.5272	.105	2373.6			
23.	1.6350	.101	2382.2	1.5870	.101	2382.1			
	First 10 intervals = 10 minutes each; next 12 intervals = 30 minutes								
	each; last interval = 18 minutes								
	478 TOTAL MINUTES								

Remarks:
Q = Questionable

Gas Production

CORRECTED COPY

B.T. Gauge Numbers			7489	5160	Ticket Number		727294	
			PRESSURE	PRESSURE				
Initial Hydrostatic			3121	3117	Elevation		6940	ft.
Final Hydrostatic			3121	3117	Production Rate	1st Flow	21.6	MCF
1st Flow	Initial	Time	346	353		2nd Flow	-	MCF
	Final	126	150	147		3rd Flow	-	MCF
	Closed In Pressure	478	2382	2382	Hole Size		6.25	in.
2nd Flow	Initial	Time			Footage Tested		51	ft.
	Final				Mud Weight		8.33	lbs./gal.
	Closed In Pressure				Gas Viscosity		.020	cp
3rd Flow	Initial	Time			Gas Gravity		.70	—
	Final				Gas Compressibility		.85	—
	Closed In Pressure				Temperature		190	°F
Extrapolated Static Pressure		1st	2644	2639				
		2nd						
		3rd						
Slope P/10		1st	89	74				
		2nd						
		3rd						

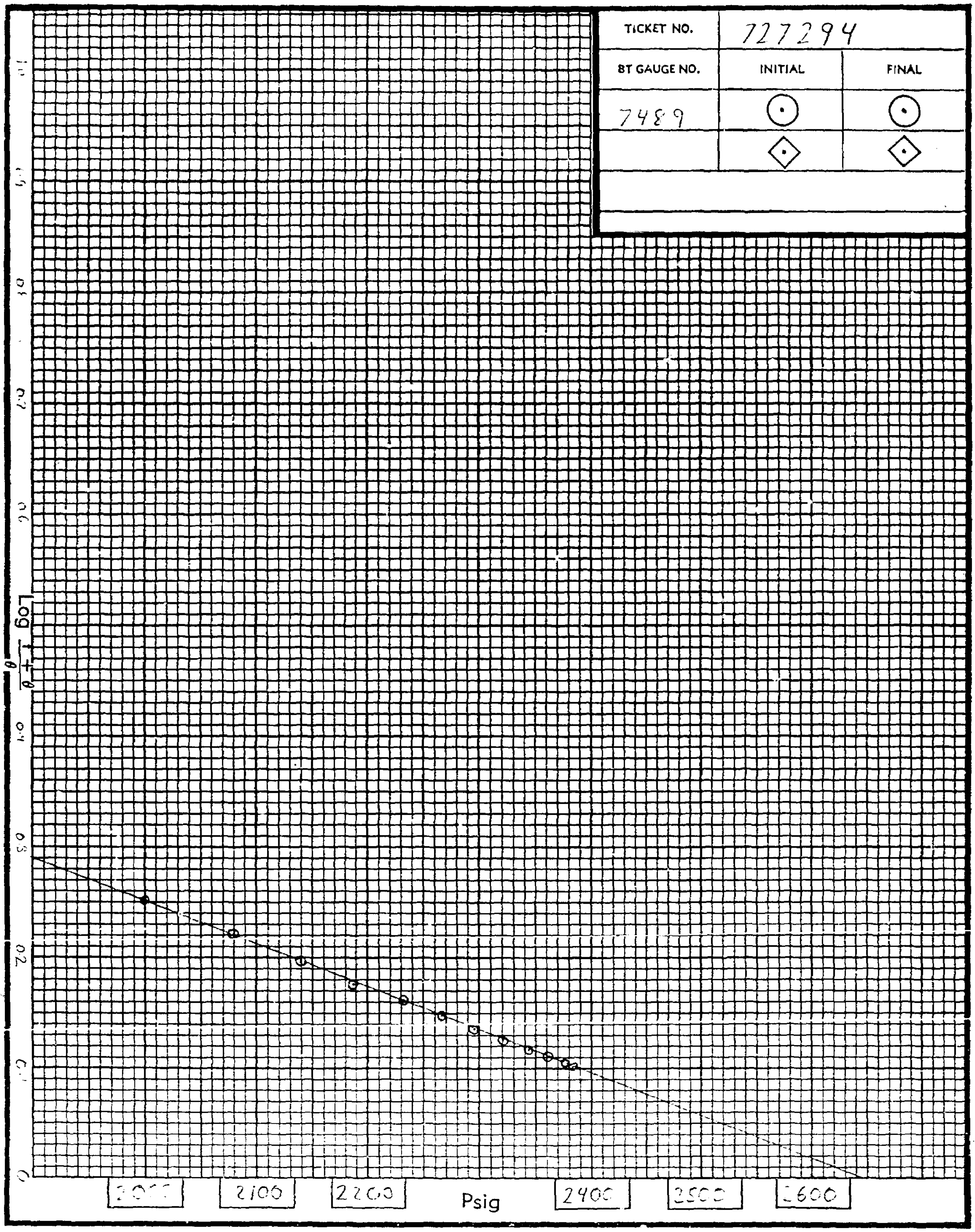
Remarks: (1) Calculations based on rates given by Bob Fielden 8-11-80 and net pay given by Marlin Thompson 10-6-80

(2) Gas gravity changed to 0.70-11-13-80

SUMMARY		B.T. Gauge No. 7489 Depth 7245'			B.T. Gauge No. 5160 Depth 7257'			
PRODUCT	EQUATION	FIRST	SECOND	THIRD	FIRST	SECOND	THIRD	UNITS
Transmissibility	$\frac{Kh}{\mu} = \frac{1637 Q_g ZT}{m}$	2.798			2.807			$\frac{\text{md. ft.}}{\text{cp}}$
Theoretical Flow Capacity	$Kh = \frac{Kh}{\mu} \mu$	.0560			.0561			md. ft.
Average Effective	$K = \frac{Kh}{h}$	.00110			.00110			md.
Permeability	$K_1 = \frac{Kh}{h_1}$	-			-			md.
Indicated Flow Capacity	$(Kh)_b = \frac{3200 Q_g \mu ZT \text{Log}(0.472 b/r_w)}{P_s^2 - P_f^2}$	.0066			.0067			md. ft.
Damage Ratio	$DR = \frac{\text{Theo. Flow Cap}}{\text{Indicated Flow Cap}} \quad \frac{Kh}{(Kh)_b}$	8.454			8.390			—
Indicated	$OF_1 = \frac{Q_g \quad P_s^2}{P_s^2 - P_f^2}$ Max.	21.670			21.667			MCFD
Flow Rate	$OF_2 = \frac{Q_g \quad P_s}{\sqrt{P_s^2 - P_f^2}}$ Min.	21.635			21.634			MCFD
Theoretical	$OF_3 = OF_1 \ DR$ Max.	183.205			181.791			MCFD
Potential Rate	$OF_4 = OF_2 \ DR$ Min.	182.910			181.509			MCFD
Approx. Radius of Investigation	$b \rightleftharpoons \sqrt{Kt}$ or $\sqrt{Kt_0}$	.632			.633			ft.
	$b_1 \rightleftharpoons \sqrt{K_1 t}$ or $\sqrt{K_1 t_0}$	-			-			ft.
Potentiometric Surface ✲	Pot. $= (El - GD) + (2.319 P_s)$	-			-			ft.

NOTICE: These calculations are based upon information furnished by you and taken from Drill Stem Test pressure charts, and are furnished you for your information. In furnishing such calculations and evaluations based thereon, Halliburton is merely expressing its opinion. You agree that Halliburton makes no warranty express or implied as to the accuracy of such calculations or opinions, and that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise, in connection with such calculations and opinions.

FORM 185 R1—PRINTED IN U.S.A. INTERPRETATIONS AND CALCULATIONS LITTLE'S

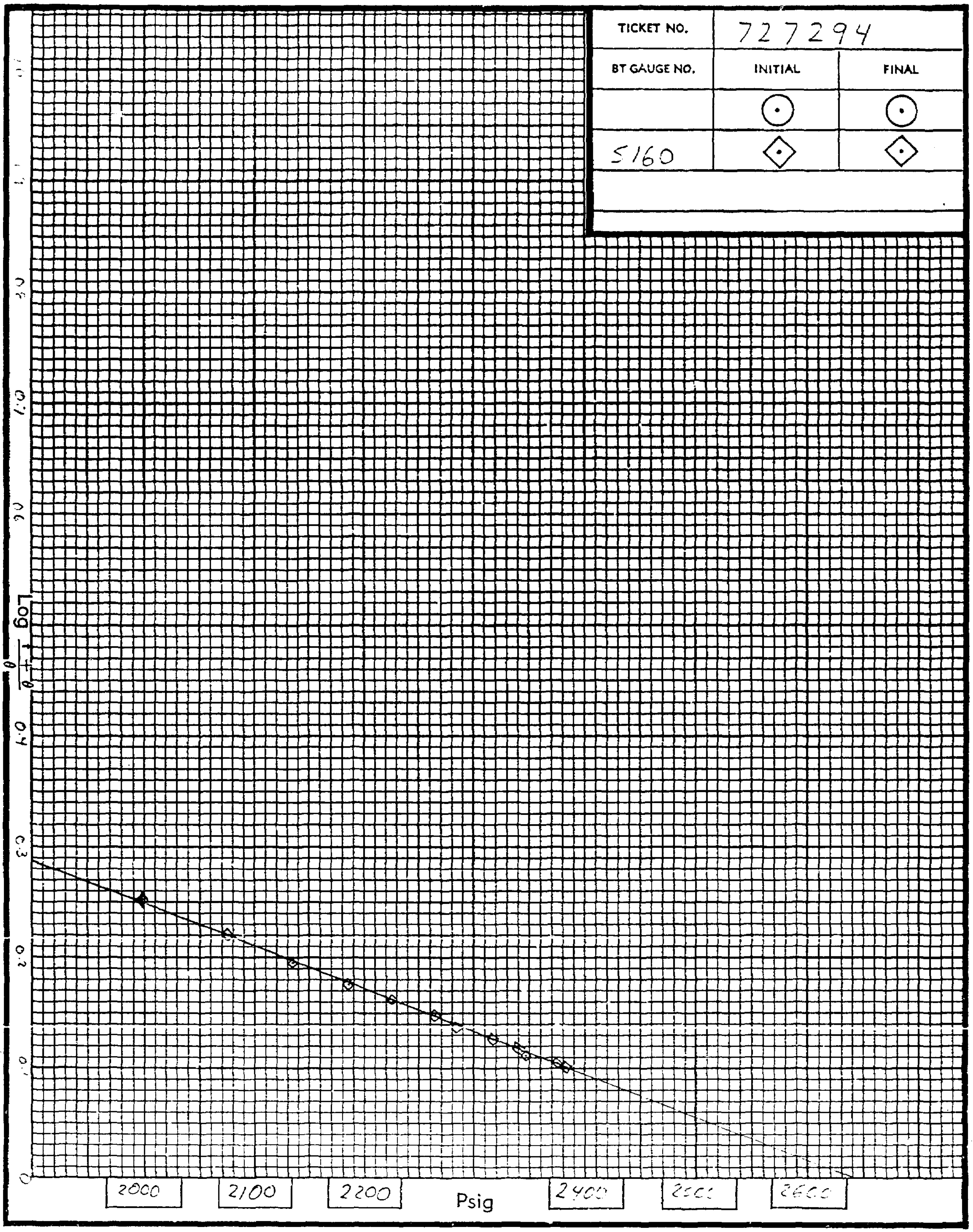


TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
7489	⊙	⊙
	◈	◈

EXTRAPOLATED PRESSURE GRAPH

FORM 184—PRINTED IN U.S.A.

LITTLE S



TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
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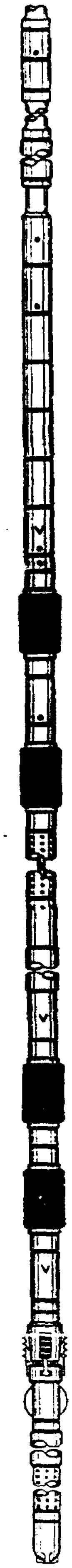
5160	◇	◇

EXTRAPOLATED PRESSURE GRAPH

FORM 184—PRINTED IN U.S.A.

LITTLE 5

TICKET NO. 727294



	O. D.	I. D.	LENGTH	DEPTH
Drill Pipe or Tubing	2 3/8"	1.995"	7229.9'	
Drill Collars				
Reversing Sub				
Water Cushion Valve				
Drill Pipe				
Drill Collars				
Handling Sub & Choke Assembly				
Dual CIP Valve	3.03"	1"	5'6"	7229.9'
Dual CIP Sampler				
Hydro-Spring Tester	3.03"	1.13"	4'10"	7235.5'
Multiple CIP Sampler				
Extension Joint				
AP Running Case	3.03"	2.31"	4'8½"	7245'
X over				
Hydraulic Jar				
VR Safety Joint	3.03"	1.75"	2'8½"	
Pressure Equalizing Crossover X over	3.03"	1.75"	1'	
Packer Assembly	4½"	1.90"	3'4"	7249'
Distributor				
Packer Assembly				
Perforated anchor	2 3/8"	1.90"	4'2"	
Flush Joint Anchor				
Pressure Equalizing Tube				
Blanked-Off B.T. Running Case				
Drill Collars				
Anchor Pipe Safety Joint				
Packer Assembly				
Distributor				
Packer Assembly				
Anchor Pipe Safety Joint				
Side Wall Anchor				
Drill Collars				
Flush Joint Anchor				
Blanked-Off B.T. Running Case	3.03"	2.31"	4'	7257.2'
Total Depth				7480'

FORM 187-R2 — PRINTED IN U.S.A.

EQUIPMENT DATA

LITTLE'S 111036 75C 2/80

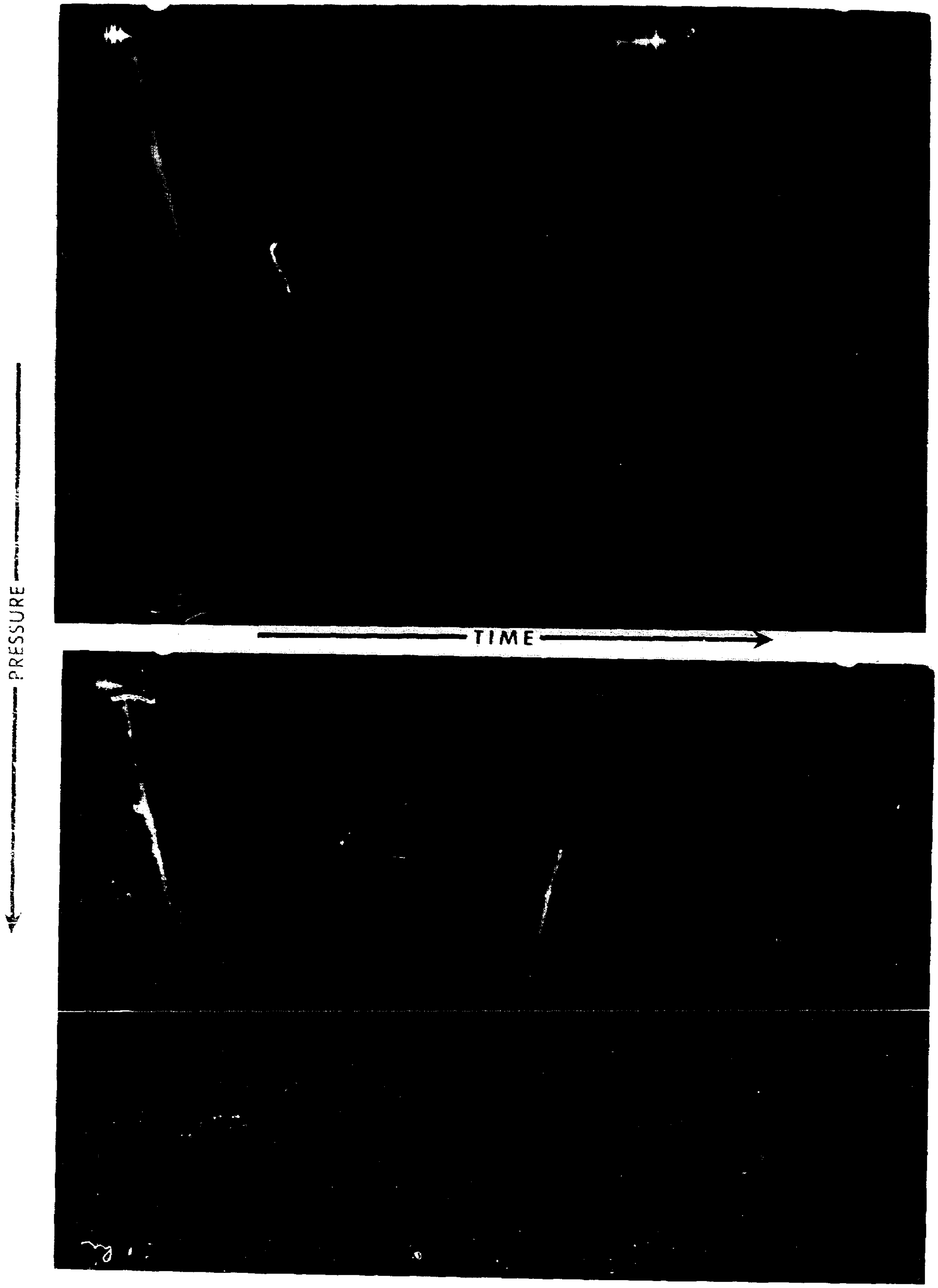
Formation Testing Service Report

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 5
CASE NO.

8 [illegible] 52

5

HALLIB



Each Horizontal Line Equal to 1000 p.s.i.

b	Approximate R
b	App[illegible] R
D.R.	Damage Ratio
El	Elevation
GD	B.T. Gauge Dep
h	Interval Tested
h	Net Pay Thickn
K	Permeability
K	Permeability, F
m	Slope Extrapolat
OF	Maximum Indic
OF	Maximum Indica
OF	Theoretical Op
OF	Theoretical Op
P	Extrapolated Sta
P	Final Flow Press
P	Potentiometric S
Q	Average Adjuste
Q	Theoretical Prod
Q	Measured Gas F
R	Corrected Recov
r	Radius of Well B
t	Flow Time
t	Total Flow Time
T	Temperature Ran
[illegible]	[illegible]
[illegible]	[illegible]
log	[illegible]

NOMENCLATURE

b = Approximate Radius of Investigation .... Feet

b_1 = Approximate Radius of Investigation (Net Pay Zone h_1) .... Feet

D.R. = Damage Ratio .... ——

El = Elevation .... Feet

GD = B.T. Gauge Depth (From Surface Reference) .... Feet

h = Interval Tested .... Feet

h_1 = Net Pay Thickness .... Feet

K = Permeability .... md

K_1 = Permeability (From Net Pay Zone h_1) .... md

m = Slope Extrapolated Pressure Plot (Psi^2/cycle Gas) .... psi/cycle

OF_1 = Maximum Indicated Flow Rate .... MCF/D

OF_2 = Minimum Indicated Flow Rate .... MCF/D

OF_3 = Theoretical Open Flow Potential with/Damage Removed Max. .... MCF/D

OF_4 = Theoretical Open Flow Potential with/Damage Removed Min. .... MCF/D

P_s = Extrapolated Static Pressure .... Psig.

