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

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

OIL CONSERVATION DIVISION
BOX 2088
SANTA FE, NEW MEXICO 87501

DATE Jan 24, 1984

RE: Proposed MC _____
Proposed DHC ✓
Proposed NSL _____
Proposed SWD _____
Proposed WFX _____
Proposed PMX _____

Gentlemen:

I have examined the application dated Jan 23, 1984

for the Jerome P. McHugh Native Son #2 N-27-25N-2W
Operator Lease and Well No. Unit, S-T-R

and my recommendations are as follows:

This well does not qualify for administrative approval. Case # 8041 has been docketed and continued pending the result of this application. Notify applicant to proceed with hearing.

Yours truly,

Frank T. Chavez

dugan production corp.

January 18, 1984

Joe Ramey, Director
New Mexico Oil Conservation Division
P O Box 2088
Santa Fe, NM 87501

RE: Request for Administrative Approval to Commingle
Jerome P. McHugh - Native Son No. 2
Basin Dakota and Gavilan Mancos Pools
Unit N Sec. 27 T25N R2W, N.M.P.M.
Rio Arriba County, NM

Dear Mr. Ramey:

We are writing on behalf of Jerome P. McHugh and Associates to request administrative approval to commingle production within the well bore of the Native Son No. 2, from perforations within the Basin Dakota and the Gavilan Mancos pools.

The subject well was completed on November 18, 1983, testing 58 BOPD and 34 BWPD (load) plus 223 MCFGPD from perforations in the Dakota formation, 7886-7977', and 233 BOPD, 34 BWPD (load) plus 440 MCFGPD from perforations in the Mancos, 6802-7485'. The initial potential test indicates this to be among the better wells in the field to date. We have attached Table No. 1 for your information, which is a summary of wells completed to date within the boundry of the Gavilan Mancos oil pool.

The Native Son No. 2 was spudded on October 8, 1983, and 4½" casing was cemented at 8133'. The Dakota formation was perforated with a total of 21 holes throughout a 91' gross interval to develop 7 separate intervals and a total net pay of 15', with an overall average porosity of 6.7%. Within this 15 feet of net pay it is believed that 4' (averaging 8.25% porosity) will contribute a majority of the productivity and that 11' (average porosity 6.1%) will not significantly contribute to productivity in view of the shaliness and/or the fact that individual beds are so thin that lateral continuity from the well bore is very unlikely. The Mancos formation was perforated 6802-7485', an overall interval of 683', to develop 33 separate intervals with an estimated net pay of 58' and an average porosity of 14.0%. Within this 58' of pay, 25', with an average porosity of 12.6%, is believed to have reservoir characteristcs that will permit a significant contribution to productivity and 33' of pay, with an average porosity of 15.1%, is either

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too shaly or is of such thin beds that even though some productivity is expected, the contribution of this pay will not be a significant factor in total productivity. I have summarized in Table No. 2 my evaluation of the open hole logs which resulted in the above reservoir parameters. The water saturation was not calculated because it is my belief that all intervals within the Mancos and Dakota formations are not thick enough to allow the induction electric log to read true resistivity and we do not have the necessary data to make thin bed corrections on the resistivity measurements in order to approximate the true formation resistivity. In addition, the shale content of the Mancos formation also has a significant effect on the resistivity log and even though we could make a correction for shale content, I consider it to be a futile effort in view of the thinness of a majority of the beds.

With reference to Table No. 2, and the log section presented as Figures No. 3 and 4, it can be seen that during our drilling operations large amounts of mud were lost while drilling the Mancos interval and we believe this to be an indication of natural fracturing within the Mancos and is the explanation for the better than average initial potential in the Native Son No. 2. We encountered more lost circulation in the Native Son No. 2 than in any other well we have drilled to date. We have attached a copy of our daily report during the drilling and completion operations of this well for your review.

The Native Son No. 2 is located in Unit N of Section 27 and the production unit for the Dakota and Mancos formations comprises the S/2 of Section 27. With reference to Figure No. 1, ownership of offsetting leases is indicated. As a matter of interest, McHugh and Dugan Production Corp. jointly have interest in a majority of the adjoining leases totaling 775 net acres of the 1600 acres immediately adjacent to the production unit for the Native Son No. 2. With reference to Figure No. 2, we have indicated the Mancos (Gallup) and Dakota wells in the general area of the Gavilan Mancos pool and have identified those wells currently authorized to commingle Mancos and Dakota downhole as well as existing pools that permit commingling of Gallup and Dakota within the well bore. These pools are the West Lindrith Gallup-Dakota approximately 8½ miles to the west and the Ojito Gallup-Dakota approximately 8 miles to the northwest. It should be noted that the two wells located in the N/2 of Section 26, T-25 N, R-2 W, (the Gavilan No. 1 & No. 1E) are indicated on the map to be completed in the Mancos and Dakota and not commingled; however, the operator, Northwest Exploration Company, is requesting permission to commingle production from the Mancos and Dakota within the well bore (NMOCD Case No. 8042). Commingling of the Mancos and Dakota in this general area is an accepted practice in 5 of the wells in the immediate vicinity and, as mentioned, is proposed for 2 additional wells. Should the 2 wells in the N/2 of Section 26 be authorized to commingle Mancos and Dakota production, all wells currently completed in the Mancos and Dakota within the Gavilan Mancos pool area will be authorized to commingle production downhole. Our request to commingle the Mancos and Dakota in the Native Son No. 2 is mainly to permit production to occur from the Dakota formation, which will not support the economic burden of a dual completion attempt.

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With reference to Figures No. 3 and No. 4, which are reproductions of the open hole log for the Native Son No. 2 through the Mancos and Dakota intervals, we have indicated the perforations in both horizons and it is our belief that all potentially productive pay has been perforated and stimulated. In addition, the intervals of lost circulation within the Mancos are indicated.

The production performance of the Gavilan No. 1, operated by Northwest Exploration approximately 1.7 miles to the northeast, is presented on Figure No. 5. As of December 1, the Gavilan No. 1 had produced 21 months and cummulative production amounted to 22,162 BO plus 180.8 MMCF of gas. The production data plotted on Figure No. 5 represents production from the Mancos only through July, 1983, and commingled Gallup-Dakota production during August, September and part of October, with only the Dakota being produced during the latter part of October and during November. On Figure No. 5 we have also indicated our anticipated production performance for the Native Son No. 2, beginning in January, 1984, at a rate of approximately 3700 BO per month, which represents a sustained production rate equal to 42% of the combined initial potential of 291 BOPD. We would expect production to decline at an annual rate of 40% for 3½ years and then stabilize at a 9% annual decline. This production forecast was developed by averaging production data from 4 wells in the West Lindrith Gallup-Dakota and 2 wells in the Ojito Gallup-Dakota fields. A similar production projection was utilized on the 5 wells previously authorized to commingle production from the Mancos and Dakota and the data supporting this projection is presented on Figure No. 6. As can be seen from production performance of the Gavilan No. 1, it is very difficult to make any projections as to how future production should perform; however, it can be seen that our projection for the Native Son No. 2 is not an unrealistic forecast considering that a majority of the performance from the Gavilan No. 1 occurred with very little influence from offset wells. None of the 5 wells operated by McHugh had any significant production until May, 1983. The Gavilan No. 1E, located in the NW of Section 26, did not start producing until August, 1983, and is averaging 51 BOPD. The Rucker Lake No. 2 and No. 3, located to the NE and SE respectively, commenced producing in September and August, averaging approximately 100 BOPD per well. We would expect performance of the Gavilan No. 1 to begin a decline in the near future. As you are aware, this is an area of fairly recent development and very little is known about the reservoir to date.

Utilizing the production projection presented in Figure No. 5, it is estimated that ultimate recovery from the Native Son No. 2 will be 147,400 BO. The ultimate recovery is split between the Dakota and Mancos utilizing a volumetric calculation for the ultimate recovery in the Dakota. It is estimated that the Dakota reserves will be 19,500 STB, which will result in 127,900 BO being produced from the Mancos interval. Utilizing these reserve figures along with an estimate of an overall GOR of 10,200 and 3,500 for the Mancos and Dakota respectively, gas reserves are estimated to be 1,304.6 MMCF for the Mancos and 68.2 MMCF for the Dakota. Utilizing these reserve estimates, ultimate recoveries will be split between the Mancos and Dakota as follows:

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	Mancos	Dakota
Oil	87%	13%
Gas	95%	5%

The details in support of these reserve calculations and allocation factor calculations are presented in Table No. 3. For your reference, the allocation factors for the 5 wells operated by McHugh and previously authorized to commingle production downhole are summarized on Table No. 4 along with the proposed factors for the Native Son No. 2.

