STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
15 February 1984

EXAMINER HEARING

IN THE MATTER OF:

Application of Jerome P. McHugh for downhole commingling, Rio Arriba County, New Mexico.	CASE 8041

BEFORE: Richard L. Stamets, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:	W. Perry Pearce, Esq. Legal Counsel to the Division State Land Office Bldg. Santa Fe, New Mexico 87501
For the Applicant:	Tommy Roberts, Esq. Dugan Production Company P. O. Box 208 Farmington, New Mexico 87401

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EXHIBITS

MR. STAMETS: We'll call next Case 8041.

MR. PEARCE: That case is on the application of Jerome P. McHugh for downhole commingling, Rio Arriba County, New Mexico.

MR. ROBERTS: My name is Tommy Roberts, on behalf of the applicant, Jerome P. McHugh.

I have one witness to be sworn.

MR. PEARCE: Are there other appearances in this matter?

(Witness sworn.)

JOHN ROE,

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

DIRECT EXAMINATION

BY MR. ROBERTS:

Q Would you state your name, please?

A My name is John Roe.

Q And your place of residence and your occupation?

A I live in Farmington, New Mexico. I'm a petroleum engineer employed by Dugan Production and we're representing Jerome P. McHugh.

Q Have you testified on previous occasions before the New Mexico Oil Conservation Division?

A Yes, I have.

Q And are you familiar with the application in this case?

A Yes, I am.

MR. ROBERTS: Mr. Examiner, are Mr. Roe's qualifications as an expert in the field of petroleum engineering a matter of record and acceptable?

MR. STAMETS: Yes.

Q Mr. Roe, would you briefly state the purpose of this application?

A We are making application to the Oil Conservation Division to commingle within the wellbore production from 320-acre spaced Gavilan Mancos and 320-acre Basin Dakota. This would be commingled downhole within the wellbore of the Native Son No. 2, which is operated by Jerome P. McHugh.

This well is located in Unit M of Section 27, Township 25 North, Range 2 West, and the production unit for both horizons is comprised of the south half of Section 27.

Q Mr. Roe, would you refer to your Exhibit Number One and identify that exhibit?

A Okay. Exhibit Number One is a plat on which we've indicated the various leases within the proration unit for the Native Son No. 2, and as I indicated, that was the south half of Section 27 and in addition we've indicated the ownership of the immediately adjacent offsetting leases.

As a matter of interest, Jerome P. McHugh and Dugan Production jointly own approximately 40 percent of the acreage that does offset this proration unit.

Q Is this well located at a standard location?

A Yes, it is.

MR. ROBERTS: Mr. Examiner, for the record at this point I would like to point out that we hae received waivers of objection to our request for administrative approval of this matter from all of the offset operators listed here except Northwest Pipeline Corporation.

Q Mr. Roe, would you now refer to what's been marked as Exhibit Number Two and identify that exhibit and explain its significance?

A Yes. Exhibit Number Two is intended to show the general area of the Native Son No. 2, the wells that are completed in the Gallup or Dakota and also the wells that are currently commingled within the Gallup and Dakota.

Indicated in the light blue dots would be the Gallup or Mancos production that is current. The light -- the green dots indicate wells that are currently producing from the Dakota. Indicated in the purple dots would be wells that are currently commingled, both zones, Gallup and Dakota, within the wellbore.

I have indicted outlined in orange the boundary of the West Lindrith Gallup Dakota, which is located approximately 8-1/2 miles to the west of the Native Son No. 2, and outlined in red would be the field boundaries of the Ojito Gallup Dakota Field, which is approximately 8 miles to the northwest.

Also, I'd like to -- indicated in the red circles would be wells that have some production history that we've utilized to draw an analogy to, and this is a fairly recently developed area, very little production exists from the immediate vicinity and we've had to go remote from where we're at to develop any production characteristics.

The wells that I've used for analogy I've indicated with a red circle.

Q Mr. Roe, are you able to draw any conclusions with regard to your application in this case from the data that's reflected on this exhibit, or is it merely an informational type exhibit?