P_F = Final Flow Pressure .... Psig.

P_{ot} = Potentiometric Surface (Fresh Water *) .... Feet

Q = Average Adjusted Production Rate During Test .... bbls/day

Q_1 = Theoretical Production w/Damage Removed .... bbls/day

Q_g = Measured Gas Production Rate .... MCF/D

R = Corrected Recovery .... bbls

r_w = Radius of Well Bore .... Feet

t = Flow Time .... Minutes

t_o = Total Flow Time .... Minutes

T = Temperature Rankine .... °R

Z = Compressibility Factor .... ——

μ = Viscosity Gas or Liquid .... CP

Log = Common Log

* Potentiometric Surface Reference to Rotary Table When Elevation Not Given, Fresh Water Corrected to 100 F.

NUMBER, NAME AND PURPOSE OF EACH EXHIBIT
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Exhibit Number	Exhibit Name	Purpose of Exhibit
1	Completion and Production Map	Show location of Dakota completions, production from Dakota completions, proposed tight gas area, location of cross sections, test wells and dry holes
2	Type Log	Show log characteristics and depth of Dakota formation
3	Cross Section A-A'	Show Dakota formation development in a north-south direction
4	Cross Section B-B'	Show Dakota formation development in an east-west direction
5	Formation Testing Service Report	Show in situ permeability from pressure buildup analysis
6	Darcy Law Calculation	Show in situ permeability from Darcy Law calculation
7	Darcy Law Calculation	Show in situ permeability from Darcy Law calculation
8	Technical Paper	Show relaitonship of in situ permeability to laboratory permeability
9	Explanation of Paper	Explain method of determining in situ permeability from routine core analysis
10	Core Analysis	Show in situ permeability from core analysis
11	Core Analysis	Show in situ permeability from core analysis

Exhibit Number	Exhibit Name	Purpose of Exhibit
12	Permeability, Gas and Crude Production Data	Show in situ permeability, stabilized production rate and crude production from each test well
13	Cumulative Production and Ultimate Reserves	Show cumulative production and ultimate reserves for each well in the proposed tight formation area
14	Economic Calculation	Show economics of drilling and completing a Dakota well at the 103 gas price
15	Economic Calculation	Show economics of drilling and completing a Dakota well at 200% of the 103 price
16	Economic Assumptions	Show assumptions used in making economic calculations
17	Authority for Expenditure	Show cost to drill and complete a Dakota well

SOUTHLAND ROYALTY COMPANY
PATTERSON "B" COM. 1E
SW-2-31N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 224,000 SCFD (open hole test)
h = 34 feet (log)
Pwf= 54 psia (measured at surface and calculated to bottomhole)
Pe = 2650 psia (DST in East No. 7E located 9600' to south)
gg = .70
T = 190°F = 650°R (calc.)
re = 1320 feet
rw = 0.20 feet
Psc= 668 psia
Tsc= 392°R
Ug = .014 cps (calc.)
Z = .87 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
gg = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing

rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703\ Kh\ \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln\ (.61\ re/rw)}{(703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 224{,}000\ (.014)\frac{(650)(.87)\ \ln\ (.61\ 1320/.20)}{703\ (34)\ (2650^2 - 54^2)}$$

K = .0000877 D.

K - .0877 md.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 6
CASE NO.

6

SOUTHLAND ROYALTY COMPANY
PIERCE NO. 2
SW-30-31N-10W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Q_g = 208,000 SCFD (potential test)
h = 55 feet (log)
P_{wf} = 24 psia (calc.)
P_e = 2520 psia (calc.)
g_g = .70
T = 186°F = 646°R (calc.)
r_e = 1320 feet
r_w = .13 feet
P_{sc} = 668 psia
T_{sc} = 392
U_g = .014 cps (calc.)
Z = .91 (calc.)

Where:

Q_g = gas flow rate
h = net pay
P_{wf} = flowing bottomhole pressure
P_e = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
r_e = drainage radius for 160 acre spacing
r_w = wellbore radius
P_{sc} = pseudo critical pressure
T_{sc} = pseudo critical temperature
U_g = gas viscosity
Z = compressibility factor for gas

$$Qg = 703Kh \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln\ (.61\ re/rw)}{703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 208{,}000 \frac{(.014)(646)(.91)\ \ln\ (.61\ 1320/.13)}{703\ (55)\ (2520^2 - 24^2)}$$

$$K = .0000609\ D.$$

$$K = .0609\ md.$$

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 7
CASE NO. ____________

7

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 8
CASE NO.

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

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

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-5] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[5] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

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

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

8

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-

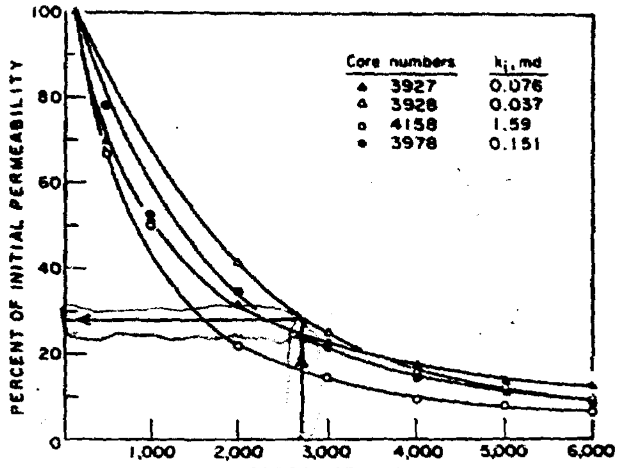


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

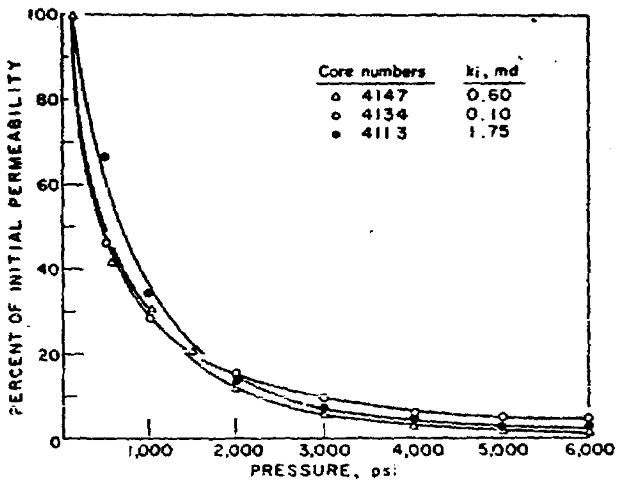


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

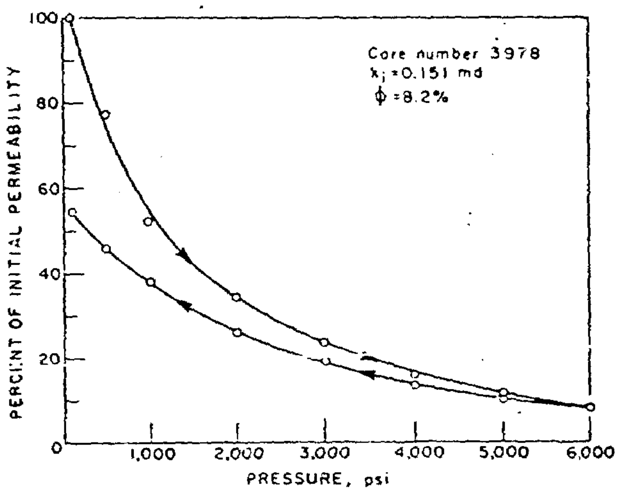


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.50	0.247	0.181	0.071	0.034	0.0186	0.0118	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.016
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.

**Slightly fractured.

†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.004
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.106	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test, it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

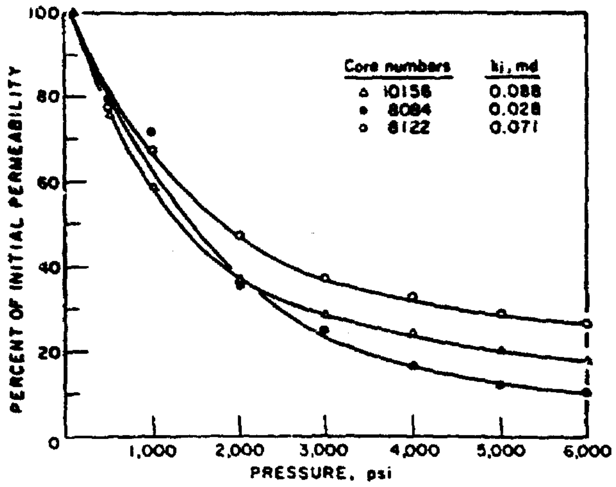


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

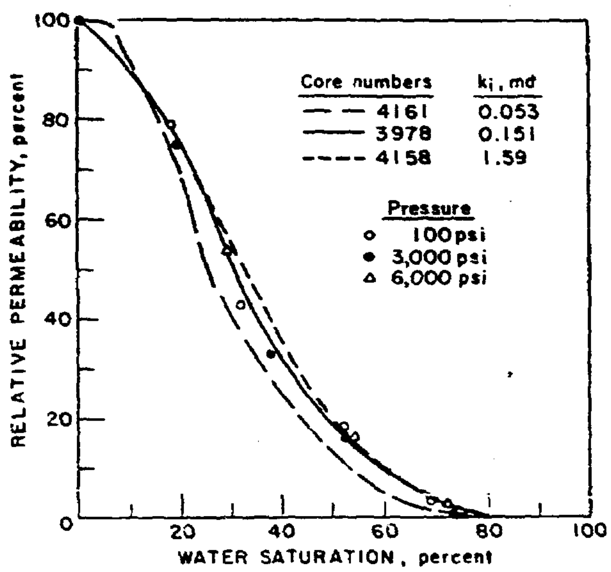


Fig. 5—Relative gas permeability of Gasbuggy cores.

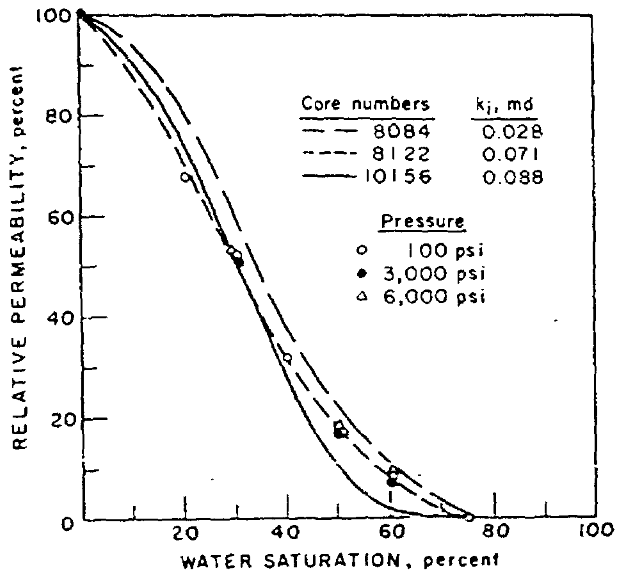


Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

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.

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.

References

1. Fatt, I. and Davis, T. H.: "The Reduction in Permeability with Overburden Pressure," *Trans.*, AIME (1952) **195**, 329.
2. McLatchie, L. S., Hemstock, R. A. and Young, J. W.: "Effective Compressibility of Reservoir Rocks and Its Effects on Permeability," *Trans.*, AIME (1958) **213**, 386-388.
3. Vairogs, Juris, Hearn, C. L., Dareing, D. W. and Rhoades, V. W.: "Effect of Rock Stress on Gas Production from Low-Permeability Reservoirs," *J. Pet. Tech.* (Sept., 1971) 1161-1167.
4. Wilson, J. W.: "Determination of Relative Permeability Under Simulated Reservoir Conditions," *AIChE Jour.* (1956) **2**, 94.
5. Fatt, I.: "The Effect of Overburden Pressure on Relative Permeability," *Trans.*, AIME (1953) **198**, 325-326.
6. *API Recommended Practice for Core-Analysis Procedure,* API RP 40, Dallas (1960) 35.

JPT

EXPLANATION OF METHOD USED
TO DETERMINE IN SITU PERMEABILITY
FROM ROUTINE CORE ANALYSIS
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Exhibit No. 8 is a paper entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", by Rex D. Thomas and Don C. Ward. This paper presents a method of determining the relationship between routine laboratory and in situ permeability. In this method initial (laboratory) permeability was determined at 100 psi (or less) external pressure. In situ conditions were then simulated by measuring the permeability at various pressures ranging from 500 to 6000 psi. Percent of initial permeability (ratio of permeability at 100 psi to permeability at higher pressures) was then plotted versus pressure. The results of the work is shown in Figure 1, page 121, of the above paper. Using Core No. 3928, which has permeability very near the average of the five test wells in this application, and a bottomhole pressure of 2650 psi, the factor necessary to correct laboratory permeability to in situ permeability is determined to 0.28.

The authors used cores from the Pictured Cliffs formation in a well in Rio Arriba County, New Mexico. This well is located approximately 50 miles southeast of the proposed tight gas area. Cores from the Dakota formation could be expected to provide results very similar to those obtained from the Pictured Cliffs formation.

The water present in the reservoir also causes the in situ permeability to be less than laboratory permeability as is discussed in Exhibit No. 8. No correction, however, has been made for water saturation.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 9
CASE NO.

EL PASO NATURAL GAS COMPANY
CASE NO. 8
NE-18-31N-11W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

	Depth (feet)	Permeability (md.)
	7254-55	.41
	55-56	.32
	56-57	.11
	57-58	.02
	58-59	.03
	59-60	.12
	60-61	.02
	61-62	.07
	7338-39	.09
	39-40	.12
	40-41	.04
	41-42	.04
	42-43	.04
	43-44	.04
	44-45	.02
	45-46	.06
	46-47	.07
	47-48	.29
	48-49	.03
	49-50	.14
	50-51	.07
	51-52	.04
	53-54	.56
	54-55	.01
	55-56	.24
	7364-65	.07
	65-66	.05
	66-67	.08
	67-68	.02
	68-69	.52
	69-70	.03
	70-71	.23
	71-72	.02
	7390-91	.33
	91-92	.03
	92-93	.02
	93-94	.02
Totals	37	4.42
Average Laboratory		.1195
Average In Situ		.0335

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 10
CASE NO.

10

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Petroleum Reservoir Engineering
DALLAS, TEXAS

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Page No. 1

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation GRANEROS
File RP-3-1441
Well CASE # 8
Core Type DIAMOND CONV.
Date Report 5/26/61
Field BASIN DAKOTA
Drilling Fluid WATER BASE MUD
Analysts McCOMAS
County SAN JUAN
State NEW MEX.
Elev 6245 GR
Location SEC 18 T31N R11W

Lithological Abbreviations

- SAND-SD
- SHALE-SH
- LIME-LM
- DOLOMITE-DOL
- CHERT-CH
- GYPSUM-GYP
- ANHYDRITE-ANHY
- CONGLOMERATE-CONG
- FOSSILIFEROUS-FOSS
- SANDY-SDY
- SHALY-SHY
- LIMY-LMY
- FINE-FN
- MEDIUM-MED
- COARSE-CSE
- CRYSTALLINE-XLN
- GRAIN-GRN
- GRANULAR-GRNL
- BROWN-BRN
- GRAY-GY
- VUGGY-VGY
- FRACTURED-FRAC
- LAMINATION-LAM
- STYLOLITIC-STY
- SLIGHTLY-SL/
- VERY-V/
- WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	7251-52	0.04	3.8	18.4	57.6	VERTICAL FRACTURE
2	52-53	0.65	3.9	17.9	38.3	" "
3	53-54	0.07	3.9	17.9	46.0	" "

7251-7254 This interval is essentially non-productive.

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DALLAS, TEXAS

Page No. 2

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation GRANEROS File RP-3-1441
Well CASE # 8 Core Type DIAMOND CONV. Date 5/27/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
4	7254-55	0.41	3.4	20.3	53.0	VERTICAL FRACTURE
5	55-56	0.32	4.4	15.9	50.0	" "
6	56-57	0.11	3.2	15.6	63.6	" "
7	57-58	0.02	3.9	17.9	64.1	" "
8	58-59	0.03	3.8	13.1	65.8	" "
9	59-60	0.12	3.6	5.6	75.0	" "
10	60-61	0.02	3.7	5.4	78.4	" "
11	61-62	0.07	3.9	0.0	74.5	" "
12	62-63	0.04	4.2	4.8	83.4	" "
13	63-64	0.04	4.8	10.4	79.3	" "
14	64-65	0.01	3.5	5.7	83.0	" "
15	65-66	0.03	3.7	0.0	89.1	" "
16	66-67	<0.01	3.8	13.1	65.9	" "
17	67-68	0.04	4.4	11.4	79.6	" "
18	68-69	0.01	4.0	17.5	60.1	" "
19	69-70	0.07	3.4	14.7	70.6	" "
20	70-71	<0.01	3.8	18.4	63.2	" "
21	71-72	0.05	5.5	12.7	41.9	" "
22	72-73	0.01	4.8	14.5	50.0	" "
23	73-74	0.10	4.9	10.2	67.4	" "
24	74-75	0.01	5.1	13.7	56.9	" "
25	75-76	0.05	5.3	13.2	66.1	" "

7254-7276 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File 3-1441
Well CASE # 8 Core Type DIAMOND CONV. 5/29/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHT-
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
26	7335-36	0.05	2.8	0.0	85.9	VERTICAL FRACTURE
27	36-37	0.04	2.3	0.0	74.1	" "
28	37-38	0.05	2.7	0.0	74.1	" "
29	38-39	0.09	3.3	6.1	60.6	" "
30	39-40	0.12	3.7	5.4	78.1	" "
31	40-41	0.04	2.8	0.0	71.6	" "
32	41-42	0.04	1.9	0.0	89.5	" "
33	42-43	0.04	4.0	17.5	59.8	" "
34	43-44	0.04	2.8	0.0	71.6	" "
35	44-45	0.02	2.5	0.0	64.1	" "
36	45-46	0.06	4.2	0.0	59.4	" "
37	46-47	0.07	4.8	0.0	45.7	" "
38	47-48	0.29	5.0	4.0	40.0	" "
39	48-49	0.03	4.7	0.0	25.4	" "
40	49-50	0.14	7.8✓	0.0	20.4	" "
41	50-51	0.07	7.4✓	0.0	24.3	" "
42	51-52	0.04	2.2	0.0	77.4	" "

7335-7345 This interval is essentially non-productive.