The Mancos and Dakota Formations are each productive of hydrocarbons that are compatible with each other and it is our belief that any water associated with each zone is also compatible and that there will be no damage to either zone as a result of this commingling. Both formations were stimulated utilizing a water based fluid. Cross flow of fluid between each zone is not anticipated to be a serious problem. The BHP in the Mancos at a datum of 7144' (mid perf) is estimated to be 1,690 psig and the BHP in the Dakota at a datum of 7932' (mid perf) is estimated to be 2,674 psig. These pressures were determined from pressure build-up data in each zone in the Gavilan No. 1, located in the NE of Section 26, and are believed to be representative of each formation.

In summary, we are requesting permission to commingle production from the Mancos and Dakota formations within the well bore of the Native Son No. 2. To date very little production has actually occurred from this well, as it will not flow up the tubing; however, it will flow up the casing-tubing annulus. It is our plan to install artificial lift equipment in the well in order to produce the Native Son No. 2 since flowing the well up the casing-tubing annulus is not a practical option in view of the fact that both formations have a tendency to deposit paraffin. It is our belief that production from the Dakota will be a fairly minor part of the productivity and should this commingling not be permitted, the economics of dually producing both zones will likely prohibit producing the Dakota and an additional well to produce the Dakota only cannot be justified. Therefore, in order to allow the working interest owners in the S/2 of Section 27 to benefit from what productivity exists in the Dakota and to protect their correlative rights as the Dakota is being produced in other wells in the area, it is requested that the NMOCD authorize this commingling. Any revenue generated as a result of production from the Dakota will be in addition to revenues that will be generated from producing the Mancos only and therefore this commingling will result in an increase in ultimate hydrocarbon recoveries and revenue from this well.

The ownership of both horizons is common. The offset operators indicated on Figure No. 1 have been notified in writing of this application and by copy of this application we are notifying the Bureau of Land Management, since this well is located on Federal Lease No. 23038.

January 18, 1984

Should you have any questions regarding our application or need additional information, please do not hesitate to contact me.

Sincerely,

John D. Roe

John D. Roe
Petroleum Engineer

fp

cc: NMOCD, Aztec
Jerome P. McHugh, DE & Fmn
BLM, Fmn

dugan production corp.

JEROME P. McHUGH
Native Son #2
1020 FSL - 1670' FWL
Sec. 27, T25N R2W NMPM
Rio Arriba County, NM

MORNING REPORT

10-9-83 230' W.O.C.
Spudded 12-1/4" hole at 6:30 p.m. 10-8-83. Drilled to 230'. Rigged up and ran 5 jts. 9-5/8" O.D., 47#, 8 Rd, LT&C casing. T.E. 212.18' set at 224' RKB. Cemented with 135 sx class B plus 2% CaCl. P.O.B. at 5:15 a.m. 10-9-83. Circulated good cement to surface. W.O.C.

10-10-83 1654' Drilling Wt. 8.9 Vis 29 W.L. 10.0 1° at 512'; 1½° at 790'; 1-3/4° at 1035'; 2° at 1256'; 2¼° at 1550'

1 hr. - trip
12-1/4 hrs - drilling
1-3/4 hrs - survey
8-1/4 hrs - W.O.C.
3/4 hr. - drilling cement

Pressure tested surface casing and B.O.P. to 1000 psi for 30 min. Held OK.

10-11-83 3003' Drilling Wt. 8.8 Vis 27 W.L. 7.0 2-1/2° @ 1810' 2-3/4° @ 2026'; 3° @ 2235'; 3° @ 2450'; 3°@ 2708'; 2°@ 2963'

1-1/2 hrs - trip
19-1/2 hrs - drilling
1/2 hr - rig service
2-1/2 hrs - surveys

10-12-83 3698' - Drilling Wt. 9.0 Vis 38 W.L. 9.0 2° at 3078' 2° at 3213'; 1-3/4° at 3430'; 2° at 3651'

2-3/4 hrs - trip
18-1/4 hrs - drilling
1/2 hr - rig service
2 hrs - surveys
1/2 hr - wash 60' to bottom

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10-13-83 3976' - Drilling Wt. 9.0 Vis 45 W.L. 8 10% LCM
2° at 3893'

4-1/2 hrs - trip
8-1/4 hrs - drilling
1/2 hr - rig service
1/4 hr - survey
7-1/2 hrs - pull 15 stands, mix mud and trip back in hole
3 hrs - working pipe and regaining circ. Lost circ. during trip.

10-14-83 4364' - Drilling Wt. 9.0 Vis 42 W.L. 8.0 Trace LCM
3/4° at 4156'

3-3/4 hrs - trip
19-1/4 hrs - drilling
3/4 hr - rig service
1/4 hr - survey

10-15-83 4890' - Drilling Wt. 9.0 Vis 37 W.L. 12 1° at 4444'

3-1/2 hrs - trip
19-3/4 hrs - drilling
1/2 hr - rig service
1/4 hr - survey

10-16-83 5182' - Waiting on Magnet Wt. 8.7 Vis 42 W.L. 10.5
20% LCM 1° at 4948'

2-1/2 hrs - trip
12-1/2 hrs - drilling
1/4 hr - rig service
3/4 hr - survey
1-3/4 hrs - W.O. magnet
6-1/4 hrs - lost circ. at 5182 (lost 500 bbls.)

10-17-83 5182' - Fishing Wt. 8.7 Vis 42 W.L. 10.5 20% LCM

16-1/4 hrs - trip
1 hr - W.O. magnet
1 hr - wash to bottom
1-1/4 hrs - rig repair
3-3/4 hrs - mixing mud
1/2 hr - trying to unplug magnet - lost 650 bbls. mud
1/4 hr - rig service

10-18-83 5225' - drilling Wt. 8.8 Vis 42 W.L. 14 14% L.C.M.

17-1/4 hrs - trips
2-1/4 hrs - drilling
1/2 hrs - circ. and cond. mud
4 hrs - rig repair

10-19-83 5669' - Drilling Wt. 8.7 Vis 45 W.L. 10 8% LCM
1½° at 5528'

5-3/4 hrs - trip
16-1/2 hrs - drilling
1/4 hr - rig service
3/4 hr - rig repairs
3/4 hr - cut drilling line

10-20-83 6191' - Drilling Wt. 8.8 Vis 48 W.L. 100 4% LCM
1¼° at 6065'

22-3/4 hrs - drilling
3/4 hr - rig service
1/2 hr - survey

10-21-83 6643' - Trip Wt. 9.0 Vis 45 W.L. 11 5% LCM

2 hrs - trip
19 hrs - drilling
3/4 hr - rig service
1/4 hr - survey
2 hrs - mix mud and LCM (lost 200 bbl. mud 6073-6222 & 125 bbl. mud 6556-6611)

10-22-83 6868' - mixing mud & LCM Wt. 8.9 Vis 48 W.L. 10.0
6% LCM

6-1/2 hrs - trip
15-3/4 hrs - drilling
3/4 hr - rig service
1 hr - mix mud and LCM (Lost 400 bbls. mud at 6868')

10-23-83 7019' - Drilling Wt. 8.7 Vis 48 W.L. 7.0 30% LCM

3-3/4 hrs - trip
6-1/2 hrs - drilling
1/4 hr - rig service
13-1/2 hrs - mix mud & LCM - filling hole and regaining circ. Lost 450 bbl. mud at 6981'. Pulled 10 stands and pumped mud in hole with no returns. Pulled 10 more stands and hole unloaded. Flowed gas and mud in

(Cont.)