A Well, it basically is intended for just a general idea of the area we're dealing with; however, from the exhibit it can be seen that within the immediate vicinity that we're calling the Gavilan Mancos Basin Dakota Pool, and the Native Son No. 2 is located within, there's eleven wells. Of these eleven wells five of them have previously been authorized to commingle production within the wellbore, as we're requesting for the Native Son No. 2.

Two of these have recently been before the Commission to request permission to commingle. That would be the Gavilan 1 and 1-E, located in the north half of Section 26, and I am not aware that they have been granted permission to commingle downhole but they were heard.

Of the eleven, two of the wells were not drilled, or have not been completed in the Dakota, and one of the wells has been drilled and the intentions are to complete in the Gallup Dakoat, but as yet have not done so.

So the majority of the wells in the immediate vicinity are commingled as we're asking for Native Son No. 2 and commingling is a common occurrence in the West Lindrith Gallup Dakota and all these are Gallup Dakota.

Q Would you refer to Exhibit Number Three and identify it?

A Exhibit Number Three is a reproduction of the open hole induction electric log that was recorded during the drilling process. It was logged on October 31st, '83.

Exhibit Three is a copy of this log over the Mancos interval. We've indicated the perforations, the top shot being at 6802 and the bottom perforation, 7485.

We have completed a 683-foot gross interval and within this 683-foot gross interval we feel we've -- or attempted to develop 33 separate intervals. Detailed analysis of the logs indicates there's 58 feet of pay within this interval, of which 25 feet of it would have reservoir characteristics that I would expect it to produce the majority of the production.

33 feet would have enough potential that we felt it was worth perforating but it's either too shaley or a very thin zone and probably will not significantly contribute to reserves.

We do feel that we have completed all of the potential that exists within the Mancos interval.

Q Refer to Exhibit Number Four and identify that exhibit.

A Okay. Exhibit Number Four is a copy of the induction electric log, the same log that was presented on our Exhibit Three but only over the Dakota interval. We've indicated the top of the Dakota at 7825. Our perforations are indicated on the depth channel of the log, the top shot being at 7886 and the bottom at 7977.

We've perforated an overall interval of 91 feet. Within this 91-foot interval we feel we've developed seven separate and distinct intervals within the Dakota. The Dakota is not well developed at this location. Detailed log analysis would indicate fifteen feet of total pay. Of the fifteen feet, four feet with an average porosity of 8-1/4 percent would likely be fairly productive and contribute a most -- majority of the production that will come from the Dakota.

There's an additional eleven feet that we feel is productive but not -- to a lesser degree.

Q Is it you opinion that you have perforated all of the potentially productive intervals within the Dakota section?

A Yes, we have. There is a little interval there right at 8040 that in other wells has been of some interest to us, but each time we've perforated this zone it's proven to be water productive.

So we feel we've perforated and stimulated all intervals that exhibit potential within the Dakota.

Q Refer to Exhibit Number Five and identify it and briefly summarize its contents.

A Okay, Exhibit Number Five is a copy of our daily drilling -- of our daily reports during the drilling and completion process of this well.

To just highlight briefly, the well was spudded on October 8th, 1983. 9-5/8ths casing was cemented at 224 feet with 135 sacks of cement.

During the drilling process there were several intervals in the Mancos, beginning on October 21st, that we lost circulation. The exact volumes of mud that were lost are indicated on the daily reports.

We had a severe lost circulation at one point in the well. This interval is indicated on Exhibit Number Three. We were able to resume drilling and TD'ed the well. We cemented 4-1/2 inch, 11.6 pound casing at TD of 8133. We cemented this casing in three stages with a total of 2743 cubic feet of cement.

We began our completion efforts on November 11th and involved perforating the Dakota and a lower portion of the Mancos. We fracture stimulated both intervals using a total of 60,000 gallons of jelled water and 67,500 pounds of 20/40 sand.

We then perforated the main Mancos interval, which would be 6802 to 7087 and we fracture stimulated this interval with a total of 70,000 gallons of water, 89,500 pounds of 20/40 sand.