7345-7351 This interval is capable of producing gas, the average characteristics are; Porosity (5.7% average) Total Water saturation (35.8% average), Residual Oil Saturation (0.7% average) and Permeability (0.11 md./ft. average). The fractures in this interval are open and will enhance the permeability quite a bit.

7351-7352 This one foot interval is essentially non-productive.

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DALLAS TEXAS

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA
Well CASE # 8 Core Type DIAMOND CONV. 5/[illegible]/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMBS
County SAN JUAN State NEW MEXICO Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
43	7353-54	0.56	1.4	0.0	42.9	VERTICAL FRACTURE
44	54-55	0.01	1.1	0.0	36.3	" "
45	55-56	0.24	2.0	0.0	65.0	" "
46	7363-64	0.02	4.5	0.0	40.0	" "
47	64-65	0.07	6.9✓	0.0	29.0	" "

7353-7356 This interval is essentially non-productive from the matrix rock. It is possible that the fractures could contribute gas.

7363-7365 This two foot interval is capable of producing a low capacity gas, with most of the gas coming from the fractures.

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DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation DAKOTA
File RP-3-1441
Well CASE # 8
Core Type DIAMOND CONV.
Date Report 5/31/61
Field BASIN DAKOTA
Drilling Fluid WATER BASE MUD
Analysts McCOMAS
County SAN JUAN
State NEW MEX.
Elev. 6245 GR
Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
48	7365-66	0.05	2.7	0.0	74.0	VERTICAL FRACTURE
49	66-67	0.08	3.9	0.0	51.2	" "
50	67-68	0.02	2.2	0.0	95.5	" "
51	68-69	0.52	2.2	0.0	63.6	" "
52	69-70	0.03	2.7	0.0	74.0	" "
53	70-71	0.23	2.6	0.0	96.0	" "
54	71-72	0.02	2.6	0.0	96.0	" "

7365-7372 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation DAKOTA
Well CASE # 8
Field BASIN DAKOTA
Core Type DIAMOND CONV.
RP-3-1441
County SAN JUAN
State NEW MEX.
Elev 624' GR
Drilling Fluid WATER BASE MUD
Location SEC 18 T31N R11W
Date Report 5/31/61
Analysts McCOMAS

Lithological Abbreviations

SAND-SD, SHALE-SH, LIME-LM
DOLOMITE-DOL, CHERT-CH, GYPSUM-GYP
ANHYDRITE-ANHY, CONGLOMERATE-CONG, FOSSILIFEROUS-FOSS
SANDY-SDY, SHALY-SHY, LIMY-LMY
FINE-FN, MEDIUM-MED, COARSE-CSE
CRYSTALLINE-XLN, GRAIN-GRN, GRANULAR-GRNL
BROWN-BRN, GRAY-GY, VUGGY-VGY
FRACTURED-FRAC, LAMINATION-LAM, STYLOLITIC-STY
SLIGHTLY-SL, VERY-V, WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
				OIL	TOTAL WATER	
55	7375-76	0.17	3.0	0.0	50.0	VERTICAL FRACTURE
56	76-77	0.07	2.0	0.0	65.0	" "
57	7383-84	0.07	6.2	0.0	33.9	" "
58	84-85	0.34	9.4	0.0	28.8	" "
59	85-86	0.07	6.7	0.0	35.8	" "
60	86-87	0.12	3.5	0.0	34.4	" "
61	87-88	0.02	3.6	0.0	69.5	" "
62	7390-91	0.33	2.4	0.0	87.4	" "
63	91-92	0.03	1.8	0.0	72.2	" "
64	92-93	0.02	3.5	0.0	54.4	" "
65	93-94	0.02	3.5	0.0	57.1	" "
66	94-95	0.15	3.7	0.0	45.9	" "
67	95-96	0.02	2.1	0.0	71.3	" "
68	96-97	0.04	2.5	0.0	67.9	" "
69	97-97.5	0.02	1.4	0.0	64.1	" "

7375-7377 This interval is essentially non-productive.

7383-7388 This interval is capable of producing gas, primarily from the fractures. The average characteristics are: Porosity (5.8% average) Total Water saturation (40.4% average) Residual Oil saturation (0.0% average) and Permeability (0.12 md./ft average)

7390-7397.5 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company **EL PASO NATURAL GAS COMPANY** Formation **DAKOTA** File **RP-3-1441**
Well **CASE # 8** Core Type **DIAMOND CONV** Report **6/1/61**
Field **BASIN DAKOTA** Drilling Fluid **WATER BASE MUD** Analysts **McCOMAS**
County **SAN JUAN** State **NEW MEX.** Elev. **6245 GR** Location **SEC 18 T31N R11W**

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
				OIL	TOTAL WATER	
70	7422-23	<0.01	1.8	0.0	94.6	VERTICAL FRACTURE
71	23-24	<0.01	0.6	0.0	66.6	" "
72	24-25	<0.01	2.3	0.0	95.6	" "
73	25-26	<0.01	1.6	0.0	81.2	" "
74	26-27	0.01	1.9	0.0	89.5	" "

7422-7427 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation DAKOTA
3-1441
Well CASE #8
Core Type DIAMOND CONV.
Date Report 6/2/61
Field BASIN DAKOTA
Drilling Fluid WATER BASE MUD
Analysts McComas
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W.

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
75	7445-46	0.02	1.0	0.0	90.0	VERTICAL FRACTURE
76	46-47	0.02	2.6	0.0	96.2	
77	7454-55	0.03	2.6	19.2	65.5	VERTICAL FRACTURE

7445-7447 This interval is essentially non-productive.

7454-7455 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation DAKOTA
File RP-3-1441
Well CASE # 8
Core Type DIAMOND CONV.
Date Report 5/2/61
Field BASIN DAKOTA
Drilling Fluid WATER BASE MUD
Analysts McCOMAS
County SAN JUAN
State NEW MEX.
Elev. 6245 GR
Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD
SHALE-SH
LIME-LM
DOLOMITE-DOL
CHERT-CH
GYPSUM-GYP
ANHYDRITE-ANHY
CONGLOMERATE-CONG
FOSSILIFEROUS-FOSS
SANDY-SDY
SHALY-SHY
LIMY-LMY
FINE-FN
MEDIUM-MED
COARSE-CSE
CRYSTALLINE-XLN
GRAIN-GRN
GRANULAR-GRNL
BROWN-BRN
GRAY-GY
VUGGY-VGY
FRACTURED-FRAC
LAMINATION-LAM
STYLOLITIC-STY
SLIGHTLY-SL
VERY-V/
WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
				OIL	TOTAL WATER	
78	7462-63	0.03	6.0	0.0	71.8	VERTICAL FRACTURE
79	63-64	0.03	3.5	0.0	74.0	" "
80	64-65	0.02	2.4	0.0	91.6	" "
81	65-66	0.80	5.4	0.0	68.5	" "
82	66-67	0.69	4.0	0.0	10.0	" "

7462-7467 This interval is essentially non-productive. It is possible that continuation of this interval will be low-capacity water productive.

CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

RECEIVED
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RESERVOIR
ENGINEERING

Page No. 10

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY
Formation DAKOTA
File AP-3-1441
Well CASE # 8
Core Type DIAMOND CONV.
Date 6/4/61
Field BASIN DAKOTA
Drilling Fluid WATER BASE MUD
Analysts McCOMAS
County SAN JUAN State NEW MEXICO Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
				OIL	TOTAL WATER	
83	7473-74	0.03	2.7	0.0	92.7	
84	74-75	0.07	4.6	0.0	34.6	
85	75-76	0.30	5.6	0.0	28.5	VERTICAL FRACTURE
86	76-77	0.13	2.5	0.0	72.0	" "
87	77-78	0.10	4.6	0.0	26.0	
88	78-79	0.28	5.0	0.0	39.8	
89	79-80	0.22	6.0 ✓	0.0	26.6	
90	80-81	0.39	5.4	0.0	25.8	VERTICAL FRACTURE
91	81-82	22	6.7 ✓	0.0	23.8	" "
92	82-83	11	15.0	0.0	75.5	
93	83-84	11	14.4	0.0	81.5	

7473-7482 Although this interval has water saturations normally associated with gas production, it is in permeable contact with interval from 7482 to 7484, which is definitely water productive. Any completion in the interval from 7473 to 7482 would probably result in water.

CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

RECEIVED
JUN 6 1961
RESERVOIR
ENGINEERING

No. 11

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File RP-3-1441

Well CASE # 8 Core Type DIAMOND CONV. Date Report 6/5/61

Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS

County SAN JUAN State NEW MEX. Elev 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
94	7489-90	137	14.9	0.0	64.4	
95	90-91	0.52	7.7	0.0	75.4	
96	91-92	0.25	9.1	2.2	82.4	
97	92-93	19	11.2	0.0	61.6	
98	93-94	149	13.5	0.0	69.6	
99	94-95	97	13.7	1.5	71.5	
100	95-96	0.44	14.1	0.0	71.0	
101	96-97	0.32	15.3	1.3	69.2	
102	97-98	0.11	13.8	0.0	75.6	
103	98-99	0.17	15.2	0.0	77.0	
104	99-7500	128	19.1	0.0	66.0	
105	7500-01	99	16.0	0.0	68.1	
106	01-02	152	16.1	1.2	72.6	
107	02-03	201	16.7	1.2	77.4	
108	03-04	88	17.2	0.0	72.6	
109	04-05	167	17.6	0.0	73.0	
110	05-06	4.4	13.5	0.0	69.5	
111	06-07	0.68	9.1	0.0	74.6	
112	07-08	0.01	8.5	0.0	76.5	
113	08-09	0.07	8.9	0.0	72.0	
114	09-10	0.03	5.9	0.0	61.0	
115	10-11	0.38	6.9	0.0	58.0	
116	11-12	0.08	7.0	0.0	68.5	
117	12-13	0.12	7.2	0.0	85.0	

7489-7513 This interval is water productive.

EL PASO NATURAL GAS COMPANY
MOORE NO. 8
SW-24-32N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

	Depth (feet)	Permeability (md.)
	7589-90	.01
	7591-92	.01
	7593-94	.05
	7595-96	.01
	7597-98	.07
	7599-7600	.01
	7601-02	.08
	7603-04	.01
	7605-06	.01
	7607-08	.01
	7609-10	.02
	7611-12	.01
	7670-71	.03
	71-72	.05
	72-73	.48
	73-74	.01
	74-75	.01
	75-76	.07
	76-77	.03
	78-79	.01
	79-80	.09
	80-81	.01
	81-82	.11
	82-83	.17
	83-84	.08
	84-85	.01
	85-86	.02
	86-87	.01
	87-88	.04
	88-89	.01
	89-90	.01
	90-91	.29
	91-92	.07
	92-93	.02
	93-94	.01
	94-95	.01
	95-96	.02
	96-97	.02
	97-98	.12
Totals	39	2.10
Average Laboratory		.0538
Average In-Situ		.0151

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 11
CASE NO.

11

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

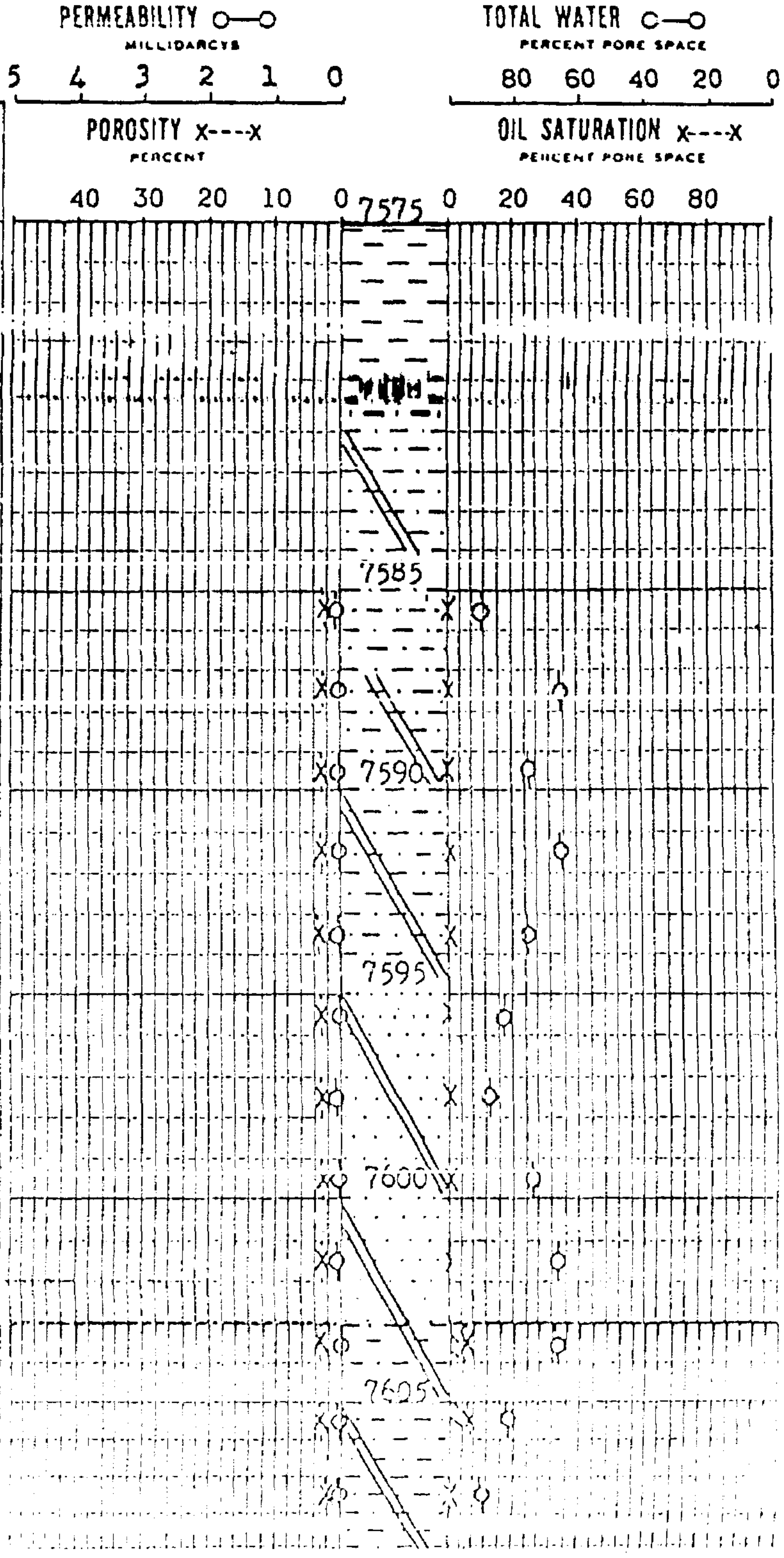
COMPANY EL PASO NATURAL GAS COMPANY DATE ON 4/23/61 FILE NO. RP-3-1425
WELL MOORE # 8 DATE OFF 5/1/61 ENGRS. McCOMAS
FIELD BASIN-DAKOTA FORMATION AS NOTED ELEV. 6556 GR
COUNTY SAN JUAN STATE N.MEXICO DRLG. FLD. WATER BASE MUD CORES DIAMOND CONV.
LOCATION SEC 24 T32N R12W REMARKS SAMPLED BY CLI AT DIRECTION OF CLIENT