10-23-83 (cont.) heads. No oil. Pumped mud in hole and killed gas flow. Pulled pipe to 3399' and mixed and pumped mud. Regained circulation. Pumped approx. 700 bbl. mud attempting to regain circulation. Lost additional 200 bbls. after regaining circ.

10-24-83 7314' - Drilling Wt. 8.7 Vis 42 W.L. 10.0 10% LCM
2½° at 7175'

23-1/4 hrs - drilling
1/4 hr - rig service
1/2 hr - survey

10-25-83 7335' - Mixing mud Wt. 8.7 Vix 44 Wt. 10 10-12% LCM

11-3/4 hrs - trip
3-1/4 hrs - drilling
1/2 hr - rig service
4 hrs - rig repair
4-1/2 hrs - mix salt gel squeeze.

10-26-83 7335' - Mixing mud Wt. 8.8 Vis 50 W.L. 10 20% LCM

4-1/2 hrs - trips
1/2 hr - rig service
13 hrs - washing bridges
4-1/2 hrs - mixing mud
1-1/2 hrs - repairs

10-27-83 7335' - 24 hrs. lost circulation. Set one salt gel plug at 3900' Now trip in hole at 7000' washing to bottom. Have full returns at report time.

10-28-83 7447' - Washing to bottom

3-1/4 hrs - trip
7-1/2 hrs - drilling
3 hrs - wash to bottom
8 hrs - mix mud
2-1/4 hrs - spot salt gel squeeze

10-29-83 7740' - Drilling Wt. 8.9 Vis 45 W.L. 12.0 20% L.C.M.
2° at 7685'

1/4 hr - trip
21-1/4 hrs - drilling
1/2 hr - rig service
3/4 hr - survey
1-1/4 hrs - wash 140' to bottom

10-30-83 7882' - Trip Wt. 8.9 Vis 43 W.L. 11.0 18% LCM

7-1/2 hrs - trip
14 hrs - drilling
1 hr - rig service
3/4 hr - cut drilling line
3/4 hr - repair

10-31-83 8035' - Drilling Wt. 8.9 Vis 45 W.L. 12.0 20% L.C.M.

7-3/4 hrs - trip
14 hrs - drilling
1 hr - rig service
1-1/4 hrs - wash to bottom

11-1-83 T.D. 8128' - Logging Wt. 9.0 Vis 60 W.L. 12 20% L.C.M.
1½° at 8128'

5 hrs - trip
6-3/4 hrs - drilling
1/4 hr - rig service
2 hrs - circ.
2 hrs - change drilling line
8 hrs - logging

11-2-83 T.D. 8128' - Running 4½" casing
Finished running IES, CDL & CNL logs by Welex. T.I.H. with drill pipe. Circ. bottoms up. Laid down drill pipe and rigged up to run 4½" casing. Now running 4½" casing.

11-3-83 Ran 208 jts. 4½" OD, 11.6#, K-55, 8 Rd LT&C csg. T.E. 8154.28' - cemented - set @ 8133' RKB. Cemented first stage with 10 bbls. mud flush followed by 400 sks 50-50 pos with 2% gel and 6¼# gilsonite per sk and ¼# flocele per sack, followed by 150 sks class "B" neat with ¼# flocele per sk. (Total cement slurry first stage - 737 cu. ft.) Good circulation throughout job. Maximum cementing pressure 800 psi. Reciprocated csg. OK while cementing. Bumped plug with 1500 psi. Float held OK. Dropped opening bomb. Opened stage tool at 5852'. Circulated with rig pump 2½ hrs. Rigged up HOWCO and cemented 2nd stage with 10 bbls. mud flush, followed by 210 sks 65-35 with 12% gel - 6¼# gilsonite per sk. and ¼# flocele per sk., followed by 310 sks 50-50 pos with 2% gel and ¼# flocele per sk. (Total cement slurry 2nd stage - 885 cu. ft.) Good circulation throughout job. Maximum cementing pressure 800 psi. Closed stage tool with 2500 psi. Held OK. Dropped opening bomb and opened stage tool at 3570'. Circulated with rig pump 1½ hrs. Rigged up HOWCO and cemented 3rd stage with 10 bbls. mud flush, followed by 450 sks 65-35 plus 12% gel and ¼# flocele per sk, followed by 100 sks 50-50 pos with 2% gel and ¼# flocele per sack. (Total cement slurry 3rd stage - 1121 cu. ft.) Maximum cementing pressure 800 psi. Closed stage tool with 2500 psi. Held OK. Circulated

11-3-83 (Cont.) mud flush with tr. contaminated cement. Job complete 3:00 P.M. 11-2-83. Nippled down BOP. Set 4½" csg slips. Cut off csg. and released rig at 5:00 P.M. 11-2-83.

DAILY REPORT

11-4-83 Move in and rig up Pioneer Well Service. Nipple down well head. Nipple up BOP. Set pump and pit. Shut well in. Tubing did not show up.

11-5-83 Unload tubing truck. Run in hole with 3-7/8" bit and tubing. Tag up at 3570'. Drilling 10' cement. Drilling D.V. tool. Circulate clean. Drain pump. Shut down for night.

11-6-83 Sunday - shut down

11-7-83 GIH with tbg. Tag up @ 5700'. Drlg cement and DV tool @ ± 5852'. Circulate clean. GIH with tbg. Tag up @ 7980'. Clean out LCM to ± 8019'. Circulate clean. Rig up Western Co. Press test 4½" casing to 4000 psi - OK. Spot 250 gallons 7½% double inhibited HCL. P.O.H. Rig up Basin Perforators and attempt to record GR correlation log. Panel out of truck. Shut down.

11-8-83 Change out perforating trucks. Ran GR-Correlation log from PBTD 8044' to 7700', 7500 to 7300', 7100 to 6700', 5820 to 5150', 3550 to 3300', 3050 to 2550'.

Perforate Lower Mancos 7326, 94; 7436, 66, 75, 78, 85 (7 holes).

Perforate Dakota 7886, 88; 7919, 30, 38, 55, 63, 65, 67, 68, 69, 75, 76, 77 (14 holes).

Breakdown perfs with water at 2100 psi. ISDP 1300 psi. Drop 31 RCN ball sealers. Did not ball off. Reached 3900 psi at 5 BPM. Ran 4½" junk basket. Retrieved 29 balls (15 hits).

Fraced Lower Mancos (7326-7485) and Dakota (7886-7977) perfs as follows:

15,000 gal. Mini-Max III-30 with 2% diesel - pad
15,000 gal. Mini-Max III-30 with 2% diesel + 1 ppg 20/40 sand
15,000 gal. Mini-Max III-30 with 2% diesel + 1½ ppg 20/40 sand
15,000 gal. Mini-Max III-30 with 2% diesel + 2 ppg 20/40 sand
4,746 gal. fresh water flush

Max. treating press. 3800 psi Min. treating press. 3200 psi
Ave. treating press. 3400 psi at 27 BPM
ISDP 2300 psi 15 min. shut in 2300 psi

Totals: 60,000 gal. Mini-Max III-30, 67,500# 20-40 sand, 1200 gal. Aqua Flow, 55# B-5 breaker.

Could not get 4½" retrievable bridge plug through upper D.V. tool. Shut down.

11-9-83 Opened well up. Flowing back water. GIH with casing scraper and bit. Ream out DV tools at 3570 and 5852'. POH. Rig up Basin Perforators. Set retrievable bridge plug at 7250'. Dump 1 sack of sand on top of bridge plug. Pressure test to 4000 psi. Held OK.

Perforate Mancos as follows: 6802, 16, 36, 44, 49, 53, 69, 71, 73, 75, 81, 98; 6900, 02, 04, 13, 27, 29, 31, 39, 41, 53, 65, 77, 83, 88, 91; 7023, 29, 33, 36, 39, 49, 53, 61, 66, 70, 73, 80, 87. (Total 40 holes, 6802-7087)

Start breakdown - est. rate 50 BPM at 3800 psi. Drop 60 RCN ball sealers. Ball off with 4000 psi. Ran 4½" junk basket. Retrieved 14 balls (9 hits).