We began testing of the well on November 14th with a swab unit and during the first day of swabbing we started picking up a fairly good gas show, which would indicate the well was going to be better than normal. Normally we don't start seeing hydrocarbons until the third or fourth day.

The well actually kicked off and flowed on the fourth day and we were able to file a potential test on November 18th, reflecting a daily rate of 233 barrels a day from the Mancos and 440 Mcf a day, and from the Dakota 58 barrels a day, barrels of oil a day, and 223 Mcf of gas a day.

Since we filed a potential on the well we have, under a temporary testing allowable, we've flow tested the well intermittently, attempting to clean the well up from the frac load plus get a better idea of what kind of artificial lift equipment is going to be necessary. The well will not flow up the tubing. It will flow up the casing. We're reluctant to flow it up the casing because there is a paraffin deposition that occurs from both the Mancos and the Dakota oils.

We anticipate having to install artificial lift equipment and currently the well is being intermittently produced for evaluation purposes. We have very little storage on lease. It's a small location and we're in close proximity to a residence and so we're not even going to leave the well flowing up the casing for any length of time, just because of limited storage and we don't want to flow it up the casing.

Q Okay, Mr. Roe, would you refer to Exhibit Number Six, please, and identify that exhibit?

A Okay. Exhibit Number Six is a presentation of what went into my calculation of the estimate of ultimate recoveries from this well.

As I indicated, our initial potential was a total of 291 barrels a day; 233 barrels a day from the Mancos and 58 from the Dakota.

Utilizing some data from other wells in the area, which were presented on Exhibit Number Two, we developed some factors that --historically stabilized first month's production would -- would reflect a value that would be approximately 42 percent of the reported initial potential.

Utilizing our 291 barrels a day, 42 percent of this would be a value of 3700 barrels a month.

Also utilizing other wells we developed an anticipated production decline that would be 40 percent for the first 3-1/2 years and then stabilize at 9 percent. Utilizing this trend of production, which is derived using data from six other wells, ultimately we would expect recoveries from this well would be 147,400 barrels of oil.

This is definitely one of the better wells in the general area. It is a real surprise to us.

At any rate, that's much better than we anticipated.

On the second page, well, on the first page, bottom part under Item B, we've detailed our efforts to allocate the reserves between the Dakota and the Mancos. We've made a volumetric calculation for the Dakota interval, primarily because we feels that volumetrics give a fairly representative number in the Dakota.

The Mancos being fractured as it was and probably more severely fractured in this well than any other well we've drilled, as evidenced by the lost circulation that we had when we drilled it, we've determined the Mancos reserves by subtracting that that would be allocated to the Dakota from our anticipated ultimate recovery, utilizing our decline trend that was established from six other wells.

This would indicate that ultimate recoveries from the Mancos would be 127,900 barrels of oil, and on the bottom part of the second page of Exhibit Number Six

I've summarized the reserves that are presented on Exhibit Number Six and indicated what percent would be attributable to each zone.

Of the total 147,400 barrels 87 percent of that would be coming from the Mancos and 13 percent would be attributable to the Dakota.

Utilizing data from the six wells that I've mentioned previously, plus the GOR data of wells in the immediate vicinity, we've established our ultimate gas reserves, 1304.6 million to the Mancos and 68.2 million for the Dakota.

Utilizing those reserves we allocated 95 percent of total production to the Mancos and 5 percent of the total gas to the Dakota. These percentages are the allocation factors that would propose to allocate production of the commingled stream.

Q Are these allocation percentages consistent with other wells in the area which have been authorized for downhole commingling?

A Yes, they are. We'll have on our final exhibit, I have a summary of those.

Also attached, the latter two pages of Exhibit Number Six, is a presentation of the actual log analysis that I've utilized -- that I derived the reservoir parameters from, that went into the volumetric calculations.

Q Mr. Roe, in Exhibit Six you have set forth some -- some predictions or some estimates of productive potential from this well. Would you expect this productive performance of the well that you predict to differ if you were required to complete and produce each zone separately?