SAND ░ LIMESTONE ▦ CONGLOMERATE ⁘ CHERT ▦
SHALE ▤ DOLOMITE ▱ ⫽ VERTICAL FRACTURE ☐

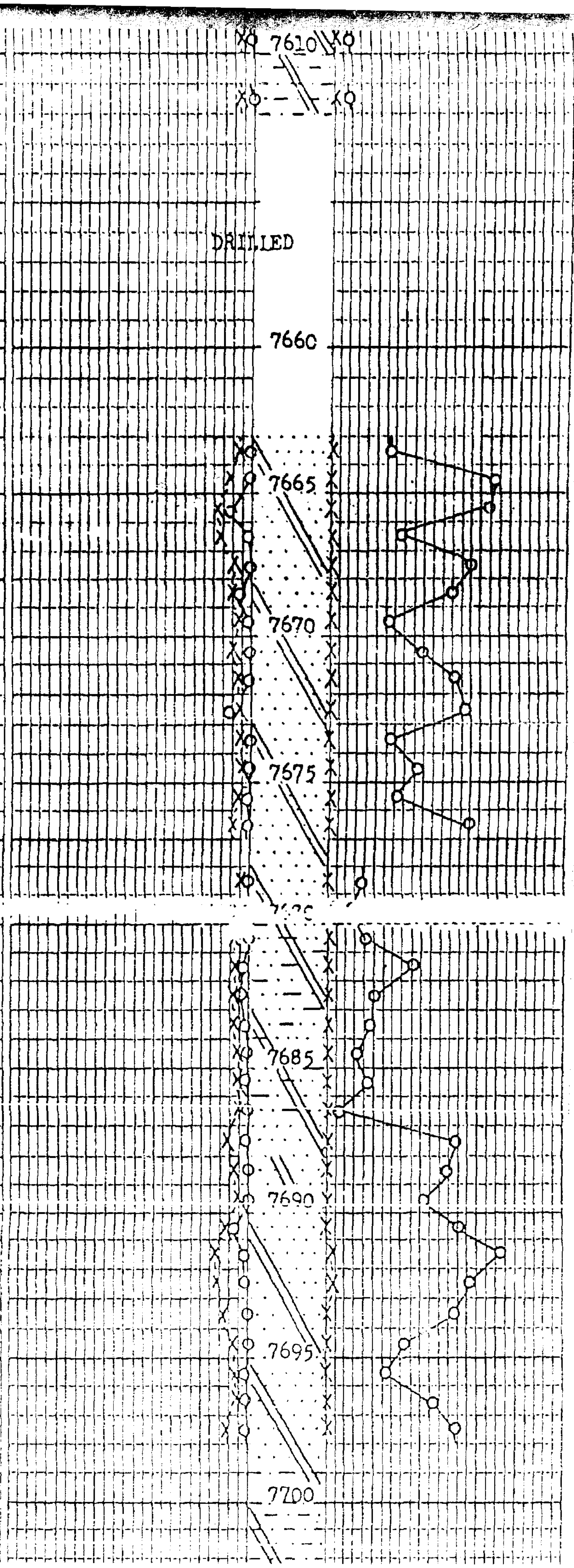
COMPLETION COREGRAPH

TABULAR DATA and INTERPRETATION

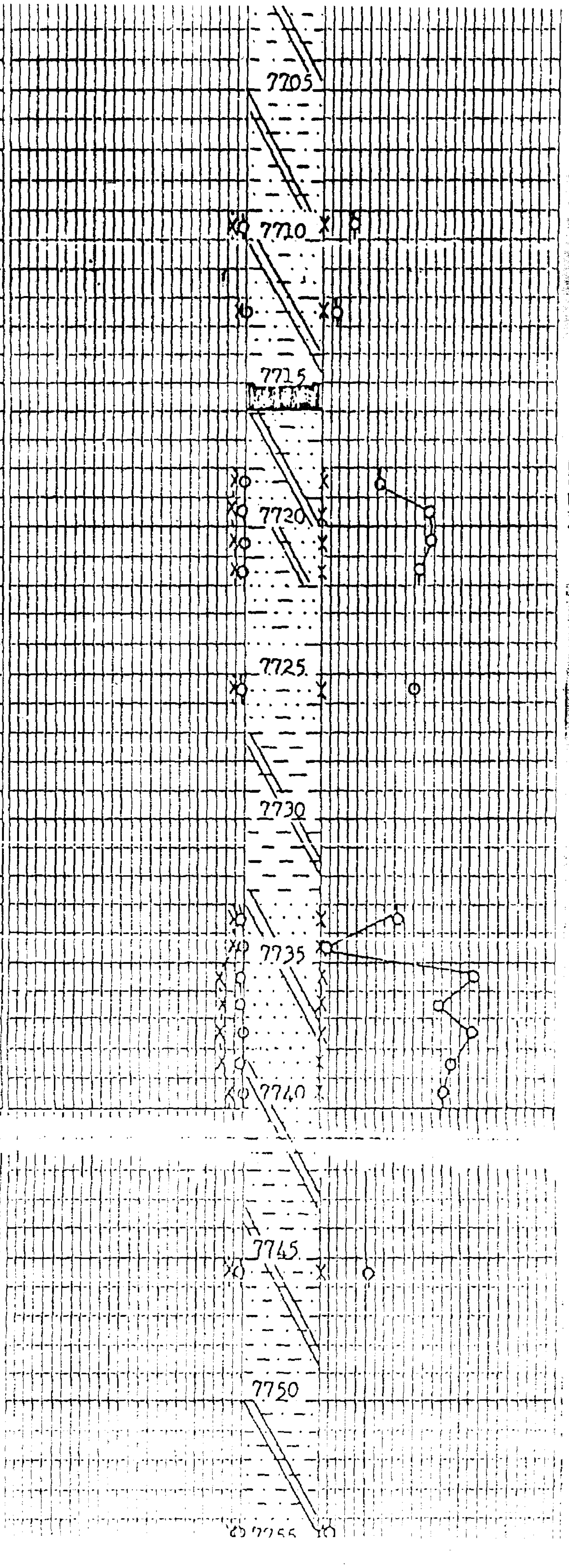
SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE			* PROD
				OIL	TOTAL WATER		
			GRANEROS				
1	7585-86	0.02	2.5	0.0	88.1		
2	7587-88	<0.01	3.1	0.0	64.7		
3	7589-90	0.01	2.9	0.0	75.9		
4	7591-92	<0.01	3.4	0.0	64.9		
5	7593-94	0.05	3.6	0.0	75.1		
6	7595-96	<0.01	3.4	0.0	82.4		
7	7597-98	0.07	3.1	0.0	87.1		
8	7599-7600	<0.01	3.0	0.0	73.4		
9	7601-02	0.08	3.0	0.0	66.7		
10	7603-04	<0.01	3.3	6.1	66.9		
11	7605-06	0.01	3.3	6.1	81.9		
12	7607-08	<0.01	1.7	0.0	88.4		



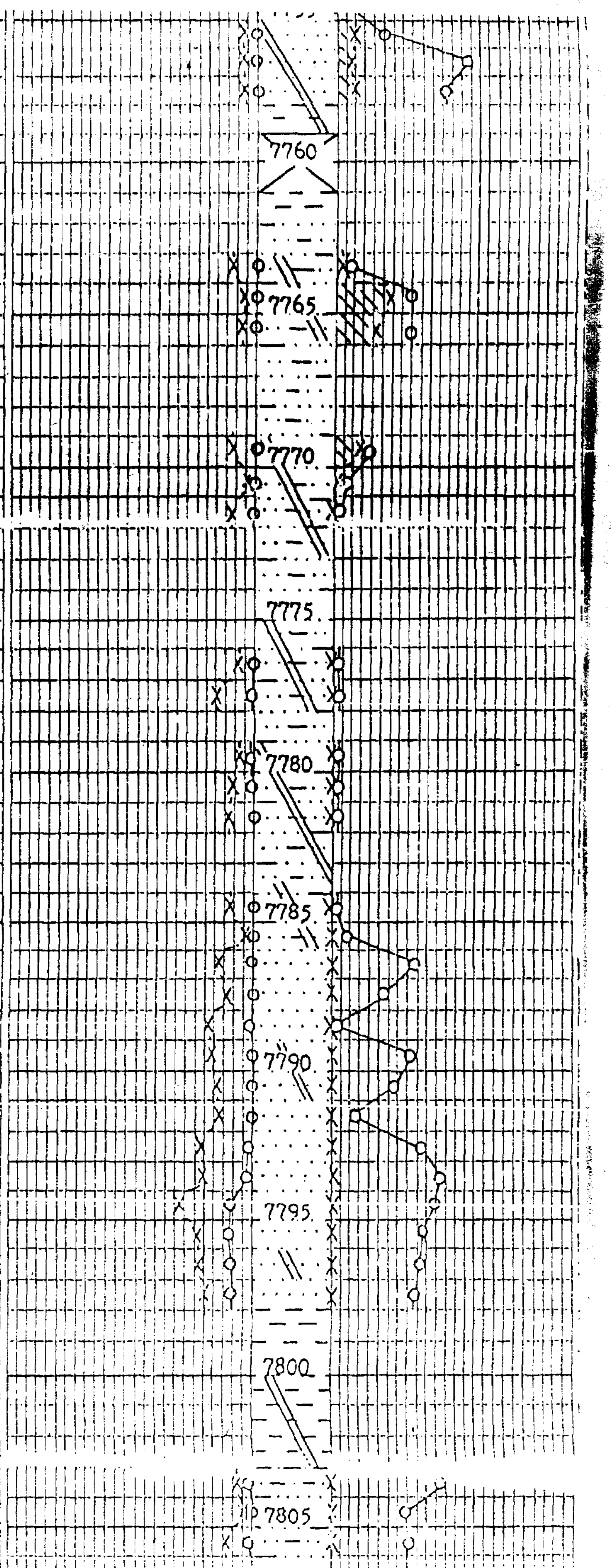
13	7609-10	0.02	2.9	0.0	93.3
14	7611-12	<0.01	3.0	0.0	93.4
			DAKOTA		
15	7663-64	0.01	2.4	0.0	75.0
16	64-65	0.03	5.2	0.0	30.6
17	65-66	0.41	7.4	0.0	32.3
18	66-67	0.10	6.6	0.0	69.5
19	67-68	0.04	4.0	0.0	40.0
20	68-69	0.26	2.5	0.0	48.1
21	69-70	0.07	2.8	0.0	75.4
22	70-71	0.03	4.0	0.0	60.0
23	71-72	0.05	2.5	0.0	47.0
24	72-73	0.48	2.8	0.0	42.9
25	73-74	0.01	2.7	0.0	74.2
26	74-75	0.01	1.9	0.0	63.2
27	75-76	0.07	2.8	0.0	71.6
28	76-77	0.03	4.0	0.0	40.0
29	7678-79	<0.01	1.3	0.0	84.7
30	79-80	0.09	[illegible]	[illegible]	[illegible]
31	80-81	0.01	3.2	0.0	84.0
32	81-82	0.11	2.2	0.0	64.0
33	82-83	0.17	2.5	0.0	80.0
34	83-84	0.08	3.3	0.0	81.5
35	84-85	0.01	2.4	0.0	87.6
36	85-86	0.02	2.3	0.0	82.7
37	86-87	<0.01	2.2	0.0	95.6
38	87-88	0.04	4.7	0.0	44.5
39	88-89	0.01	3.7	0.0	48.4
40	89-90	<0.01	2.4	0.0	58.5
41	90-91	0.29	5.0	0.0	44.0
42	91-92	0.07	7.7	2.6	26.0
43	92-93	0.02	6.6	3.0	39.5
44	93-94	0.01	4.8	0.0	45.9
45	94-95	0.01	3.0	0.0	66.7
46	95-96	0.02	2.7	0.0	74.6
47	96-97	0.02	2.2	0.0	54.5
48	97-98	0.12	4.4	0.0	45.5



49	7709-10	0.07	2.9	0.0	86.1
50	7712-13	<0.01	1.7	0.0	94.1
51	7718-19	<0.01	2.7	0.0	74.1
52	19-20	0.02	3.7	0.0	54.0
53	20-21	<0.01	3.0	0.0	53.1
54	21-22	0.02	2.8	0.0	57.2
55	7725-26	0.07	2.5	20.0	60.0
56	7733-34	0.05	1.8	0.0	66.6
57	34-35	<0.01	2.7	0.0	96.6
58	35-36	0.04	5.8	0.0	34.4
59	36-37	0.04	4.9	0.0	48.9
60	37-38	<0.01	5.7	0.0	35.0
61	38-39	0.02	5.2	0.0	44.0
62	39-40	<0.01	3.4	0.0	47.0
63	7745-46	<0.01	2.4	0.0	79.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]



64	7754-55	<0.01	2.0	0.0	95.0
65	55-56	<0.01	2.5	8.0	80.0
66	56-57	<0.01	3.3	6.1	45.5
67	57-58	<0.01	2.9	6.9	55.0
68	7763-64	<0.01	5.2	3.8	92.3
69	64-65	<0.01	2.2	22.5	68.2
70	65-66	<0.01	2.8	17.8	68.1
71	7769-70	<0.01	4.8	10.4	85.5
72	70-71	<0.01	1.8	0.0	95.0
73	71-72	0.01	4.2	0.0	97.9
74	7776-77	0.01	3.9	0.0	97.5
75	77-78	0.02	8.0	0.0	97.5
76	7779-80	0.03	3.8	0.0	97.5
77	80-81	0.03	4.5	0.0	97.9
78	81-82	<0.01	4.5	0.0	97.9
79	7784-85	0.01	5.1	0.0	98.0
80	85-86	<0.01	1.4	0.0	93.2
81	86-87	0.02	7.7	0.0	65.0
82	87-88	<0.01	5.3	0.0	78.3
83	88-89	0.05	9.4	0.0	97.6
84	89-90	0.02	8.2	0.0	67.1
85	90-91	0.01	7.6	0.0	72.4
86	91-92	0.01	7.3	0.0	89.0
87	92-93	0.10	11.5	0.0	62.6
88	93-94	0.11	10.6	1.9	54.0
89	94-95	0.41	15.3	0.0	58.2
90	95-96	0.46	11.8	0.0	60.1
91	96-97	0.44	11.5	0.0	63.5
92	97-98	0.43	10.0	0.0	65.0
[illegible]	[illegible]				
93	7803-04	0.05	2.6	0.0	54.0
94	04-05	<0.01	1.9	0.0	68.5
95	05-06	0.05	5.6	8.9	67.9

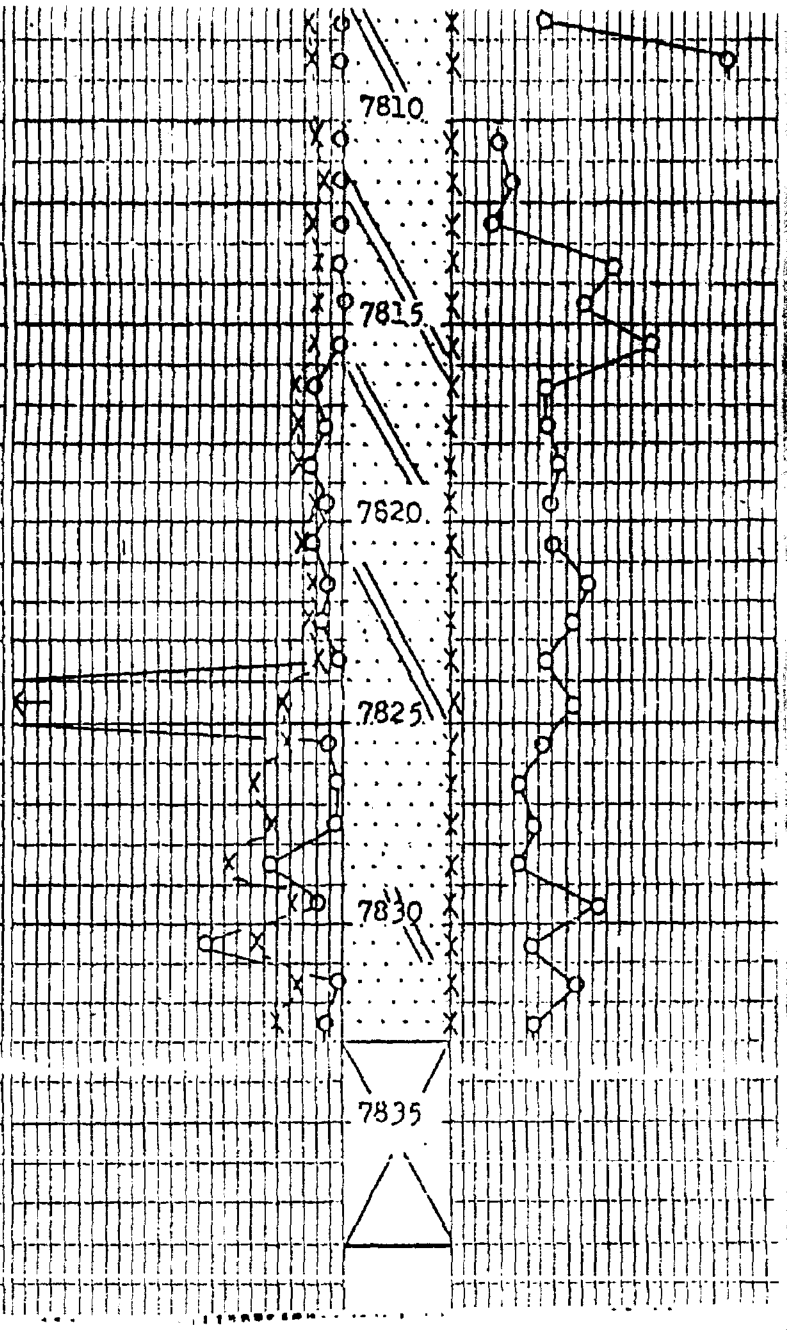


ORM F-1 COREGRAPH HEADS—TOTAL WATER

CORE LAB

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

96	7807-08	0.03	5.7	0.0	71.9
97	08-09	0.03	5.3	0.0	15.1
98	7810-11	<0.01	4.5	0.0	84.4
99	11-12	0.02	3.1	0.0	81.0
100	12-13	0.02	4.7	0.0	87.3
101	13-14	0.02	4.0	0.0	50.0
102	14-15	<0.01	4.0	0.0	59.6
103	15-16	0.02	4.3	0.0	37.1
104	16-17	0.44	7.5	2.7	69.4
105	17-18	0.29	6.9	0.0	69.5
106	18-19	0.52	6.0	0.0	66.6
107	19-20	0.21	3.8	0.0	68.2
108	20-21	0.44	5.0	0.0	68.0
109	21-22	0.23	4.2	0.0	57.0
110	22-23	0.32	5.0	0.0	61.8
111	23-24	0.05	4.0	0.0	70.0
112	24-25	7.7	8.8	0.0	61.3
113	25-26	0.21	8.3	0.0	71.0
114	26-27	0.07	13.9	0.0	79.4
115	27-28	0.12	10.9	0.0	75.2
116	28-29	1.1	17.2	0.0	78.1
117	29-30	0.37	7.9	0.0	54.4
118	30-31	2.1	13.0	0.0	74.6
119	31-32	0.02	6.6	0.0	60.5
120	32-33	0.21	10.0	0.0	74.0



BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 12
CASE NO.

PERMEABILITY, GAS AND CRUDE PRODUCTION DATA
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

					Stabilized Production Rate			
Operator/Lease	Well No.	Location	Depth	In Situ Gas Permeability (Md.)	Measured (MCFD)	Calculated at Atmospheric Pressure (MCFD)	Crude Production (BPD)	Remarks
Southland Royalty Co. East	7E	SW-14-31N-12W	7282-7448	.0011	21.6	21.7	0	Permeability calculated from pressure build-up
Southland Royalty Co. Patterson "B" Com.	1E	SW-2-31N-12W	7212-7385	.0877	224.0	224.1	0	Permeability calculated using Darcy's Law
Aztec Oil & Gas Co. Pierce	2	SW-30-31N-10W	6638-7104	.0609	208.0	208.1	0	Permeability calculated using Darcy's Law
(2) El Paso Natural Gas Co. Case	8	NE-18-31N-11W	7254-7406	.0335	--	--	--	Permeability from core data (1) In situ permeability determined to be 28% of permeability from routine core analysis
(2) El Paso Natural Gas Co. Moore	8	SW-24-32N-12W	7589-7800	.0151	--	--	--	Permeability from core data (1) In situ permeability determined to be 28% of permeability from routine core analysis

and Don C. Ward: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of ne Cores", Journal of Petroleum Technology, February, 1972, 120-124 (See Exhibit No. 8)

rmation was not tested.

12

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 13
CASE NO.