Fraced Mancos as follows:

15,000 gal. gelled water pad with 25# Aqua Seal/1000 gal.
20,000 gal. gelled water with 15# Aqua Seal/1000 gal. + 1 ppg 20/40 sand
12,000 gal. gelled water with 10# Aqua Seal/1000 gal. + 1½ ppg 20/40 sand
12,000 gal. gelled water with 10# Aqua Seal/1000 gal. + 2 ppg 20/40 sand
11,000 gal. gelled water with 10# Aqua Seal/1000 gal. + 2½ ppg 20/40 sand
4,410 gal. gelled water flush

ISDP 400 psi Well went on vacuum in 3 min.
Max. treating press. 3650 psi. Min. treating press. 2900 psi.
Ave. treating press 3100 psi at 58 BPM.

Totals: 70,000 gal. gelled water (20# J-2/1000 gal.), 89, 500 # 20/40 sand, 1200# Aqua Seal, 70 gal. Aqua Flow, 70# B-5 breaker, 1400# J-2 gel

Shut well in for night.

11-10-83 Well on vaccum. T.I.H. with retrieving head to 5000'. Ran in with swab to check fluid level - 3000'. T.I.H. with tbg to 7028' - Tag sand. Unable to establish circulation. P.O.H. Shut down.

11-11-83 GIH with retrieving head and Depek tubing bailer. Tag sand at 7028'. Clean out to bridge plug and latch onto bridge plug. P.O.H. Lay down bridge plug. G.I.H. with Depek tubing bailer. Tag sand at 7967'. Clean out to 7987'. Bailer quit working. P.O.H. Shut in for night.

11-12-83 Csg. 350 psi. Blew well down. Went in hole with tubing, seating nipple, tubing anchor. Land tubing as follows: 244 jts. 2-3/8" O.D., 4.7#, J-55, 8 Rd, EUE tubing. T.E. 7862.31' set at 7870' RKB with seating nipple at 7838' and tubing anchor at 6554' with 14000# tension. Nipple down BOP. Nipple up well head. Shut in. Rig down Pioneer Well Service.

11-13-83 Shut down.

11-14-83 Moved in and rigged up Basin Service swabbing unit. Casing pressure 515 psi. Tubing pressure 460 psi. Opened well. Did not unload. Swabbed 2-3/8" tubing. Fluid level first run 2800'. Made 18 swab runs. Swabbed estimated 150 bbls. frac water. No show of oil; good show of gas. Casing pressure at end of day 900 psi.

11-15-83 Casing pressure 975 psi. Tubing pressure 350 psi. Blew well down. Made 22 swab runs. Fluid level on first run 3200'. Swabbed estimated 175 bbls. frac fluid. Fluid level at end of day 4000'. Casing pressure 1450 psi. No show oil; slight show gas. S.D.O.N.

11-16-83 Casing pressure 1450 psi. Tubing pressure 450 psi. Well did not unload. Fluid level first run 3400'. Made 20 swab runs and swabbed estimated 160 bbls. frac fluid. Fluid level remained at 3400' all day. Very slight show oil last 5 runs of day. Casing pressure at end of day 1460 psi. Good gas show after 10 runs. S.D.O.N.

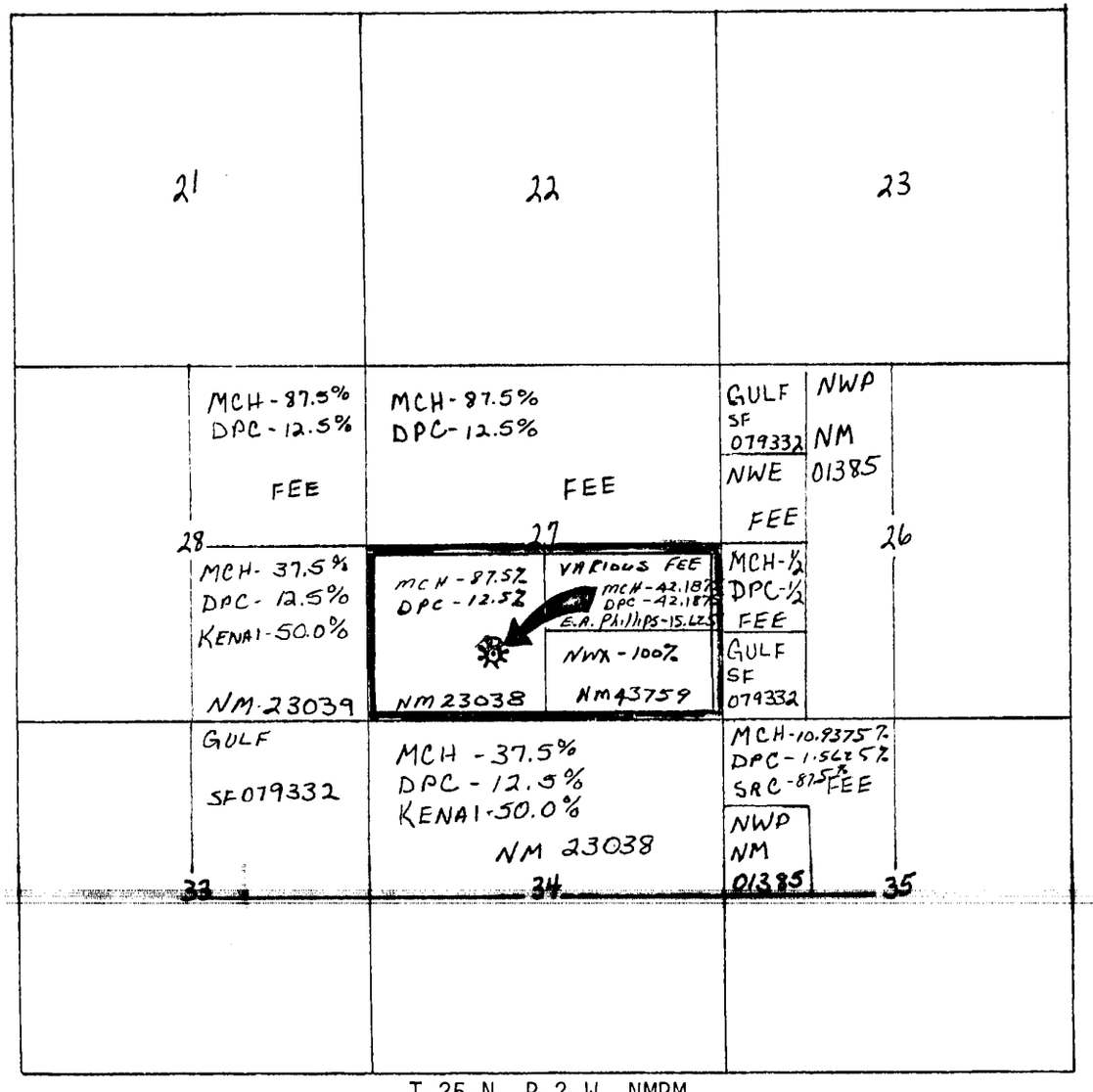
11-17-83 Casing pressure 1400 psi. Well did not unload. Made two swab runs to pit. Recovered 5 bbls. oil. Fluid level at 3400' first run. Made 15 runs to pit.- all frac fluid - estimated 120 bbls. Well kicked off at 3:00 p.m. Flowed well to tank making undetermined amount of oil. Flowed 95 bbls. total fluid in 2 hrs. 15 min. (Will drain off water 11-18-83 a.m.) Casing pressure when well kicked off 1450 psi. After flowing through open 2" line 2 hrs. 15 minutes casing pressure 900 psi. Shut well in overnight.

1st new oil to tank

11-18-83 Casing pressure 1050 psi. Tubing pressure 925 psi. Tank gauge after draining all water 2'1" (42 bbls.) Opened well to tank. Flowed for 40 min. and died. Casing pressure came up to 1400 psi. Made 7 swab runs (fluid level 1st swab run 2400'). Well kicked off and flowed 4 hrs. Drained all frac water from tank. Gauge after draining water 7'1" (142 bbls.). Swabbed and flowed 100 bbls. oil in 7 hrs. - undetermined amount of frac water and no estimate on gas. Shut well in at 4:00 p.m. 11-18-83. Will set production unit Monday 11-21-83 to get I.P. test. Casing pressure 925 psi when well closed in.