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

				Cumulative Production (1-1-80)		Remaining Reserves (1-1-80)		Ultimate Reserves	
Operator	Lease	Well No.	Location	Gas (MCF)	Oil (BBLS)	Gas (MCF)	Oil (BBLS)	Gas (MCF)	Oil (BBLS)
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper	15	NE-21-32N-12W	82,784	1,045	53,714	181	136,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Tenneco	Moore	1	NW-25-32N-12W	150,109	0	0	0	150,109	0
Tenneco	Hubbard	1	SE-25-32N-12W	430,872	0	118,134	0	549,006	0
Southland Royalty	Decker	2	NE-26-32N-12W	86,930	285	46,571	0	133,501	285
Tenneco	Moore "C"	2	NW-26-32N-12W	384,093	1,284	250,514	0	634,607	1,284
Tenneco	Moore "C"	1	SE-27-32N-12W	500,205	1,803	175,347	0	675,552	1,803
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Southland Royalty	Culpepper Martin	10	SW-32-32N-12W	402,396	3,513	352,593	690	754,989	4,203
Southland Royalty	Culpepper Martin	3	SW-33-32N-12W	256,054	1,535	361,586	1,928	617,640	3,463
Southland Royalty	Culpepper Martin	17	SE-33-32N-12W	77,114	591	1,335,936	7,636	1,411,050	8,227
Consolidat	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Benson-Mor	Plata	1	SW-30-32N-13W	183,726	0	187,451	0	371,177	0
Benson-Mo	ta	2	NW-30-32N-13W	319,414	0	302,340	0	621,754	0
Consolida	on Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolid	ya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolid	ya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron	State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consoli	American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
Delhi-Taylor	ntic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
Tenneco	antic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
Southland Royalty	Tict	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
Totals		31		5,293,695	21,781	4,428,332	24,545	9,722,027	46,326
Average				170,764	702	142,850	792	313,614	1,494

13

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0001:1,Y,GAS,5320,10,1981
0002:3.85,3.85,N,7000,N,N
0003:SRC UNNAMED NO. 1
0004:BASIN DAKOTA
0005:SAN JUAN NEW MEXICO
0006:MINIMUM ECONOMICS-103
0007:G,226,0,0,1,1,1
0008:42.76,3.11,50,10.42,7,7,14.11,70,0,146,7,19
0009:100,13.5,0,0,0,8,8,0
0010:HYP,0,300,350,0,125,END
0011:1981,4,G,121,258,1,0,END
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BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 14
CASE NO. ____________

14

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                                              SOUTHLAND ROYALTY COMPANY
                                        BEFORE TAX ECONOMICS - DETAIL REPORT                 PREPARED BY: MT
                                                                                             FILE: DATA47            DATE: 12-3-80
PROJECT:  SRC UNNAMED NO. 1                            - BASIN DAKOTA                        INITIAL INVESTMENT DATE: 04/01/1981
          SAN JUAN NEW MEXICO                          - MINIMUM ECONOMICS-103               INITIAL PRODUCTION DATE: 10/01/1981

      GROSS PRODUCTION    NET PRODUCTION      PRICES     -----------REVENUES AND TAXES M$-----------------   LEASE OPR.   INCOME M$     DEV&DR
YEAR  MBBL/YR MMCF/YR   MBBL/YR MMCF/YR   $/BBL  $/MCF    OIL     GAS     TOTAL    P.TAX   D.TAX     NET     EXP. M$    NET   DISC09%   EXP. M$

1981      0.     15.       0.     13.    42.76  3.11      2.      39.      41.      3.     01.      37.       0.       37.     35.      379.
1982      0.     42.       0.     36.    45.75  3.33      6.     121.     128.     10.     03.     115.       2.      113.     99.       00.
1983      0.     29.       0.     25.    48.96  3.56      5.      90.      95.      8.     02.      85.       2.       83.     67.       00.
1984      0.     23.       0.     20.    50.00  3.81      4.      75.      79.      6.     02.      71.       2.       69.     51.       0
1985      0.     19.       0.     16.    50.00  4.08      3.      67.      70.      6.     01.      63.       2.       61.     41.       00.
1986      0.     16.       0.     14.    50.00  4.36      3.      61.      64.      5.     01.      58.       2.       56.     35.       00.
1987      0.     14.       0.     12.    50.00  4.67      2.      58.      60.      5.     01.      54.       2.       52.     30.       00.
1988      0.     13.       0.     11.    50.00  4.99      2.      55.      57.      5.     01.      52.       2.       50.     26.       00.
1989      0.     12.       0.     10.    50.00  5.34      2.      54.      56.      4.     00.      51.       2.       49.     23.       00.
1990      0.     11.       0.      9.    50.00  5.72      2.      53.      54.      4.     00.      50.       2.       48.     21.       00.
1991      0.     10.       0.      9.    50.00  6.12      2.      52.      54.      4.     00.      49.       2.       47.     19.       00.
1992      0.      9.       0.      8.    50.00  6.55      2.      52.      53.      4.     00.      49.       2.       47.     17.       00.
1993      0.      9.       0.      7.    50.00  7.00      1.      52.      53.      4.     00.      49.       2.       47.     16.       00.
1994      0.      8.       0.      7.    50.00  7.49      1.      52.      54.      4.     00.      49.       2.       47.     15.       00.
1995      0.      8.       0.      7.    50.00  8.02      1.      53.      54.      4.     00.      50.       2.       48.     14.       00.
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S-TOT     1.    237.       1.    205.    48.67  4.57     38.     934.     973.     78.     11.     883.      31.      852.    509.      379.
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AFTER     0.    113.       0.     98.    50.00 10.19     19.    1000.    1019.     81.     00.     937.      50.      887.    118.       00.
-------------------------------------------------------------------------------------------------------------------------------------------------
TOTAL     1.    350.       1.    303.    49.10  6.39     57.    1934.    1991.    159.     11.    1821.      81.     1739.    627.      379
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 PRICE ASSUMPTIONS        OIL      GAS      PRODUCTION                                          OWNERSHIP

 INITIAL PRICE:         $42.76    $3.11  PRODUCING DEV. WELLS-GROSS/NET:      1 / 1.00       W.I. BEFORE/AFTER PAYOUT:100.00%\100.00%
 AVERAGE PRICE:         $49.10   $ 6.39  DRY DEV. WELLS-GROSS/NET:            0 / 0.00       N.I. BEFORE/AFTER PAYOUT: 86.50%\ 86.50%
 MAXIMUM PRICE:         $50.00   $10.42  INITIAL DAILY PRODUCTION-                           REVERT. INT. AMOUNT (M$):  $000.\ 0.0YRS
 AVG. ESC.TO MAXM.       7.00%    7.00%            .TOTAL NET:             01.BBLS    151.MCF   OPERATED:                        YES
                                                    GROSS/WELL:            01.BBLS    174.MCF
 COST ASSUMPTIONS                        FLAT LIFE:                            5.5 YRS       TANGIBLE INVEST. (M$):      $121.
 INITIAL LOE/WELL/MO:        $146.       PRODUCTION LIFE:                     36.9 YRS       INTANGIBLE INVEST. (M$):    $258.
 ESCALATION RATE:            7.00%       AVG. PRODUCTION DECLINE/YR.:          7.52 %
 MAXIMUM LOE/WELL/MO:        $185.       YIELD (BBLS/MMCF):               3.9MAX.    3.9MIN.  DE-REGULATION TAX DATA
 PROD. TAX RATE:          8.00%  8.00%   AVG. WELL DEPTH (Ft.):         7000                  BASE PRICE/BBL.: $14.1  TAX RATE: 70.0%
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                              SOUTHLAND ROYALTY COMPANY
                              DRILLING ECONOMICS SUMMARY     PREP. BY: MT
                                         FILE: DATA47         DATE: 12-3-80
PROJECT: SRC UNNAMED NO. 1              Initial Investment Date: 04/01/1981
         BASIN DAKOTA                   Initial Production Date: 10/01/1981
         SAN JUAN NEW MEXICO
         MINIMUM ECONOMICS-10

1. NOT DISCOUNTED (BEFORE INCOME TAX)
     Net Income Before Capital:  $1739.   Risk Cost:  $226.    Ratio:    7.7
     Profit After Capital:       $1360.   Capital:     $379.   Ratio:  3.6
2. RISK PARAMETERS
     Trap: 1.00      Reservoir: 1.00   Hydrocarbon: 1.00   Total(R.F.): 1.00
3. OBJECTIVE TEST
     Discounted @7% Before Tax Net Income:     $627.
                        Adjusted For Risk:     $627.
     CAPITAL:(Risk Cost*(1-R.F.) + R.F.*Disc. Develop. Cost)*1.25:     $474.
                              Above Or Below SRC Objective:    $153.
4. PAYOUT (yrs)
     Before Tax:  5.05    ✓           After Tax: 5.74
5. AFTER TAX RATE OF RETURN
     No Risk:     15.53    ✓          Risk Adjusted:  15.53
6. COST PER EQUIVALENT BBL & MCF        $7.34/BBL $1.22/MCF
7. RISK FACTOR SENSITIVITY
                          RISK        RISK ADJUSTED      ABOVE OR BELOW
                          FACTOR      AFTER TAX ROR      SRC OBJECTIVE
                           0.80           13.2               $66.
                           0.60           10.5               $21.-
                           0.40            7.0              $108.-
                           0.20            2.0              $195.-
                           0.10            0.1              $239.-
                           0.05            0.1              $261.-
                Minimum:   0.95           15.0              $132.
8.PROJECT DATA:                                       RISK COSTS (M$) :
     Total Life (yrs):       36.9                       Dryhole:    226.
     Flat Life (yrs):         5.5                       Acreage:     00.
     W.I. Before/After Payout:  100.000%I100.000%       Seismic:     00.
     N.I. Before/After Payout:   86.500%I 86.500%       Total:      226.
     Revert. Int. Amount (M$):       0.
     Excise Tax (M$):               11.
     Net Oil Reserves (MBBLS):      01.
     Net Gas Reserves (MMCF):      303.
     Gross Producing Wells:         1.
     Gross Develop. Dry Holes:      0.
     Depth (ft):                  7000
9. UNIT PRICING (GAS)
     Initial/Maximum:              $3.11/ $10.42
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0001:1,Y,GAS,2280,10,1981
0002:3.85,3.85,N,7000,N,N
0003:SRC UNNAMED NO. 1
0004:BASIN DAKOTA
0005:SAN JUAN NEW MEXICO
0006:MINIMUM ECONOMICS-2 X 103
0007:G,226,0,0,1,1,1
0008:42.76,6.22,50,10.42,7,7,14.11,70,0,146,7,19
0009:100,13.5,0,0,0,8,8,0
0010:HYP,0,300,150,0,125,END
0011:1981.4,G,121,258,1,0,END
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BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 15
CASE NO.

15

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                                            SOUTHLAND ROYALTY COMPANY
                                     BEFORE TAX ECONOMICS - DETAIL REPORT                PREPARED BY: MT
                                                                                         FILE: DATA48         DATE: 12-3-80
PROJECT:  SRC UNNAMED NO. 1                    - BASIN DAKOTA                            INITIAL INVESTMENT DATE: 04/01/1981
          SAN JUAN NEW MEXICO                  - MINIMUM ECONOMICS-2 X 103               INITIAL PRODUCTION DATE: 10/01/1981

      GROSS PRODUCTION    NET PRODUCTION      PRICES      -------------REVENUES AND TAXES M$--------------   LEASE OPR.   INCOME M$     DEV&EQP
YEAR  MBBL/YR MMCF/YR   MBBL/YR MMCF/YR   $/BBL  $/MCF    OIL     GAS     TOTAL    P.TAX  D.TAX     NET      EXP. M$    NET  DISC@9%   EXP. M$

 1981      0.      6.        0.      6.   42.76  6.22      1.      35.      36.      3.     00.      32.         0.       32.     31.      379.
 1982      0.     21.        0.     18.   45.75  6.66      3.     118.     121.     10.     01.     110.         2.      108.     95.       00.
 1983      0.     15.        0.     13.   48.96  7.12      3.      95.      98.      8.     01.      89.         2.       87.     70.       00.
 1984      0.     13.        0.     11.   50.00  7.62      2.      83.      85.      7.     01.      77.         2.       75.     55.       00.
 1985      0.     11.        0.      9.   50.00  8.15      2.      75.      77.      6.     01.      70.         2.       68.     46.       00.
 1986      0.      9.        0.      8.   50.00  8.72      2.      70.      72.      6.     01.      65.         2.       63.     39.       00.
 1987      0.      8.        0.      7.   50.00  9.33      1.      67.      68.      5.     01.      62.         2.       60.     34.       00
 1988      0.      7.        0.      6.   50.00  9.99      1.      65.      66.      5.     00.      60.         2.       58.     30.       00.
 1989      0.      7.        0.      6.   50.00 10.42      1.      62.      63.      5.     00.      58.         2.       55.     27.       00
 1990      0.      6.        0.      5.   50.00 10.42      1.      57.      58.      5.     00.      53.         2.       51.     22.       00.
 1991      0.      6.        0.      5.   50.00 10.42      1.      53.      54.      4.     00.      49.         2.       47.     19.       00.
 1992      0.      5.        0.      5.   50.00 10.42      1.      49.      50.      4.     00.      46.         2.       44.     16.       00.
 1993      0.      5.        0.      4.   50.00 10.42      1.      46.      47.      4.     00.      43.         2.       41.     14.       00.
 1994      0.      5.        0.      4.   50.00 10.42      1.      44.      45.      4.     00.      41.         2.       39.     12.       00.
 1995      0.      5.        0.      4.   50.00 10.42      1.      41.      42.      3.     00.      39.         2.       37.     11.       00.
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S-TOT      0.    130.        0.    112.   48.84  8.55     21.     960.     981.     78.     06.     896.        31.      865.    522.      379.
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AFTER      0.     20.        0.     17.   50.00 10.42      3.     182.     185.     15.     00.     171.        11.      159.     36.       00.
-------------------------------------------------------------------------------------------------------------------------------------------------
TOTAL      1.    150.        0.    130.   49.00  8.80     24.    1142.    1167.     93.     06.    1067.        42.     1025.    558.      379.
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PRICE ASSUMPTIONS       OIL       GAS     PRODUCTION                                          OWNERSHIP

INITIAL PRICE:         $42.76    $6.22  PRODUCING DEV. WELLS-GROSS/NET:     1 / 1.00      W.I. BEFORE/AFTER PAYOUT:100.00%‡100.00%
AVERAGE PRICE:         $49.00   $ 8.80  DRY DEV. WELLS-GROSS/NET:           0 / 0.00      N.I. BEFORE/AFTER PAYOUT: 86.50%‡ 86.50%
MAXIMUM PRICE:         $50.00   $10.42  INITIAL DAILY PRODUCTION-                         REVERT. INT. AMOUNT (M$):  $000.‡ 0.0YRS
AVG. ESC.TO MAXM.       7.00%    7.00%            .TOTAL NET:            00.BBLS   65.MCF    OPERATED:                     YES
                                                   GROSS/WELL:           00.BBLS   75.MCF
COST ASSUMPTIONS                        FLAT LIFE:                             5.5 YRS      TANGIBLE INVEST. (M$):      $121.
INITIAL LOE/WELL/MO:      $146.         PRODUCTION LIFE:                      19.3 YRS      INTANGIBLE INVEST. (M$):    $258.
ESCALATION RATE:            7.00%       AVG. PRODUCTION DECLINE/YR.:          10.02 %
MAXIMUM LOE/WELL/MO:      $185.         YIELD (BBLS/MMCF):                 3.9MAX.    3.9MIN.  DE-REGULATION TAX DATA
PROD. TAX RATE:         8.00%  8.00%    AVG. WELL DEPTH (Ft.):             7000               BASE PRICE/BBL.: $14 1   TAX RATE: 70.0%
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                                SOUTHLAND ROYALTY COMPANY
                                DRILLING ECONOMICS SUMMARY    PREP. BY: MT
                                       FILE: DATA48         DATE: 12-3-80
PROJECT: SRC UNNAMED NO. 1             Initial Investment Date: 04/01/1981
         BASIN DAKOTA                  Initial Production Date: 10/01/1981
         SAN JUAN NEW MEXICO
         MINIMUM ECONOMICS-2

1. NOT DISCOUNTED (BEFORE INCOME TAX)
     Net Income Before Capital:  $1025.   Risk Cost:  $226.    Ratio:    4.5
     Profit After Capital:        $646.   Capital:    $379.    Ratio:  1.7
2. RISK PARAMETERS
     Trap: 1.00      Reservoir: 1.00   Hydrocarbon: 1.00   Total(R.F.): 1.00
3. OBJECTIVE TEST
     Discounted @9% Before Tax Net Income:      $558.
                       Adjusted For Risk:       $558.
     CAPITAL:(Risk Cost*(1-R.F.) + R.F.*Disc. Develop. Cost)*1.25:     $474.
                                 Above Or Below SRC Objective:     $84.
4. PAYOUT (yrs)
     Before Tax:  4.89               After Tax: 5.39
5. AFTER TAX RATE OF RETURN
     No Risk:       15.23            Risk Adjusted:  15.23
6. COST PER EQUIVALENT BBL & MCF       $17.13/BBL $2.86/MCF
7. RISK FACTOR SENSITIVITY
                              RISK         RISK ADJUSTED    ABOVE OR BELOW
                              FACTOR       AFTER TAX ROR    SRC OBJECTIVE
                              0.80             12.6             $11.
                              0.60              9.3             $62.-
                              0.40              4.7            $136.-
                              0.20              0.1            $209.-
                              0.10              0.1            $246.-
                              0.05              0.1            $264.-
                   Minimum:   0.97             15.0             $75.
8.PROJECT DATA:                                       RISK COSTS (M$) :
     Total Life (yrs):       19.3                          Dryhole:   226.
     Flat Life (yrs):         5.5                          Acreage:    00.
     W.I. Before/After Payout: 100.000%I100.000%          Seismic:    00.
     N.I. Before/After Payout:  86.500%I 86.500%          Total:     226.
     Revert. Int. Amount (M$):     0.
     Excise Tax (M$):              6.
     Net Oil Reserves (MBBLS):    00.
     Net Gas Reserves (MMCF):    130.
     Gross Producing Wells:        1.
     Gross Develop. Dry Holes:     0.
     Depth (ft):                7000
9. UNIT PRICING (GAS)
     Initial/Maximum:             $6.22/ $10.42
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ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Drilling and completions costs		378,560.00
Operating costs ($/well-month)		146.00
Depth (feet)		7,050.00
Southland Royalty working interest (%)		100.00
Royalty interest (%)		13.50
Date of initial production		10-1-81
Initial production rate (MCFD)	103 case	150
	2 x 103 case	75
Liquid yield (BBLS/MMCF)		3.85
Fully adjusted gas price as of 10-1-81 ($/MCF)	103 case	3.11
	2 x 103 case	6.22
Oil price as of 10-1-81 ($/BBL)		42.76
Maximum gas price ($/MCF)		10.42
Maximum oil price ($/BBL)		50.00
Rate of price escalation (%)		7.00
Severance Tax (%)		8.00
Deregulation Tax data	Base Oil price ($/BBL)	14.11
	Tax Rate (%)	70.00

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 16
CASE NO.

16

SOUTHLAND ROYALTY COMPANY
AUTHORITY FOR EXPENDITURE

— AFE —

☐ ORIGINAL
☐ SUPPLEMENTAL

COMPANY 01 AFE NAME SRC - Unnamed No. 1 DATE 12-2-80
REC. I.D. 01 PROSPECT NAME ______ CODE ______ SEQ. 000 ADD

COST CENTER	PROJECT	SUB-PROJECT	AFE NO.	DISTRICT
☐ EXPLORATION	San Juan Basin			Farmington
☒ PRODUCTION	170			3025

01 ☐ DRILLING
02 ☐ WILDCAT
03 ☒ DEVELOPMENT
04 ☐ RECOMPLETION
05 ☐ PLUG & ABANDON
06 ☐ L & W EQUIPMENT
07 ☐ CONSTRUCTION
08 ☐ SECONDARY RECOVERY
09 ☐ LEASEHOLD PURCH
10 ☐ FARM-IN
11 ☐ GEOPHYSICAL
12 ☐ DHC OR BHC
13 ☐ PROD PROP PURCH
14 ☐ WORKOVER
99 ☐ OTHER

PROPERTY NO. ______ NAME SRC - Unnamed
WELL NO. 1 NAME Unnamed EST. TOTAL DEPTH 7050'
STATE New Mexico CODE 30 COUNTY San Juan CODE 045
FIELD Basin Dakota
LOCATION T32N, R12W

FORMATION Dakota
OBLIGATIONS ______
LOCATION MEETS ☐ STATE RULES ☒ FIELD RULES, FIELD SPACING 320 ACRES
THIS WELL 320 ACRES
IF JOINT INTEREST PROJECT SUBJECT TO ☐ CARRIED INT ☐ NET PROFIT INT
RIGHT TO CONVERT TO W.I. ☐ OPERATING OWNER & W.I. SRC - 1.0000
JOINT OPERATING AGREEMENT NO. ______
COMPANY W.I. 1.0000 COMPANY REVENUE INTEREST .865

COMPLETED COST				DRY HOLE COST			
	TOTAL	CO-OWNER	CO NET		TOTAL	CO-OWNER	CO NET
I.D.C.	257,560		257,560	I.D.C.	184,180		184,180
TANGIBLE	121,000		121,000	TANGIBLE	41,440		41,440
L. EQUIP							
				TOTAL	225,620		225,620
TOTAL	378,560		378,560	LESS: DHC			
EXPLORATION, ETC COST				TOTAL	225,620		225,620
				RETIREMENT COST			
				REMOVAL			
				SALV/REC			
				NET COST			

REASON FOR EXPENDITURE Drill and complete a Dakota well.

PROPOSED STARTING DATE __/__/__ ESTIMATED COMPLETION DATE __/__/__
LEASE EXPIRATION DATE __/__/__ DRILLING OBLIGATION DATE __/__/__

APPROVED ☐ REJECTED ☐ IN BUDGET YES ☐ NO ☐ BUDGET # ______

DISTRICT PRODUCTION DATE	F. W. TITLE & RECORD CLEARANCE DATE	EXECUTIVE APPROVAL DATE	F. W. FINANCIAL DATE
DISTRICT EXPLORATION DATE	V. P. PRODUCTION DATE	CO-OWNER DATE	

Mar

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 17
CASE NO. ______

17

AUTHORIZATION FOR EXPENDITURE

SOUTHLAND ROYALTY COMPANY
1000 FORT WORTH CLUB TOWER
FT. WORTH, TEXAS 76102

COMPANY NO 01

RECORD ID 02

SEQ 000

AFE NUMBER ______

ADD A CHANGE ___ DELETE ___

PROPERTY NUMBER ___-_________-___

AFE DATE 12/2/80

NAME SRC - Unnamed No. 1

ORIGINAL O SUPPLEMENTAL ___ PRODUCER ___ DRY HOLE ___ SRC OPERATOR Y MANUAL ___

AUTHORITY IS REQUESTED TO: Drill and complete a Dakota well.

WILDCAT ___ DEV. D

LOCATION: T32N, R12W, San Juan County, New Mexico

FOOTAGE		TANGIBLE - 249	ESTIMATED COST PRODUCING	ESTIMATED COST DRY HOLE
	01 01	Conductor or Drive Pipe	$	$
200'	01 02	Casing 9 5/8", 32.3#, H-40	2,940	2,940
4650'	03	7", 23.0#, K-55	49,200	36,900
1900'	04	4 1/2", 10.5#, K-55	10,130	
350'	05	4 1/2", 11.6#, K-55	2,030	
	06			
	07			
	08			
7000'	02 09	Tubing 2 3/8", 4.7#, J-55	21,560	
	03 10	Wellhead	8,840	1,600
	04 11	Packer		
	04 12	Artificial Lift		
	05 13	Tank Battery	22,270	
	10 14	Other Equipment Liner Hanger	4,030	
	15	TOTAL TANGIBLE 100%	$121,000	$ 41,440
	16	SRC 1.0000 %	$121,000	$ 41,440
		INTANGIBLE - 248		
	01 17	Drilling 7050' ft. @ $ 14.00 /ft.	98,700	98,700
	01 18	Rig, Day Work 2 Days @ $ 4,700.00 /day	9,400	9,400
	01 19	Rig Moving Costs	2,900	1,200
	01 20	Completion Rig 3 Days @ $ 3,650.00 /day	10,950	
	02 21	Roustabout & Miscellaneous Labor	5,000	1,500
	03 22	Auto, Trucking, Barge, Tug	5,350	4,500
	01 23	Roads, Canals, Location, Damages, Cleanup	6,000	6,000
	05 24	Mud, Oil, Water, Chemicals	15,500	13,500
	06 25	Drill Stem Tests		
	06 26	Electric Logs & Bond Logs	10,060	10,060
	07 27	Cement, Centralizer, Scratchers, Service	12,510	7,590
	08 28	Bits, Fuel	4,250	1,500
	08 29	Rental Equipment	7,710	4,730
	09 30	Core & Analyses		
	09 31	Bottle Tests & Sidewall Cores		
	09 32	Perforate	6,660	
	09 33	Acid & Frack	27,500	
	09 34	Geological & Engineering		
	09 35	Mud Logger	600	600
	10 36	Cost of Control Insurance (SRC Only)		
	10 37	Miscellaneous & Unforseen 15% Contingency	33,470	23,900
	11&12 38	District & Overhead Expense	1,000	1,000
	39	TOTAL INTANGIBLE 100%	$257,560	$184,180
	40	SRC 1.0000 %	$257,560	$184,180
	41	GRAND TOTAL COSTS	$378,560	$225,620
	42	SRC 1.0000 %	$378,560	$225,620

AUTHORIZATION REQUESTED

____

AUTHORIZATION APPROVED

BY: ______________________

DATE: ______________________

I

GEOGRAPHICAL AND GEOLOGICAL DESCRIPTION

The recommended Dakota area is located in extreme north central San Juan County, New Mexico, adjacent to the Colorado state line and is in the northwestern portion of the San Juan Basin near the Hogback Monocline. The proposed area includes the following:

1.	T32N-R10W	All sections
2.	T32N-R11W	All sections except 28, 29, 30, 31, 32 and 33
3.	T32N-R12W	All sections except 34, 35 and 36
4.	T32N-R13W	All sections
5.	T31N-R10W	All sections
6.	T31N-R11W	Sections 1, 12, 13, 22, 23, 24, 25, 26, 27, 34, 35 and 36 only

This area is shown on Exhibit No. 1.

Exhibit No. 2 is a type log which shows the base of the Mancos, the Greenhorn, the Graneros and the Dakota formations. The vertical limits of the Baskin Dakota gas pool have been defined by the New Mexico Conservation Division to be from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation. The Graneros and first Dakota zones are the producing zones in the Basin Dakota Field. The other Dakota zones and the upper Morrison zone have very low permeability. Production from these zones has been limited to date.

The sediments of the Dakota interval were formed during late Cretaceous time. The Dakota is bounded by an uncomformable contact with the Jurassic Morrison below and is gradational with the Cretaceous Mancos shale above and is found at an average dept of 7050 feet. The gross thickness of the formation varies from 200 to 300 feet.

Deposition of the Dakota sediments occurred during a regression of the late Cretaceous sea. This regression resulted in the following sequence of depositional environments from the base upward: 1. Braided stream sandstone; 2. Meandering stream complex (with minor associated coals); 3. Coastal shale; 4. Coastal sandstone. The lower two environments contain sands of minor areal extent whereas the coastal sandstones have significant extent and are seen as northwest-southeast trending linear sand bodies reflecting their beach and off-shore bar depositional history. These upper Dakota sands appear to be the primary Dakota reservoirs.

The Dakota sands are light to dark mottled gray, fine to very fine-grained quartz sands. Silt and clay-sized matrix material can form a significant percentage of the bulk-rock composition. Because the matrix fraction tends to greatly reduce the effective permeability of the reservoir, natural and induced fractures are necessary for production from the Dakota reservoir.

Exhibit Nos. 3 and 4 are cross sections that show the continuity of the Dakota zones across the area of this application. Cross section A-A' shows sand development in a North-South direction while cross-section B-B' shows sand development in a northwest-southeast direction. The permeability of the zones in the area under consideration is lower than in more productive areas such as T31N-R12W. This is indicated by the poor performance of the wells in the proposed area compared to the wells located in T31N-R12W. This is shown by Exhibit No. 1, which is a completion and production map showing both 1979 annual oil and gas production and the cumulative oil and gas production as of January 1, 1980.

II

GEOLOGICAL AND ENGINEERING DATA

PERMEABILITY

Average in situ permeability for the Dakota formation is 0.1 md or less throughout the recommended area. Several methods were used to determine the average in situ permeability. Each method is described below, and the resulting value of permeability is provided.

1. Pressure Buildup Analysis. In order to determine in situ permeability by this method, it is necessary to produce the well prior to stimulation until it stabilizes then shut it in for a pressure build up with a pressure recorder at the bottom of the hole. This pressure data is then plotted against a time ratio and the slope of the straight line portion of the curve is determined. This slope is used to calculate permeability.

This method was used to determine an average in situ permeability of 0.0011 md in the Southland Royalty Company East No. 7E (See Exhibit No. 5).

2. Darcy's Law Analysis. In order to determine in situ permeability by this method, it is necessary to produce the well under pre-stimulation conditions until both the rate and flowing pressure stabilize. The well is then shut in and the stabilized shut-in pressure determined. With this and other known geological and engineering data, the permeability is calculated using the Darcy flow equation.

This method was used to determine in situ permeability values of 0.0877 and 0.0609 md in the Southland Royalty Company

Patterson "B" Com. No. 1E and Pierce No. 2, respectively (See Exhibit Nos. 6 and 7).

3. Core Analysis. Laboratory permeability is determined by employing coring equipment (bit and barrel) to cut and recover a portion of the reservoir rock. Small plugs are then cut from the rock at one-foot intervals, and the permeability is measured at laboratory conditions. Permeability at reservoir conditions is always less than it is at laboratory conditions because overburden pressure is greater than the pressure used in the laboratory. The higher pressure causes the permeability to be lower. The water that is present in the reservoir rock also causes the in situ permeability to be lower. A paper has been written that presents a method of determining the relationship between laboratory and in situ or reservoir permeability (See Exhibit No. 8).

This method was used to determine average in situ permeability values of 0.0335 and 0.0151 md in the El Paso Natural Gas Company Case No. 8 and Moore No. 8, respectively (See Exhibit Nos. 10 and 11). The laboratory permeabilities for the two wells are 0.1195 and 0.0538, respectively. This data is also shown on Exhibit Nos. 10 and 11. These two 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. The data from these summary tables was used in calculating the average permeability values. This method of determining in situ permeability is explained in Exhibit No. 9.

STABILIZED PRODUCTION RATES

Stabilized production rates were taken on three of the five test wells, the Southland Royalty Company East No. 7E, Patterson "B" Com. No. 1E and Pierce No. 2. The flow rates for

East No. 7E and Patterson "B" Com. No. 1E were taken before stimulation while the flow rate for Pierce No. 2 was taken after stimulation. The production rates were measured at pressures other than atmospheric. These rates were used to determine permeability. The production rates were then calculated at atmospheric conditions by employing the Darcy flow equation. The maximum gas production rate permitted under the tight formation guideline is 290 MCFD for the depth interval 7000-7500 feet. These three wells meet this guideline as shown on Exhibit No. 12. The other two wells, the El Paso Natural Gas Company Cas No. 8 and Moore No, 8, were dry holes and, therefore, did not produce.

OIL PRODUCTION RATES

The three productive test wells did not produce enough oil to measure during the production test. Daily oil production is, therefore, shown to be zero on Exhibit No. 12. None of the wells offsetting the three wells currently produce in excess of five barrels of oil per day as can be seen on Exhibit No. 1; therefore, the daily oil production limit is satisfied.

III

WELLS IN RECOMMENDED FORMATION

Exhibit No. 1 is a completion and production map which shows all of the wells that have produced from the Dakota formation in the geographical area of this application. The map also contains the 1979 annual gas and oil production and the cumulative gas and oil production as of January 1, 1980, as stated previously.

IV

PROTECTION OF FRESH WATER

Existing state and federal regulations will assure that development of the Dakota formation will not adversely affect or impair any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations occur in the area of interest. These are: 1. San Jose, 2. Nacimiento and 3. Ojo Alamo. The three formations occur from the surface of the ground to an average depth of 1200 feet.

In New Mexico, the Oil Conservation Division is responsible for protecting fresh water while drilling, completing and producing oil and gas wells as provided by Rule 106. This rule requires the casing to be designed to seal off water bearing formations thus separating them from oil and gas bearing formations. Additionally, federal regulations provide for protection of fresh water in oil and gas related activities.

The Dakota formation requires large fracture treatments during completion to provide favorable economics since it is a very tight formation. Fresh water protection is adequate even with these large stimulations. The top of the upper Dakota producing zone is approximately 5800 feet below the deepest fresh water zone thus providing additional insurance that no existing fresh water will be contaminated.

Together, state rules in 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 proposed tight sand area.

V

OTHER RELEVANT INFORMATION

RESERVES AND ECONOMICS

The average estimated ultimate gas recovery for each of the 31 wells in the area of interest that have produced is 313,614 MCF (See Exhibit No. 13). Fifteen of the wells are expected to have ultimate recoveries of less than 200,000 MCF. Gas reserves of 350,000 MCF are required to provide minimum standard economics of 15% rate of return after federal income tax at current 103 prices (See Exhibit No. 14) while gas reserves of only 150,000 MCF are required to provide minimum standard economics at 200% of current 103 prices (See Exhibit No. 15). As indicated, increased prices are necessary to justify drilling Dakota wells in the proposed area because the anticipated recovery is expected to be less than 350,000 MCF, thus causing the wells to be uneconomical at current prices.

Exhibit No. 16 is a tabulation showing the assumptions used in making the economic calculations. Exhibit No. 17 is an Authority for Expenditure showing the cost to drill and complete a Dakota well in the subject area.

MISCELLANEOUS INFORMATION

In addition to completion and production data, Exhibit No. 1 contains the following:

1. Location of cross sections A-A' and B-B'.
2. Location of test wells for which permeability, gas production and oil production rates are submitted.
3. Location of wells that were completed in the Dakota formation but never produced after the initial potential was taken.

4. Location of dry holes that have been drilled in the Dakota formation in the recommended area.

There are two wells in the proposed area that were completed in the Dakota formation but never produced after the initial potential was taken. There are five dry holes in the subject area that were drilled to test the Dakota formation. The failure to make successful Dakota completions in these seven wells provides additional indication that the Dakota formation exhibits very low permeability in the area under consideration.

Three of the test wells, Patterson "A" Com. No. 1E (SW-2-31N-12W), East No. 7E (SW-14-31N-12W) and Case No. 8 (NE-18-31N-11W), are not located in the proposed area. The wells are located near the area, however, where production is more prolific as shown by Exhibit No. 1. The fact that these wells meet the necessary guidelines even in a more productive area indicates that the proposed area will also meet the necessary guidelines.

VI

CONCLUSION

It has been shown in this recommendation that the Dakota formation in the proposed area meets the guidelines necessary to qualify the area for tight formation designation. These include the following:

1. The in situ permeability is less than 0.1 md.
2. The stabilized gas production rate (290 MCFD in the interval 7000-7500 feet) is less than the maximun that is permitted.
3. No well will produce more than five barrels of oil per day.

4. Any fresh water in the area will be adequately protected while the wells are being drilled, completed and produced.

In addition, it has been shown that Dakota wells drilled and completed in the area will not be economical at 103 prices. Added price incentive is, therefore, necessary before the gas reserves in the area can be developed and produced. If the incentive price is allowed to be received for the wells drilled in the recommended area, it is estimated that Southland Royalty Company will recover an additional 14 BCF of gas reserves that would not otherwise be available to existing gas markets.

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

COMMISSION HEARING

IN THE MATTER OF:

Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

CASE 7361

BEFORE: Commissioner Ramey
Commissioner Arnold

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

INDEX

HARLAN THOMPSON

MR. RAMEY: Call next Case 7361.

MR. PEARCE: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

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

I have one witness who needs to be sworn.

(Witness sworn.)

HARLAN THOMPSON

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

DIRECT EXAMINATION

BY MR. CARR:

MR. CARR: May it please the Commission, at this time we would request that the record, including all Southland exhibits offered in the original hearing in Case 7116, held on December 30, 1980, be incorporated into the record of this hearing.

MR. RAMEY: Without objection, why, the Commission will incorporate the record in Case 7116.

MR. CARR: May it please the Commission, we do not intend at this time to present additional testimony but have Mr. Thompson here to answer whatever questions you may have.

MR. RAMEY: Are there any questions of Mr. Thompson?

MR. CHAVEZ: Yes, I have a few.

MR. RAMEY: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Thompson, would you please turn to Exhibit Fourteen of the -- of the previous case?

A All right. Okay.

Q Okay, during the year 1984 through '85 -- well, the year 1984, I guess, the hypothetical well in question on this exhibit would at that time, sometime in that year, qualify for stripper gas price, would it not?

A Yes, sir, it would.

Q Has that been taken into account in the prices in the --

A No, it has not.

Q Okay. I have done some calculations of own I should have made a copy of, but on the exhibit I just pencilled them in there. Does that, those prices seem reasonable to you as to what to expect for stripper gas prices during those years?

What I have done is in the year 1984 I just assumed that half the gross production would be at the 103 price and half would be at stripper price.

A Yes, they -- they look reasonable. I don't, you know, know exactly what it would be, but they appear to be reasonable to me.

Q Okay. In consideration of those prices I subtotaled the -- well, I got a new -- generated a new total for the total gas revenue of $2,118,000, which is an increase of $184,000 over the previous economics total of $1934, with an increase of $15,000 in taxes, to come up with a net income of $1,908,000, discounted at 9 percent to $688,000.

Do those figures seem reasonable to you?

A Yes, they look reasonable.

Q Okay. I did not go on to calculate the after tax rate of return because I did not know what tax rate you used and I didn't go into calculating them, but would you assume, then, that perhaps the -- a 9-1/2 percent increase in gross gas revenue might generate the same type of increase in after tax rate of return, say about 9 percent?

A. No, sir, I don't believe it would be that much. It would be somewhat higher but it wouldn't be that much.

Q. Okay, about how much? Would it be an 8 percent increase?

A. I think -- I'd have to calculate to be for sure, but I think perhaps it would increase to maybe 18 percent, or something like that.

Q. Okay, but what I meant was it would increase this by 9 or 8 percent.

A. Okay. All right. Okay.

Q. Thank you. Well, if it did go as high as 18 percent, then, wouldn't the amount of reserves necessary per well decline in order to reach the Southland limit of 15 percent rate of return after taxes?

A. Yes, it would be reduced slightly.

Q. Would you perhaps, if we left the record open, present to us a new exhibit showing a well with the cumulative reserves of 313,000, which I think was your calculated rate of reserves per well within the area, and showing the changes in the gas price to stripper gas price at the time at which the well would be eligible, and submit that with the rate of return that would be expected?

A. Yes, sir, I'd be happy to do that.

Q. Did you want to take a look at this a moment?

A. No, no, that's fine.

Q. Okay. Exhibit Fifteen that you presented at the hearing in the previous case in which you testified also does not include the stripper gas price but I don't -- I don't think I'll refer to that at this time.

How many multiple completions did Southland Royalty make within the area that they have requested to be designated as tight formation?