11-19-83 SICP 1375 psi. SITP 900 psi. Drained all water from tank - from 7'1" to 5'4" - total oil in tank 106 bbls.

Figure No. 1



T-25-N, R-2-W, NMPM
Rio Arriba County, New Mexico

OFFSET OPERATORS

Jerome P. McHugh (MCH)
650 S. Cherry St., #1225
Denver, CO 80222

Dugan Production Corp. (DPC)
P.O. Box 208
Farmington, NM 87499

Gulf Oil Corporation (GULF)
P.O. Box 1150
Midland, TX 79702

Northwest Exploration Company (NWE)
P.O. Box 1526
Salt Lake City, UT 84110

Northwest Pipeline Corporation (NWP)
P.O. Box 1526
Salt Lake City, UT 84110

Southland Royalty Company (SRC)
410 17th Street, Suite 1000
Denver, CO 80202

Kenai Oil and Gas, Inc. (KENAI)
1675 Larimer St., Suite 500
Denver, CO 80202

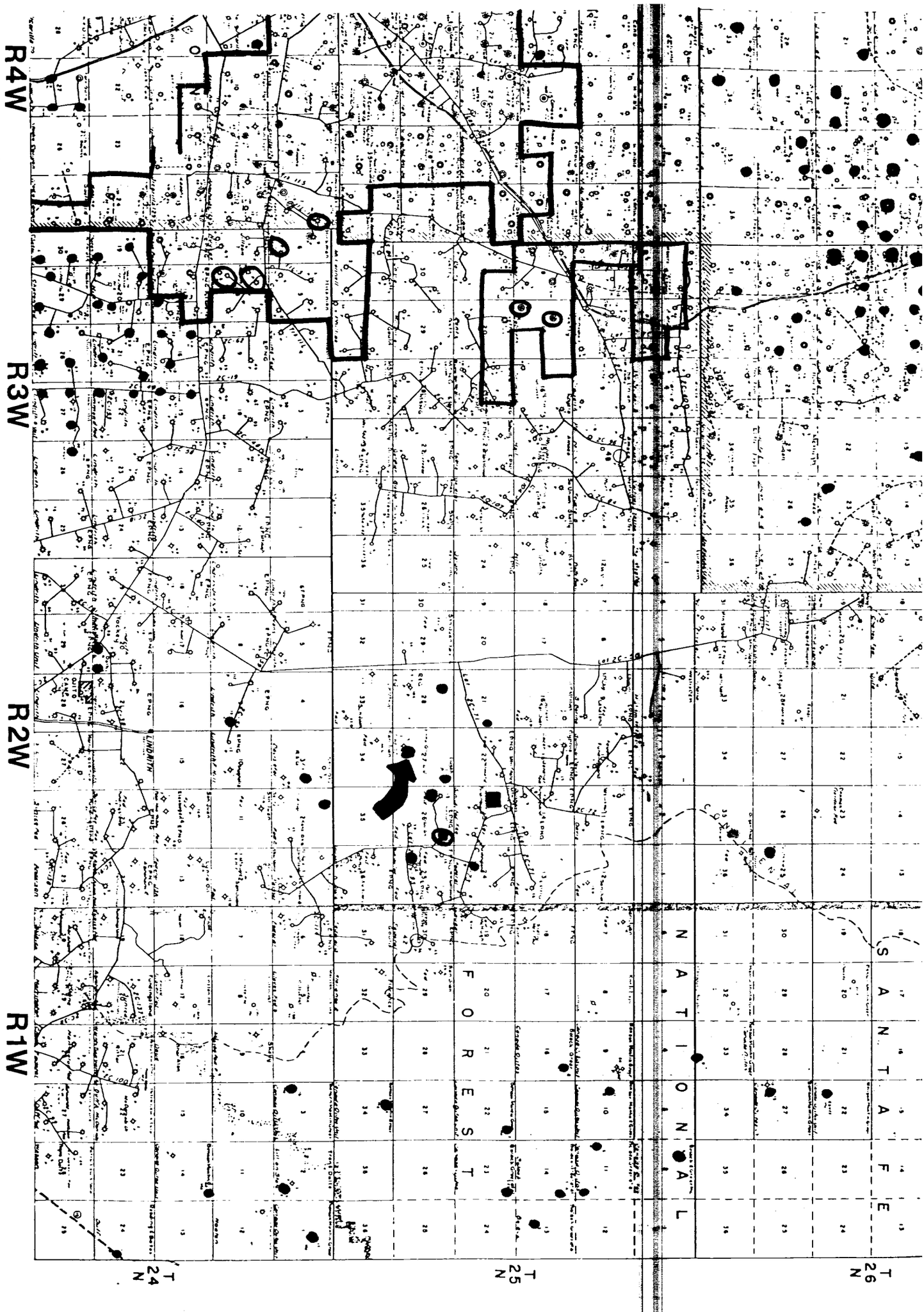
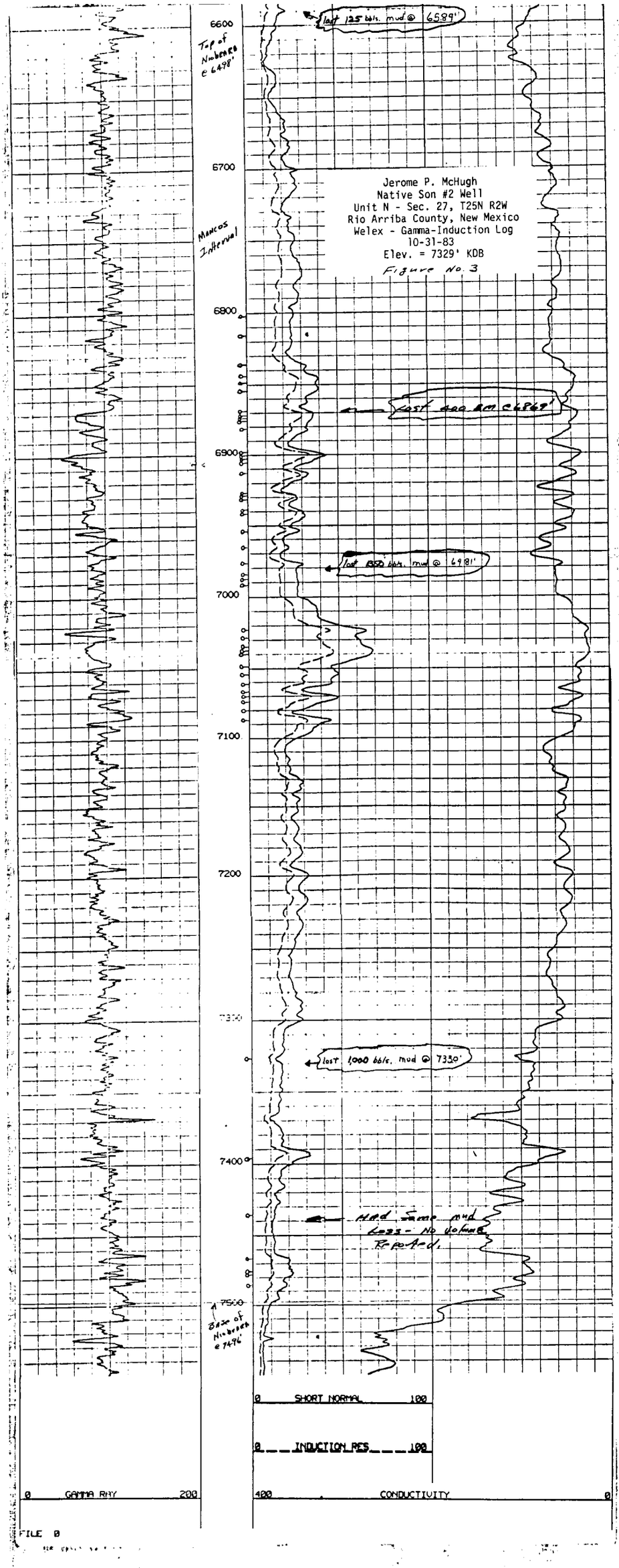
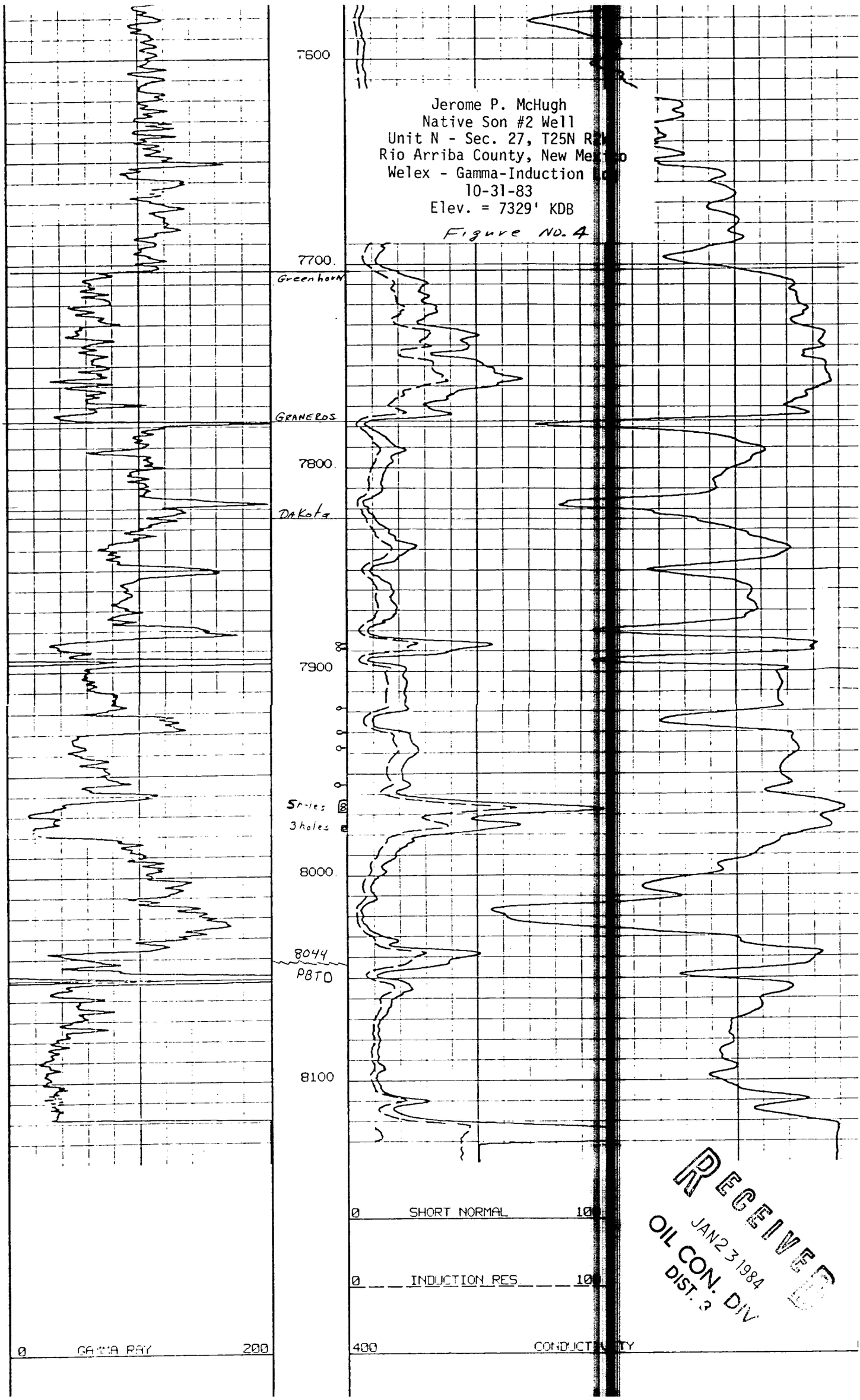
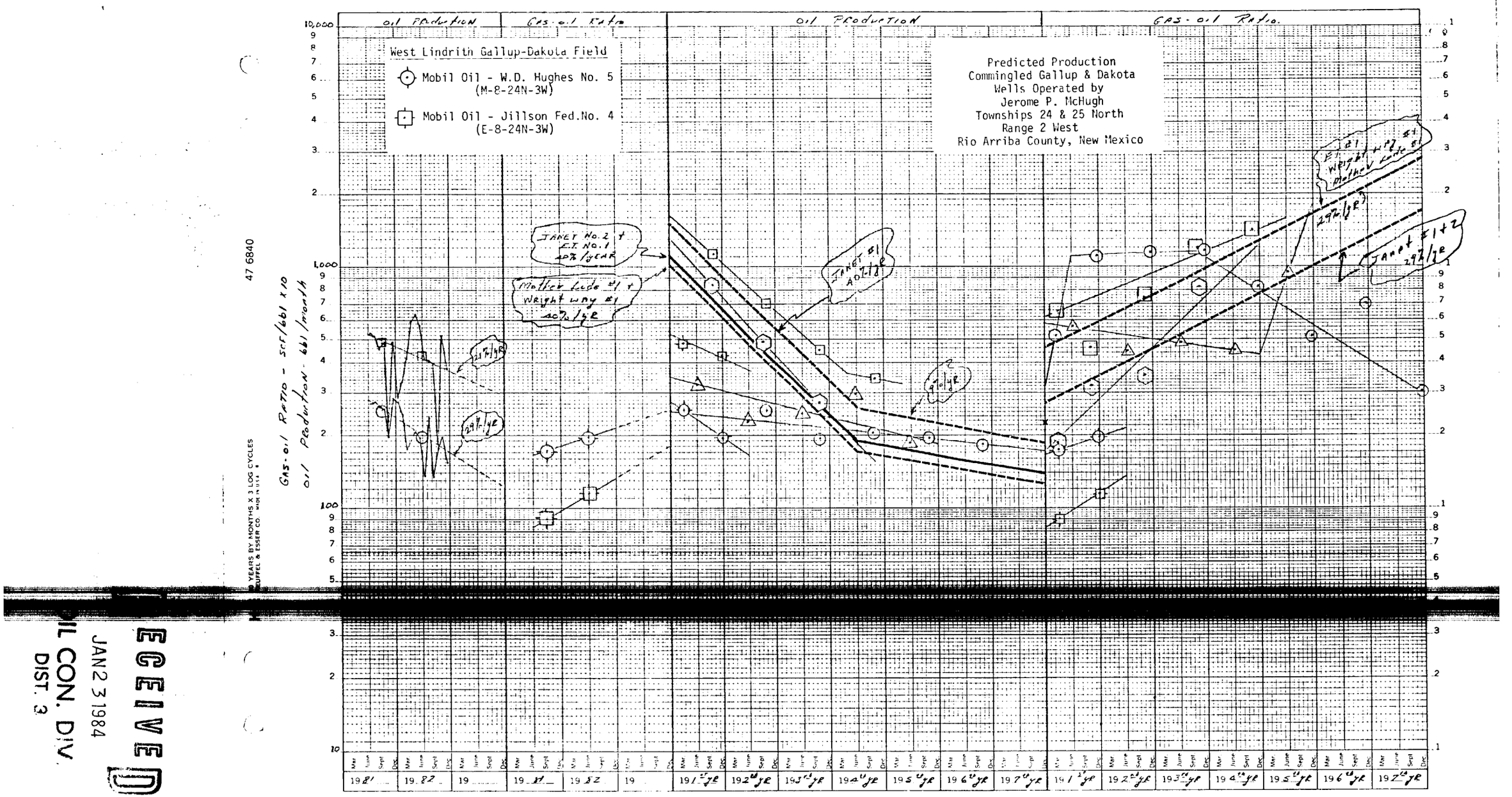