A. Very few in that area. Throughout the Basin we make a number of them but not in that particular area.

Q. Okay.

A. Most of the Mesaverde is already developed in the area, and the Pictured Cliffs is not that prospective, so we don't have that many prospects for dual completion.

Q. How many wells have been completed and produced in the Dakota formation, isn't it? It's in your last testimony. Which could be incorporated to the -- in your Exhibit Thirteen -- which, if you'll refer to that, was your listing of producing wells and estimated recoverable reserves?

A. I don't know of any. There may be a few that could be incorporated.

Q. I remember that there were two in I think it was Township 32, 12.

A. I'd be happy to check and update the map, if you'd like, but I don't know of any that haven't been made in the Dakota.

Q. Okay, there are two new wells, I know that for a fact, that weren't shown on the map that you presented in your first exhibit, and then incorporate the data from these wells in the same type of manner and present that, also, as an updated Exhibit Thirteen.

A. Okay, be happy to do that.

I've seen in doing this, I believe we have deleted five sections out of Township 32 North, 12 West, so any -- any wells in those five sections you would not want on the map, is that correct?

Q. That's right, any area that was deleted, I understand. In 32, 13, you've deleted Sections 30 and 31 because they were in the Barker --

A. Yes, yes, we deleted those, but the Commission deleted five sections, I believe, in 32, 12, and so we would not want to count any wells that were in those five sections, is that correct?

Q That's fine.

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

MR. RAMEY: Any other questions of the witness? Mr. Carr.

REDIRECT EXAMINATION

BY MR. CARR:

Q **Mr. Thompson, I believe that the December** 30, 1980, hearing you stated that Southland used a 15 percent rate of return, is that correct?

A That is correct.

Q Is that the total figure used by Southland?

A No, it is not. We're currently using 20 percent.

Q And why was this figure increased?

A Actually because of interest rates. At the time, interest rates went up at that time, almost a year ago, but we were still using the 15 percent, but because they have continued to stay up we have increased our minimum standard to 20 percent, and that's what we're using currently.

Q And that is used companywide?

A Yes, it is.

Q And what is the status of the drilling program in the subject area?

A. We're doing very little in the subject area. In fact, we're doing very little throughout the Basin now.

MR. CARR: I have no further questions.

MR. RAMEY: Any other questionsof the witness?

MR. CHAVEZ: Just one more. You used a discount rate of 9 percent. Has that changed?

A. We're currently using 15 percent, from 9 to 15. If we use those new numbers, you know, it's going to affect, you know, of course the price of a well now has gone up significantly since last year, too, so, you know, if we go ahead and use all the assumptions we made last year, everything is going to be out of date.

Perhaps it would be better to do a new economic run based on the current prices and current assumptions. Maybe that would be better for Exhibit Fourteen -- Exhibit Thirteen, whichever it is?

MR. CHAVEZ: That would be fine.

A. Okay.

MR. RAMEY: Any other questions? The witness may be excused.

Do you have anything further, Mr. Carr?

MR. CARR: Nothing further, Mr. Ramey.

MR. RAMEY: All right, we will hold open the record to enable you to update your Exhibit Thirteen and Exhibit Fourteen, is it?

MR. THOMPSON: Yes, sir.

MR. RAMEY: Is that correct? I won't put a deadline on it. It's to your advantage to get it in as soon as possible.

MR. THOMPSON: It will be in the near future.

MR. RAMEY: All right. We'll take the case under advisement.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

* REPORTER'S NOTE:

This hearing was recorded by Florene Davidson of the Commission's staff in the absence of the reporter. Thereafter, and using the tapes provided by her, the reporter transcribed the said hearing.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR
LARRY KEHOE
SECRETARY

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

January 13, 1982

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

Re: CASE NO. 7361
ORDER NO. R-6884

Applicant:

Southland Royalty Company

Dear Sir:

Enclosed herewith are two copies of the above-referenced Division order recently entered in the subject case.

Yours very truly,

Joe D. Ramey

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCD x
Artesia OCD x
Aztec OCD x

Other ______________________

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87501

Mr. Perry Pearce
Oil Conservation Division
New Mexico Department of
Energy & Minerals
Post Office Box 2088
Santa Fe, New Mexico 87501

CAMPBELL, BYRD & BLACK, P.A.
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WILLIAM F. CARR
BRADFORD C. BERGE
WILLIAM G. WARDLE

JEFFERSON PLACE
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TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

September 8, 1981

RECEIVED
SEP 08 1981
OIL CONSERVATION DIVISION
SANTA FE

Mr. Allen F. Buckingham
Supervisor
Determination Unit
United States Geological Survey
Post Office Box 26124
Albuquerque, New Mexico 87125

Re: Application of Southland Royalty Company for Designation of a Tight Formation, San Juan County, New Mexico

Dear Mr. Buckingham:

On December 30, 1980, the Oil Conservation Division heard Case 7116: the application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. At the time of the hearing, Consolidated Oil & Gas, Inc. appeared and requested that certain additional acreage be included within the designated tight formation. The examiner held that the legal advertisement of the hearing was broad enough to permit the consideration of Consolidated acreage. On August 7, 1981, the Division entered Order R-6747 granting Southland's application. This Order also recommended designation of certain Consolidated lands.

On August 21, 1981, Consolidated filed for a hearing de novo in this case. It is our understanding that the decision entered following the de novo hearing could be appealed further by Consolidated.

Southland Royalty Company has conferred with the Oil Conservation Division and representatives of Consolidated Oil & Gas, Inc. and it has been agreed that the Division will advertise Case 7116 for hearing de novo on September 29, 1981. At the time of the hearing, Southland will request that the Southland Royalty Company acreage included within this application be dismissed from the hearing. Consolidated will then proceed to present its case.

Enclosed is a copy of an Amended Application which Southland Royalty Company is filing on this date with the Oil Conservation Commission. As you will note, this application is confined to only Southland Royalty Company land. This application will also be set for hearing on September 29 at which time Southland will ask the Oil Conservation Commission to incorporate the Southland exhibits and testimony offered in Case 7116 on December 30, 1980. We do not anticipate at this time to offer new exhibits or testimony, although we will have representatives of Southland Royalty Company present should questions arise.

We are not, therefore, sending an additional set of exhibits to the United States Geological Survey as required by Oil Conservation Division rules. If you desire such exhibits or have any questions concerning this matter, please advise.

Very truly yours,

William F. Carr

WFC:lr

Enclosure

cc: Mr. Marlin Thompson
Ms. Lynn Teschendorf

bcc: Mr. Perry Pearce

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

COMMISSION HEARING

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I've seen in doing this, I believe we have deleted five sections out of Township 32 North, 12 West, so any -- any wells in those five sections you would not want on the map, is that correct?

Q. That's right, any area that was deleted, I understand. In 32, 13, you've deleted Sections 30 and 31 because they were in the Barker --

A. Yes, yes, we deleted those, but the Commission deleted five sections, I believe, in 32, 12, and so we would not want to count any wells that were in those five sections, is that correct?

Q That's fine.

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

MR. RAMEY: Any other questions of the witness? Mr. Carr.

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Thompson, I believe that the December 30, 1980, hearing you stated that Southland used a 15 percent rate of return, is that correct?

A That is correct.

Q Is that the total figure used by Southland?

A No, it is not. We're currently using 20 percent.

Q And why was this figure increased?

A Actually because of interest rates. At the time, interest rates went up at that time, almost a year ago, but we were still using the 15 percent, but because they have continued to stay up we have increased our minimum standard to 20 percent, and that's what we're using currently.

Q And that is used companywide?

A Yes, it is.

Q And what is the status of the drilling program in the subject area?

A We're doing very little in the subject area. In fact, we're doing very little throughout the Basin now.

MR. CARR: I have no further questions.

MR. RAMEY: Any other questionsof the witness?

MR. CHAVEZ: Just one more. You used a discount rate of 9 percent. Has that changed?

A We're currently using 15 percent, from 9 to 15. If we use those new numbers, you know, it's going to affect, you know, of course the price of a well now has gone up significantly since last year, too, so, you know, if we go ahead and use all the assumptions we made last year, everything is going to be out of date.

Perhaps it would be better to do a new economic run based on the current prices and current assumptions. Maybe that would be better for Exhibit Fourteen -- Exhibit Thirteen, whichever it is?

MR. CHAVEZ: That would be fine.

A Okay.

MR. RAMEY: Any other questions? The witness may be excused.

Do you have anything further, Mr. Carr?

MR. CARR: Nothing further, Mr. Ramey.

MR. RAMEY: All right, we will hold open the record to enable you to update your Exhibit Thirteen and Exhibit Fourteen, is it?

MR. THOMPSON: Yes, sir.

MR. RAMEY: Is that correct? I won't put a deadline on it. It's to your advantage to get it in as soon as possible.

MR. THOMPSON: It will be in the near future.

MR. RAMEY: All right. We'll take the case under advisement.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

* **REPORTER'S NOTE:**

This hearing was recorded by Florene Davidson of the Commission's staff in the absence of the reporter. Thereafter, and using the tapes provided by her, the reporter transcribed the said hearing.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION OF NEW MEXICO FOR THE PURPOSE OF CONSIDERING:

CASE NO. 7361
Order No. R-6884

APPLICATION OF SOUTHLAND ROYALTY COMPANY FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on September 29, 1981, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 12th day of January, 1982, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That, pursuant to Section 107 of the Natural Gas Policy Act of 1978, and CFR Section 271.703, applicant Southland Royalty Company requested the designation as a "tight formation" of the Dakota formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 33: All

containing a total of 92,871 acres, more or less.

(3) That at the hearing, applicant requested dismissal of that portion of the application pertaining to Sections 25 through 27, inclusive, and Sections 32 and 33, all in Township 32 North, Range 12 West, NMPM, containing some 3,200 acres, more or less, leaving for consideration some 89,671 acres, more or less.

(4) That said request for dismissal should be approved, and no further consideration given herein to said lands.

(5) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper limit of the Morrison formation.

(6) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(7) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," consists of a near blanket sandstone (probably an almost continuous series of northwest trending barrier beach sandstones composed of fine-grained quartose sandstones and carbonaceous shales with occasional conglomerates and coals in the basal part).

(8) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 5234 feet to 7220 feet and averages some 6753 feet beneath the surface.

(9) That the only test data for flow rates prior to stimulation for wells within the area indicates that the Aztec Pierce Well No. 2 in Section 30, Township 31 North, Range 10 West, NMPM, had a stabilized production rate calculated at atmospheric pressure of 208.1 MCF of gas per day; that other wells in the immediate vicinity of the area but just outside had stabilized production rates calculated at atmospheric pressure prior to stimulation ranging from 21.7 MCF per/day to 224.1 MCF per day.

(10) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6753 feet), and it is not expected that the average well in the area will exceed such rate.

(11) That in situ permeability calculations are available for only two wells in the general area, being the Southland Pierce Well No. 2 and the Southland Patterson "B" Com Well No. 1E; that the in situ permeabilities calculated for said wells are .0609 md and .0877 md, respectively, and average .0743 md.

(12) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(13) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(14) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(15) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(16) That Southland in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of

350,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 150,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(17) That the economics as presented by Southland in this case are reasonable, and lands which indicate recoverable reserves of 350,000 MCF or more of gas should be dismissed from further consideration, while lands indicating recoverable reserves of less than 350,000 MCF of gas should be considered for recommendation as a tight formation.

(18) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(19) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(20) That cumulative production figures and estimates of ultimate recoverable reserves were presented at the hearing for some of the developed tracts within the area, while cumulative production figures only are available for the remainder of the developed tracts.

(21) That to determine that under certain lands insufficient reserves are available to justify drilling absent the Section 107 incentive price, it is reasonable to make the following assumptions:

A. No primary drilling, i.e., no drilling on 320-acre spacing, is prima facie evidence that the lands are edge lands to the reservoir and drilling has not occurred because of the probable marginal nature of the reserves.

B. Primary drilling has occurred but the calculated total ultimate reserves or the cumulative production for long-connected wells indicates low ultimate recovery (less than 350,000 MCF of gas).

(22) That to determine that under certain lands sufficient reserves may reasonably be expected to be recovered to justify drilling without the Section 107 incentive price, it is reasonable to make the following assumptions:

A. Calculated ultimate recoverable reserves are 350,000 MCF or more.

B. Calculated ultimate recoverable reserves are not available, but cumulative recoveries indicate that 350,000 MCF of gas already has been recovered.

(23) That the assumptions in Findings Nos. (21) B. and (22) A. and B. above may reasonably be based on offsetting wells in a given area.

(24) That the evidence indicates that it is unreasonable to expect that wells drilled in the area described in Finding No. (2) above less the area described in Finding No. (3) above will yield an average of 350,000 MCF or more of gas, but that it is reasonable to expect that such wells will yield an average of 150,000 MCF of gas, and that the incentive Section 107 (c)(5) price is necessary to justify drilling in said area.

(25) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1200 feet.

(26) That there is a vertical distance of some 5500 feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply.

(27) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing some 89,671 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing approximately 89,671 acres, more or less.

(2) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

EMERY C. ARNOLD, Chairman

ALEX J. ARMIJO, Member

Joe D Ramey
JOE D. RAMEY, Member & Secretary

SEAL

I

GEOGRAPHICAL AND GEOLOGICAL DESCRIPTION

The recommended Dakota area is located in extreme north central San Juan County, New Mexico, adjacent to the Colorado state line and is in the northwestern portion of the San Juan Basin near the Hogback Monocline. The proposed area includes the following:

1.	T32N-R10W	All sections
2.	T32N-R11W	All sections except 28, 29, 30, 31, 32 and 33
3.	T32N-R12W	All sections except 34, 35 and 36
4.	T32N-R13W	All sections
5.	T31N-R10W	All sections
6.	T31N-R11W	Sections 1, 12, 13, 22, 23, 24, 25, 26, 27, 34, 35 and 36 only

This area is shown on Exhibit No. 1.

Exhibit No. 2 is a type log which shows the base of the Mancos, the Greenhorn, the Graneros and the Dakota formations. The vertical limits of the Baskin Dakota gas pool have been defined by the New Mexico Conservation Division to be from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation. The Graneros and first Dakota zones are the producing zones in the Basin Dakota Field. The other Dakota zones and the upper Morrison zone have very low permeability. Production from these zones has been limited to date.

The sediments of the Dakota interval were formed during late Cretaceous time. The Dakota is bounded by an uncomformable contact with the Jurassic Morrison below and is gradational with the Cretaceous Mancos shale above and is found at an average dept of 7050 feet. The gross thickness of the formation varies from 200 to 300 feet.

Deposition of the Dakota sediments occurred during a regression of the late Cretaceous sea. This regression resulted in the following sequence of depositional environments from the base upward: 1. Braided stream sandstone; 2. Meandering stream complex (with minor associated coals); 3. Coastal shale; 4. Coastal sandstone. The lower two environments contain sands of minor areal extent whereas the coastal sandstones have significant extent and are seen as northwest-southeast trending linear sand bodies reflecting their beach and off-shore bar depositional history. These upper Dakota sands appear to be the primary Dakota reservoirs.

The Dakota sands are light to dark mottled gray, fine to very fine-grained quartz sands. Silt and clay-sized matrix material can form a significant percentage of the bulk-rock composition. Because the matrix fraction tends to greatly reduce the effective permeability of the reservoir, natural and induced fractures are necessary for production from the Dakota reservoir.

Exhibit Nos. 3 and 4 are cross sections that show the continuity of the Dakota zones across the area of this application. Cross section A-A' shows sand development in a North-South direction while cross-section B-B' shows sand development in a northwest-southeast direction. The permeability of the zones in the area under consideration is lower than in more productive areas such as T31N-R12W. This is indicated by the poor performance of the wells in the proposed area compared to the wells located in T31N-R12W. This is shown by Exhibit No. 1, which is a completion and production map showing both 1979 annual oil and gas production and the cumulative oil and gas production as of January 1, 1980.

II

GEOLOGICAL AND ENGINEERING DATA

PERMEABILITY

Average in situ permeability for the Dakota formation is 0.1 md or less throughout the recommended area. Several methods were used to determine the average in situ permeability. Each method is described below, and the resulting value of permeability is provided.

1. Pressure Buildup Analysis. In order to determine in situ permeability by this method, it is necessary to produce the well prior to stimulation until it stabilizes then shut it in for a pressure build up with a pressure recorder at the bottom of the hole. This pressure data is then plotted against a time ratio and the slope of the straight line portion of the curve is determined. This slope is used to calculate permeability.

This method was used to determine an average in situ permeability of 0.0011 md in the Southland Royalty Company East No. 7E (See Exhibit No. 5).

2. Darcy's Law Analysis. In order to determine in situ permeability by this method, it is necessary to produce the well under pre-stimulation conditions until both the rate and flowing pressure stabilize. The well is then shut in and the stabilized shut-in pressure determined. With this and other known geological and engineering data, the permeability is calculated using the Darcy flow equation.

This method was used to determine in situ permeability values of 0.0877 and 0.0609 md in the Southland Royalty Company

Patterson "B" Com. No. 1E and Pierce No. 2, respectively (See Exhibit Nos. 6 and 7).

3. Core Analysis. Laboratory permeability is determined by employing coring equipment (bit and barrel) to cut and recover a portion of the reservoir rock. Small plugs are then cut from the rock at one-foot intervals, and the permeability is measured at laboratory conditions. Permeability at reservoir conditions is always less than it is at laboratory conditions because overburden pressure is greater than the pressure used in the laboratory. The higher pressure causes the permeability to be lower. The water that is present in the reservoir rock also causes the in situ permeability to be lower. A paper has been written that presents a method of determining the relationship between laboratory and in situ or reservoir permeability (See Exhibit No. 8).

This method was used to determine average in situ permeability values of 0.0335 and 0.0151 md in the El Paso Natural Gas Company Case No. 8 and Moore No. 8, respectively (See Exhibit Nos. 10 and 11). The laboratory permeabilities for the two wells are 0.1195 and 0.0538, respectively. This data is also shown on Exhibit Nos. 10 and 11. These two 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. The data from these summary tables was used in calculating the average permeability values. This method of determining in situ permeability is explained in Exhibit No. 9.

STABILIZED PRODUCTION RATES

Stabilized production rates were taken on three of the five test wells, the Southland Royalty Company East No. 7E, Patterson "B" Com. No. 1E and Pierce No. 2. The flow rates for

East No. 7E and Patterson "B" Com. No. 1E were taken before stimulation while the flow rate for Pierce No. 2 was taken after stimulation. The production rates were measured at pressures other than atmospheric. These rates were used to determine permeability. The production rates were then calculated at atmospheric conditions by employing the Darcy flow equation. The maximum gas production rate permitted under the tight formation guideline is 290 MCFD for the depth interval 7000-7500 feet. These three wells meet this guideline as shown on Exhibit No. 12. The other two wells, the El Paso Natural Gas Company Cas No. 8 and Moore No, 8, were dry holes and, therefore, did not produce.

OIL PRODUCTION RATES

The three productive test wells did not produce enough oil to measure during the production test. Daily oil production is, therefore, shown to be zero on Exhibit No. 12. None of the wells offsetting the three wells currently produce in excess of five barrels of oil per day as can be seen on Exhibit No. 1; therefore, the daily oil production limit is satisfied.

III

WELLS IN RECOMMENDED FORMATION

Exhibit No. 1 is a completion and production map which shows all of the wells that have produced from the Dakota formation in the geographical area of this application. The map also contains the 1979 annual gas and oil production and the cumulative gas and oil production as of January 1, 1980, as stated previously.

IV

PROTECTION OF FRESH WATER

Existing state and federal regulations will assure that development of the Dakota formation will not adversely affect or impair any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations occur in the area of interest. These are: 1. San Jose, 2. Nacimiento and 3. Ojo Alamo. The three formations occur from the surface of the ground to an average depth of 1200 feet.

In New Mexico, the Oil Conservation Division is responsible for protecting fresh water while drilling, completing and producing oil and gas wells as provided by Rule 106. This rule requires the casing to be designed to seal off water bearing formations thus separating them from oil and gas bearing formations. Additionally, federal regulations provide for protection of fresh water in oil and gas related activities.

The Dakota formation requires large fracture treatments during completion to provide favorable economics since it is a very tight formation. Fresh water protection is adequate even with these large stimulations. The top of the upper Dakota producing zone is approximately 5800 feet below the deepest fresh water zone thus providing additional insurance that no existing fresh water will be contaminated.

Together, state rules in 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 proposed tight sand area.

V

OTHER RELEVANT INFORMATION

RESERVES AND ECONOMICS

The average estimated ultimate gas recovery for each of the 31 wells in the area of interest that have produced is 313,614 MCF (See Exhibit No. 13). Fifteen of the wells are expected to have ultimate recoveries of less than 200,000 MCF. Gas reserves of 350,000 MCF are required to provide minimum standard economics of 15% rate of return after federal income tax at current 103 prices (See Exhibit No. 14) while gas reserves of only 150,000 MCF are required to provide minimum standard economics at 200% of current 103 prices (See Exhibit No. 15). As indicated, increased prices are necessary to justify drilling Dakota wells in the proposed area because the anticipated recovery is expected to be less than 350,000 MCF, thus causing the wells to be uneconomical at current prices.

Exhibit No. 16 is a tabulation showing the assumptions used in making the economic calculations. Exhibit No. 17 is an Authority for Expenditure showing the cost to drill and complete a Dakota well in the subject area.

MISCELLANEOUS INFORMATION

In addition to completion and production data, Exhibit No. 1 contains the following:

1. Location of cross sections A-A' and B-B'.
2. Location of test wells for which permeability, gas production and oil production rates are submitted.
3. Location of wells that were completed in the Dakota formation but never produced after the initial potential was taken.

4. Location of dry holes that have been drilled in the Dakota formation in the recommended area.

There are two wells in the proposed area that were completed in the Dakota formation but never produced after the initial potential was taken. There are five dry holes in the subject area that were drilled to test the Dakota formation. The failure to make successful Dakota completions in these seven wells provides additional indication that the Dakota formation exhibits very low permeability in the area under consideration.

Three of the test wells, Patterson "A" Com. No. 1E (SW-2-31N-12W), East No. 7E (SW-14-31N-12W) and Case No. 8 (NE-18-31N-11W), are not located in the proposed area. The wells are located near the area, however, where production is more prolific as shown by Exhibit No. 1. The fact that these wells meet the necessary guidelines even in a more productive area indicates that the proposed area will also meet the necessary guidelines.

VI

CONCLUSION

It has been shown in this recommendation that the Dakota formation in the proposed area meets the guidelines necessary to qualify the area for tight formation designation. These include the following:

1. The in situ permeability is less than 0.1 md.
2. The stabilized gas production rate (290 MCFD in the interval 7000-7500 feet) is less than the maximun that is permitted.
3. No well will produce more than five barrels of oil per day.

4. Any fresh water in the area will be adequately protected while the wells are being drilled, completed and produced.

In addition, it has been shown that Dakota wells drilled and completed in the area will not be economical at 103 prices. Added price incentive is, therefore, necessary before the gas reserves in the area can be developed and produced. If the incentive price is allowed to be received for the wells drilled in the recommended area, it is estimated that Southland Royalty Company will recover an additional 14 BCF of gas reserves that would not otherwise be available to existing gas markets.

RECEIVED
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OIL CONSERVATION DIVISION
SANTA FE

BEFORE THE

OIL CONSERVATION COMMISSION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF SOUTHLAND ROYALTY COMPANY,
FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO

Case 7361

APPLICATION

Comes now SOUTHLAND ROYALTY COMPANY, 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 County, New Mexico:

Township 31 North, Range 10 West, N.M.P.M.
    Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
    Section 1: All
    Sections 12 and 13: All
    Sections 22 through 27: All
    Sections 34 through 36: All

Township 32 North, Range 10 West, N.M.P.M.
    Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
Sections 7 through 27: All
Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 29: All
Sections 32 through 36: All

Containing a total of 92,871.00 acres, more or less.

2. The Dakota formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 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 the Oil Conservation Commission and that after notice and hearing as required by law, the Commission 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 lands be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By William F. Carr

William F. Carr
Post Office Box 2208
Santa Fe, New Mexico 87501
Attorneys for Applicant

RECEIVED
SEP 08 1981
OIL CONSERVATION DIVISION
SANTA FE

BEFORE THE
OIL CONSERVATION COMMISSION
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF SOUTHLAND ROYALTY COMPANY,
FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO

Case 7361

APPLICATION

Comes now SOUTHLAND ROYALTY COMPANY, 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 County, New Mexico:

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Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
Sections 7 through 27: All
Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 29: All
Sections 32 through 36: All

Containing a total of 92,871.00 acres, more or less.

2. The Dakota formation is expected to have an estimated average in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 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 the Oil Conservation Commission and that after notice and hearing as required by law, the Commission 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 lands be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By William F. Carr

William F. Carr
Post Office Box 2208
Santa Fe, New Mexico 87501
Attorneys for Applicant

[illegible]

T 31N R 12W

secs 5 thru 8
17 thru 20
29 thru 32 } 7442 acres

T 31N R 13W

secs 12 thru 14: 3
22 thru 28: 7
33 thru 36: 4
14

640
14
2560
640
8960

14 X 640 = 8960 acres

T 32N R 12 W

25 thru 27: 3
32 and 33: 2
5

640
5
3200

5 X 640 = 3200

7442
8960
3200
19,602

122,516
19,602
102914

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SEP 08 1981
OIL CONSERVATION DIVISION
SANTA FE

BEFORE THE

OIL CONSERVATION COMMISSION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION OF SOUTHLAND ROYALTY COMPANY, FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO

Case 7361

APPLICATION

Comes now SOUTHLAND ROYALTY COMPANY, 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 County, New Mexico:

Township 31 North, Range 10 West, N.M.P.M.
    Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
    Section 1: All
    Sections 12 and 13: All
    Sections 22 through 27: All
    Sections 34 through 36: All

Township 32 North, Range 10 West, N.M.P.M.
    Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
    Sections 7 through 27: All
    Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
    Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
    Sections 7 through 29: All
    Sections 32 through 36: All

Containing a total of 92,871.00 acres, more or less.

2. The Dakota formation is expected to have an estimated average *in situ* gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 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 the Oil Conservation Commission and that after notice and hearing as required by law, the Commission 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 lands be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL, BYRD & BLACK, P.A.

By William F. Carr
William F. Carr
Post Office Box 2208
Santa Fe, New Mexico 87501
Attorneys for Applicant

Docket No. 29-81

Dockets Nos. 31-81 and 32-81 are tentatively set for October 7, and October 21, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - WEDNESDAY - SEPTEMBER 23, 1981

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Richard L. Stamets, Examiner or Daniel S. Nutter, Alternate Examiner:

CASE 7353: Application of Texaco, Inc., for the amendment of Division Order No. R-5530, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of Order No. R-5530, which authorized its Central Vacuum Unit Area Pressure Maintenace Project, to increase the total project area allowable, or as an alternative, to reclassify the project as a waterflood project.

CASE 7354: Application of Corona Oil Company, for a pilot steam-enhanced oil recovery project, Guadalupe County, New Mexico. Applicant, in the above-styled cause, seeks authority to institute a pilot steam-enhanced oil recovery project in the Santa Rosa formation by using two existing wells and three additional wells to be drilled to complete a five spot pattern located in the NE/4 NW/4 of Section 17, Township 11 North, Range 26 East.

CASE 7355: Application of Doyle Hartman for directional drilling and an unorthodox location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to drill his Bates Well No. 3, 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, in such a manner as to bottom it at a depth of 3500 feet in the Jalmat Gas Pool at an unorthodox location 2310 feet from the South line and 1650 feet from the West line of Section 20. The SW/4 of said Section 20 would be dedicated to the well.

CASE 7356: Application of S & I Oil Company for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the W/2 SW/4 of Section 12, Township 29 North, Range 15 West, Cha Cha-Gallup Oil Pool, 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 7357: Application of Union Oil Company of California for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Atoka and Morrow formations underlying the W/2 of Section 16, Township 22 South, Range 33 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7343: (Continued from September 9, 1981, Examiner Hearing)

Application of Caribou Four Corners, Inc. for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Cha Cha Gallup Oil Pool underlying the E/2 NW/4 of Section 18, Township 29 North, Range 14 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 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 7358: Application of John Yuronka for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Langley Mattix Pool underlying the SW/4 of Section 6, Township 23 South, Range 37 East, to form four 40-acre tracts, each 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 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 7359: Application of Energy Reserves Group for creation of a new gas pool and an unorthodox location, Roosevelt County, New Mexico.

Applicant, in the above-styled cause, seeks creation of a new Cisco gas pool for its Miller Com Well No. 1, located in Unit M of Section 12, Township 6 South, Range 33 East.

Applicant further seeks approval of an unorthodox location for its Miller "A" Well No. 1-Y, to be drilled 1800 feet from the South line and 1700 feet from the East line of Section 11 of the same township. The S/2 of said Section 11 to be dedicated to the well.

CASE 7345: (Continued from September 9, 1981, Examiner Hearing)

Application of Bass Enterprises Production Company for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Lovington Penn Pool underlying the N/2 NE/4 of Section 13, Township 16 South, Range 36 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7360: Application of L. J. Buck for salt water disposal, Lea County, New Mexico. Applicant, in the above-styled cause seeks authority to dispose of produced salt water into the Seven Rivers formation in the interval from 3221 feet to 3250 feet in his Monco Well No. 2 in Unit M of Section 25, Township 25 South, Range 36 East.

CASE 7352: (Continued from September 9, 1981 Examiner Hearing)

Application of Yates Petroleum Corporation for designation of a tight formation, Eddy County, New Mexico. Applicant, in the above-styled cause, pursuant to Section 107 of the Natural Gas Policy Act 18-CFR Section 271.701-705, seeks the designation as a tight formation of the Permo-Penn and formation underlying all of the following townships:

Township 17 South, Ranges 24 thru
26 East;

18 South, 24 and 25 East;

19 South, 23 thru 25 East;

20 South, 21 thru 24 East;

20½ South, 21 and 22 East;

21 South, 21 and 22 East;

Also Sections 1 thru 12 in
22 South, 21 and 22 East,

All of the above containing a total of 315,000 acres more or less.

CASE 7329: (Readvertised)

Application of Loco Hills Water Disposal Company for an exception to Order No. R-3221, Eddy County, New Mexico

Applicant, in the above-styled cause, seeks an exception to Order No. R-3221 to permit the commercial disposal of produced brine into several unlined surface pits located in the N/2 SW/4 SW/4 of Section 16, Township 17 South, Range 30 East.

Dockets Nos. 31-81 and 32-81 are tentatively set for October 7, and October 21, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: COMMISSION HEARING - TUESDAY - SEPTEMBER 29, 1981

9 A.M. - OIL CONSERVATION DIVISION - MORGAN HALL
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

CASE 7116: (DE NOVO)

Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying portions of Township 31 and 32 North, Ranges 10, 11, 12, and 13 west, containing 93,860 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.

Upon application of Consolidated Oil & Gas, Inc., this case will be heard De Novo pursuant to the provisions of Rule 1220.

CASE 7361: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying all or portions of Township 31 North, Ranges 10 and 11 West, and Township 32 North, Ranges 10, 11, 12, and 13 West, containing 92,871 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 7362: Application of R. A. Mendenhall Associates, Ltd., for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Delaware Mountain Group formation underlying the NW/4 SE/4 of Section 10, Township 22 South, Range 27 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

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OIL CONSERVATION DIVISION

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
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TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

September 3, 1981

Case 7361

Mr. Joe D. Ramey, Director
Oil Conservation Division
New Mexico Department of Energy & Minerals
P.O. Box # 2088
Santa Fe, New Mexico 87501

Re: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

Dear Mr. Ramey:

Southland Royalty Company requests that a hearing be scheduled before the Oil Conservation Commission to consider its application to designate the following acreage within the Basin Dakota Field as a tight formation under Section 107 of the Natural Gas Policy Act of 1978:

Township 31 North, Range 10 West, N.M.P.M.
    Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
    Section 1: All
    Sections 12 and 13: All
    Sections 22 through 27: All
    Sections 34 through 36: All

Township 32 North, Range 10 West, N.M.P.M.
    Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
    Sections 7 through 27: All
    Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
    Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 29: All
Sections 32 through 36: All

Said area contains 92,871.00 acres, more or less.

Southland requests that this case be advertised for hearing before the full commission on September 29, 1981. A formal application will be filed with the commission at least ten days prior to the hearing date.

At the time of the de novo hearing in Case No. 7116, which is also scheduled for hearing on September 29, 1981, it is Southland's intention to ask that its acreage be dismissed from that application. This will permit Consolidated Oil & Gas, Inc. to seek a tight formation designation for other acreage in Townships 31 and 32 North, Ranges 10 through 13 West.

If you have any questions concerning this matter, please advise.

Very truly yours,

William F. Carr

William F. Carr

cc: Lynn Teschendorf, Attorney
Consolidated Oil & Gas, Inc.

HERBIE / DAN

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION OF NEW MEXICO FOR THE PURPOSE OF CONSIDERING:

CASE NO. 7361
Order No. R-6884

APPLICATION OF SOUTHLAND ROYALTY COMPANY FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

M.S.

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on September 29, 1981, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this ________ day of January, 1982, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That, pursuant to Section 107 of the Natural Gas Policy Act of 1978, and CFR Section 271.703, applicant Southland Royalty Company requested the designation as a "tight formation" of the Dakota formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM

Sections 7 through 33: All

containing a total of 92,871 acres, more or less.

(3) That at the hearing, applicant requested dismissal of that portion of the application pertaining to Sections 25 through 27, inclusive, and Sections 32 and 33, all in Township 32 North, Range 12 West, NMPM, containing some 3,200 acres, more or less, leaving for consideration some 89,671 acres, more or less.

(4) That said request for dismissal should be approved, and no further consideration given herein to said lands.

(5) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper limit of the Morrison formation.

(6) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing

interval throughout the area.

(7) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," consists of a near blanket sandstone (probably an almost continuous series of northwest trending barrier beach sandstones composed of fine-grained quartose sandstones and carbonaceous shales with occasional conglomerates and coals in the basal part).

(8) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 5234 feet to 7220 feet and averages some 6753 ~~6603~~ feet beneath the surface.

(9) That the only test data for flow rates prior to stimulation for wells within the area indicates that the Aztec Pierce Well No. 2 in Section 30, Township 31 North, Range 10 West, NMPM, had a stabilized production rate calculated at atmospheric pressure of 208.1 MCF of gas per day; that other wells in the immediate vicinity of the area but just outside had stabilized production rates calculated at atmospheric pressure prior to stimulation ranging from 21.7 MCF per/day to 224.1 MCF per day.

(10) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6753 ~~6603~~ feet), and it is not expected that the average well in the area will exceed such rate.

(11) That in situ permeability calculations are available

for only two wells in the general area, being the Southland Pierce Well No. 2 and the Southland Patterson "B" Com Well No. 1E; that the in situ permeabilities calculated for said wells are .0609 md and .0877 md, respectively, and average .0743 md.

(12) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(13) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(14) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(15) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(16) That Southland in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of 350,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 150,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(17) That the economics as presented by Southland in this case are reasonable, and lands which indicate AC ~~recoverable~~ AC ~~reserves of 350,000 MCF or more~~ of gas should be dismissed from further consideration, while lands indicating recoverable reserves of less than 350,000 MCF of gas should be considered for recommendation as a tight formation.

(18) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(19) That the remaining reserves under the 160-acre tract upon which the unit well is <u>not</u> located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(20) That cumulative production figures and estimates of ultimate recoverable reserves were presented at the hearing for some of the developed tracts within the area, while cumulative production figures only are available for the remainder of the developed tracts.

(21) That to determine that under certain lands insufficient reserves are available to justify drilling absent the Section 107 incentive price, it is reasonable to make the following assumptions:

A. No primary drilling, i.e., no drilling on 320-acre spacing, is prima facie evidence that the lands are edge lands to the reservoir and drilling has not occurred because of the probable marginal nature of the reserves. ✓?

B. Primary drilling has occurred but the calculated total ultimate reserves or the cumulative production for long-connected wells indicates low ultimate recovery (less than 350,000 MCF of gas).

(22) That to determine that under certain lands sufficient reserves may reasonably be expected to be recovered to justify drilling without the Section 107 incentive price, it is reasonable to make the following assumptions:

A. Calculated ultimate recoverable reserves are 350,000 MCF or more.

B. Calculated ultimate recoverable reserves are not available, but cumulative recoveries indicate that 350,000 MCF of gas already has been recovered.

(23) That the assumptions in Findings Nos. (21) B. and (22) A. and B. above may reasonably be based on offsetting wells

in a given area.

(24) That the evidence indicates that it is unreasonable to expect that wells drilled in the area described in Finding No. (2) above less the area described in Finding No. (3) above will yield an average of 350,000 MCF or more of gas, but that it is reasonable to expect that such wells will yield an average of 150,000 MCF of gas, and that the incentive Section 107 (c)(5) price is necessary to justify drilling in said area.

(25) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1200 feet.

(26) That there is a vertical distance of some 5500 ~~5400~~ feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply.

(27) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM

Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM

Section 1: All

Sections 12 and 13: All

Sections 22 through 27: All

Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM

Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM

Sections 7 through 27: All

Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM

Sections 7 through 24: All

Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM

Sections 7 through 29: All

Sections 32 through 36: All

containing some 89,671 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said

formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM

Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM

Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM

Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM

Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM

Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM

Sections 7 through 29: All
Sections 32 through 36: All

containing approximately 89,671 acres, more or less.

(2) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

EMERY C. ARNOLD, Chairman

ALEX J. ARMIJO, Member

JOE D. RAMEY, Member & Secretary

SEAL