Figure No. 2

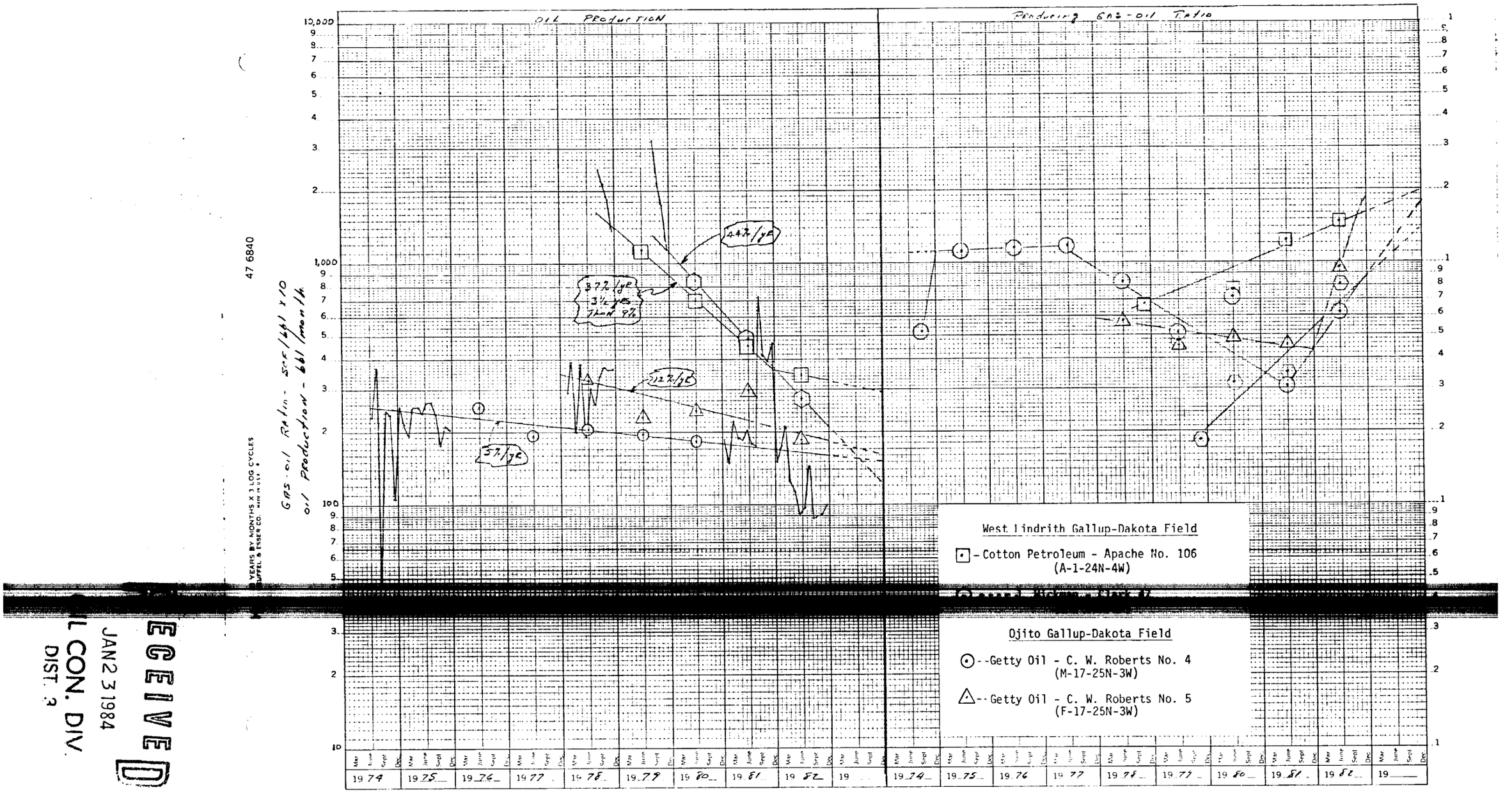






RECEIVED
JAN 23 1984
OIL CON. DIV.
DIST. 3

Figure No. 6



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DIST. 3

WELL DATA
Commingled Gallup-Dakota Wells
General Area of Jerome P. McHugh's Wells in
Townships 24 and 25 North, Range 2 West
Rio Arriba County, New Mexico

Operator	Well Name	Location U-S-T-R	Initial Potential BOPD-GOR	Actual Init.Prod. BOPD-GOR	Oil Production: Production Factor Actual/IP	Oil Production: Initial Decline %/Yr-Yrs	Oil Production: Stabilized Decline % / Yr	Gas Production: Gas Prod. Factor Actual/IP	Gas Production: Incline Rate %/Yr	Cummulative Oil Prod. 1-1-83 - Bbl	Estimated Ultimate Recovery-Bbl
West Lindrith Gallup-Dakota Field											
Cotton Petroleum	- Apache No. 106	A-1-24N-4W	97 - 1526	53 - 6400	55%	37 - 3½	9	4.19	25	41,254	76,800
J. Hickman	- Clark No. 7	O-6-24N-3W	150 - 2666	43 - 1800	29%	44 - --	-	0.68	57	28,209	49,200*
Mobil Oil	- W.D. Hughes No.5	M-8-24N-3W	28 - 179	9 - 1670	32%	29 - --	-	9.33	19	3,675	12,000*
Mobil Oil	- Jillson No. 4	E-8-24N-3W	35 - 857	18 - 840	51%	21 - --	-	0.98	39	7,828	38,500*
Ojito Gallup-Dakota Field											
Getty Oil	- C.W. Roberts No. 4	M-17-25N-3W	9 - 12,220	8 - 11,000	-	5 - --	5	0.90	5	21,087	48,000
Getty Oil	- C.W. Roberts No. 5	F-17-25N-3W	NR - 4,850	12 - 5,800		12 - --	12	1.20	-	14,131	27,200
6 Well Average			64 - 3,716	24 - 4,585	42%	33 - --	9	1.23	29		41,950

decline rate of 9%

Table No. 1

MANCOS[A]-DAKOTA WELL DATA
Gavilan Area
Rio Arriba County, New Mexico

Well Name	Location[D] U-S-T-R	Sequence Drilled	KB Elev.	Spud Date	CASING Surface	CASING Production	Completion Date	MANCOS[A] ZONE Perfs	MANCOS[A] ZONE BOPD @ GOR	DAKOTA ZONE Perfs	DAKOTA ZONE BOPD @ GOR
Jerome P. McHugh											
Janet #1	A 27-25N-2W	2	7253	11-16-82	9-5/8 @ 211'	4-1/2 @ 7958'	2-17-83	6689-7000	73 @ 2753	7740-7869	43 @ 1047
Janet #2	I 21-25N-2W	3	7197	3-31-83	8-5/8 @ 205	4-1/2 @ 8057	9-1-83	6657-7055	60 @ 3000	7841-7994	36 @ 1111
E.T. #1	C 28-25N-2W	4	7170	4-25-83	9-5/8 @ 220	4-1/2 @ 8081	9-19-83	6643-7025	96 @ 5219	7747-8033	18 @ 1833
Wright Way #1	C 2-24N-2W	6	7329	5-24-83	9-5/8 @ 245	4-1/2 @ 8182	9-29-83	6760-7072	51 @ 6000	7865-8141	27 @ 2000
Mother Lode #1	H 3-24N-2W	7	7333	6-13-83	9-5/8 @ 224	4-1/2 @ 8248	9-2-83	6765-7070	63 @ 5190	7861-8108	15 @ 2200
Native Son #2	N 27-25N-2W	10	7329	10-8-83	9-5/8 @ 224	4-1/2 @ 8133	11-18-83	6802-7485	233 @ 1882	7886-7977	58 @ 3824
Northwest Exploration											
Gavilan #1	A 26-25N-2W	1	7467	12-26-81	9-5/8 @ 540	4-1/2 @ 8240	3-21-82	6821-7562	62 @ 8790[B]	7879-8026	B
Gavilan #1E[C]	E 26-25N-2W	5	7319	5-15-83	9-5/8 @ 278	4-1/2 @ 8159	7-23-83	6804-7366	32 @ 11,700	7822-7918	10.2@3400
Northwest Pipeline											
Rucker Lake #1	G 23-25N-2W	9	7309	Location							
Rucker Lake #2	K 24-25N-2W	8	7396	7-12-83	9-5/8 @ 522	4-1/2 @ 8155	8-26-83	6825-7484	193 @ 1200	---	---
Rucker Lake #3	L 25-25N-2W		7408	6-15-83	9-5/8 @ 384	5-1/2 @ 7560	8-10-83	6808-7538	145 @ 2089	---	---
Rucker Lake #4	J 25-25N-2W		7448	Location							
Mesa Grande Resources											
Gavilan-Howard #1	F 23-25N-2W	11	7294	10-10-83	8-5/8 @ 200	5-1/2 @ 8010	WOCT	---	---	---	---

A Also referred to as "Gallup"
B Commingled with Dakota
C Cemented 7" casing @ 6070' & also completed Greenhorn 7653-7708' with IP of 9.8 BOPD with GOR = 2510
D Surveyed Locations: Janet #1 790' FNL - 790' FEL, Janet #2 1850' FSL - 790' FEL, E.T. #1 1100' FNL - 1600' FWL, Wright Way #1 950' FNL - 1650' FWL, Mother Lode #1 1730' FNL - 860' FEL, Native Son #2 1020' FSL - 1670' FWL; Gavilan #1 930' FNL - 910' FEL, Gavilan #1E 1850' FNL - 990' FWL; Rucker Lake #1 2270' FNL - 2275' FEL, Rucker Lake #2 1450' FSL - 1520' FWL, Rucker Lake #3 1760' FSL - 940' FWL, Rucker Lake #4 2060' FSL - 1740' FEL; Gavilan-Howard #1 1850' FNL - 1651' FWL

Table 1.0 2

open hole Log Evaluation

Jerome P. McHugh - Native Son #2

Dakota

Perforations	Pay ft.	ϕ %	S_w %	Primary-Secondary	Remarks
7886-88	2	5	?	S	
7919	1	11	"	S	
7930	2	6	"	S	
7938	1	6	"	S	
7955	1	8	"	S	
7963-69	4	5	"	S	
"	2	7½	≤48%	P	GAS effect on FDC/CNL
7975-77	2	9	≤51%	P	
TOTAL	15	$\bar{\phi}$ = 6.7%			

4 ft primary w/ $\bar{\phi}$ = 8.25%

11 ft Secondary w/ $\bar{\phi}$ = 6.10%

Mancos

Perforations	Pay ft	ϕ %	Primary Secondary	Remarks
6802	1	16	S	Shaley
6816	1	13	"	
6836	2	13	"	
6844	1	12	"	
6849	1	15	"	
6853	1	14	"	
6869-75	5	?	P	Lost 400 bbl mud - Fractured.
6881	2	?	P	
6898-6904	5	?	P	
6913	2	11	P	
6927-31	2	?	S	
6939-41	2	?	"	
6953	2	21	"	Shaley
6965	1	?	"	
6977	2	11	P	Lost 1350 bbl mud - Fractured - GR indicates to be Shaley.
6983-91	2	15	P	
"	2	14	P	
7023	2	10	P	
7029-39	1	17	S	Shaley
"	1	16	"	"
"	1	17	"	"
"	1	15	"	"
7049	1	15	"	"
7053	1	15	"	"
7061	1	15	"	"
7066	2	27?	"	Dolomite? by Log x plot.
7070	1	15	"	Shaley
7073	1	15	"	"
7080	1	14	"	Dolomite by Log x-plot.
7087	1	9	"	
7326	1	17	P	Lost 1000 bbl mud - Fractured
7394	1	14	S	
7436	2	?	P	Lost Some mud - volume Not Reported
7466	2	8?	S	Shaley
7475	1	12?	"	"
7478	1	5?	"	"
7485	1	3?	"	"
	58	w/ $\bar{\phi}$ = 14%. (Actually only 39' included in Average as 19' had questionable ϕ due to hole Rugosity)		

25 ft primary w/ $\bar{\phi}$ = 12.67% (14 ft of questionable ϕ)

33 ft Secondary w/ $\bar{\phi}$ = 15.1%

Table No. 2 (Continued)

Native Son No. 2

NOTES:

1. The distinction between primary and secondary pay was based upon several factors: sample description, drilling breaks, SP development, sample shows, and shale content based upon the GR curve.

   Primary pay is expected to contribute significantly to productivity.

   Secondary pay is not expected to significantly contribute to production, but exhibits sufficient potential to perforate.

2. In both Mancos and Dakota intervals, there are no sands thick enough to accurately measure R_t (thin bed effect). This is complicated by a fairly high shale content in most intervals. An average S_w of 40% is believed to be typical to both zones in other fields and where S_w calculations could be approximated, values of 40% were indicated.

Table No. 3
Jerome P. McHugh
Native Son No. 2

Estimate of Ultimate Recovery

A. Commingled well stream - projected performance:

1. Reference Figure No. 5 and No. 6.

2. Anticipated sustained production performance - 1st month's average = 42% of IP and declining at 40% per year then stabilize at 9%.

3. IP Summary

	BOPD	MCFD	BWPD	GOR
Mancos	233	440	34	1,882
Dakota	58	223	34	3,824
Total	291	663	68	2,278

4. 42% of IP = 291 BOPD x .42 = 122 BOPD
= 3,700 BO/Month.

5. Economic Limit - operating expense approx. $1,350/month.
At end of life GOR will be approx. 10,000;
therefore, approx. revenue per bbl. oil approx.
(1 BO x 29.60) + (10 MCF x 2.82 x 1.20)
= $63.44 with gas sales.
Opex = 1,350 / 63.44 x .85 x .92 x 30.4 = 0.9 BOPD

Ultimate recovery: (3,700 - 620) x 23.5 + (620 - 30) 127.2
= 72,380 + 75,020
= 147,400 BO

B. Split of production between zones:

1. Volumetric calculations do not give realistic results in the Mancos interval, however, are believed to be fairly accurate in the Dakota.

2. Mancos recovery will be greatly influenced by natural fracturing and the natural fractures may, to a lesser degree influence production in the Dakota.

3. Volumetric recovery factors:

	Mancos	Dakota
Mid-perf Datum	7,144'	7,932'
BHP at Datum,[a] psig	1,690	2,674
BH temperature at Datum - °F	166	179
Estimated Solution GOR - SCF/B	500	1,000
Estimated oil FVF - RB/STB	1.33	1.52
Oil Recovery Factor[b] - % OIP		
Primary Pay	?	5%
Secondary Pay	?	0.5%

Notes: a - Mancos BHP determined to be 1,663 psig at 7,200' from build up in Gavilan #1. Dakota BHP was measured to be approximately 2,600 psi at 7,900' on a 132 hr build up in the Gavilan #1.

b - estimated for Solution gas drive.

Dakota Rsrv: [7,758 x 320A x 4' x .0825 x (1 - .40) / 1.52] .05 +
[7,758 x 320A x 11 x .061 x (1 - .40) / 1.52] .005
= 16,170 + 3,290
= 19,460 STB ⟶ 19,500 STB

Table No. 3 (Continued)

Native Son No. 2

Gas Rsrv: An overall average GOR of 3500 SCF/STB is estimated based upon testing of the Dakota in the Gavilan area.
Therefore, ultimate gas recoveries = 19,500 x 3.5
= 68.2 MMCF

Mancos Rsrv: Ultimate recovery - Dakota volumetric Rsrv
: 147,400 - 19,500
= 127,900 STB

Gas Rsrv: An overall average GOR of 10,200 SCF/STB is estimated based upon performance of wells in Gavilan area and in Lindrith Gallup (gas) Field.
Therefore, ultimate gas recoveries = 127,900 STB x 10,200
= 1,304.6 MMSCF

RESERVE SUMMARY:

	Mancos	Dakota	Total
Oil	127,900 (87%)	19,500 (13%)	147,400
Gas	1,304.6 (95%)	68.2 (5%)	1,372.8

Table No. 4
ALLOCATION FACTORS FOR
COMMINGLED MANCOS-DAKOTA WELLS
Townships 24 and 25 North, Range 2 West
Rio Arriba County, New Mexico

	Well and NMOCD Commingling Order No.					
	Janet No. 1 R-7258	Janet No. 2 R-7312	E. T. No. 1 R-7366	Mother Lode No. 1 R-7365	Wright Way No. 1 R-7367	Native Son No. 2 Proposed
OIL						
Mancos	63%	75%	84%	79%	67%	87%
Dakota	37%	25%	16%	21%	33%	13%
GAS						
Mancos	82%	90%	94%	91%	85%	95%
Dakota	18%	10%	6%	9%	15%	5%