A The actual projection I wouldn't expect to be a whole lot different, as far as the 40 percent decline and the 9 percent stable production; however, our ultimate recoveries would be smaller by the amount of production that we have estimated to be attributable to the Dakota for the reason that with the 4-1/2 inch, 11.6 pound casing and the need to artifically lift each zone, or rod pump each well, we do not believe that dual completion is feasible, so my forecast would not change but it would be a total -- ultimate recovery would be smaller.

Q Please refer to Exhibit Number Seven and identify that exhibit and explain its significance to this application.

A Okay. Exhibit Seven is, on the production rate/time curve 22, reflecting 22 months of production from the Gavilan No. 1, which is a well operated by Northwest Exploration in the northeast quarter of Section 26, 25 North, 2 West. This is a well approximately 1.7 miles to the northeast of the Native Son. We've indicated the production performance to date, and as you can see, the first 22 months the production has continued to improve. It's currently averaging right at 100 barrels a day.

I have also, on this production plot, indicated our predicted future production for the Native Son No. 2, and as I've indicated, I'm utilizing a 40 percent annual decline rate for the first 3-1/2 years and then a stabilized decline rate of 9 percent, which is some factors that I arrived at utilizing production data from other wells in the general area that have an adequate length of time on production to determine these factors.

The six wells that I used to get these factors are presented on the last three pages of -- that are attached to Exhibit Number Seven.

Q Please refer to Exhibit Number Eight, Mr. Roe, identify that exhibit.

A Okay. Exhibit Number Eight is a tabulation of the production and some of the completion data for all eleven wells that have been completed in the immediate area of the Gavilan Mancos Basin Dakota Pool that we're -- that the Native Son No. 2 is located.

I've indicated on the tabulation the production casing of the eleven wells that have been cased, none of them have been completed utilizing 4-1/2 inch casing. Our well, as I've indicated earlier, was spudded on October 8th, 1983. It was the tenth well to be drilled. There is one well that's been drilled but not completed since the Native Son No. 2 and there is also one well that's currently at TD and logging.

I've also indicated in the righthand portion of the tabulation the initial potentials that have been reported on the wells that have reported IP's, and based upon initial potential, it appears the Native Son No. 2 is -- will by far be the most productive well in the general area.

Q At the time the Native Son No. 2 Well was spudded, what type of production history did you have from other wells in the area?

A At the time the Native Son No. 2 was spudded the only well that had any sustained production at all was the Gavilan No. 1, which that production history is presented on Exhibit Number Seven.

Jerome P. McHugh had completed and had a very minor amount of production from the six wells we have previously operated; however, the six wells that we operate, none of them would flow naturally and all required artificial lift. Rod pumps were installed in the early part of November in all six wells. And so at the time we spudded the Native Son, we basically had the reported IP's and a very minor amount of production. It required swabbing to refer to it. We did not expect a well of the quality of the Native Son No. 2.

Q I note from the data contained in this exhibit that it's common procedure to set 4-1/2 inch casing in this type of well. Do you concur that that's standard, prudent operating procedure in this area?

A Yes, as I've indicated, of the eleven wells presented, nine of them were completed utilizing 4-1/2 casing. We're in an area that -- that there's many drilling problems. We're looking at fairly expensive wells. 4-1/2 casing is one of the methods that we've been using to control our cost.

Q Mr. Roe, I don't believe you mentioned the second page of the attachment to this Exhibit Number Eight. Would you explain the reason for its inclusion with this exhibit?

A Okay. It is attached as a matter of reference. It shows the relative position of the Native Son No. 2. It's a plat, a map of the general area, a little larger scale than that that was presented in the Exhibit Number Two. The intention here was to show the location of the Native Son No. 2 with respect to the offsetting wells.

We have both Gallup and Dakota completed in the ET No. 1, which is located to the northwest approximately one mile.

We have Gallup and Dakota in the Janet No. 2 to the north and also in the Janet No. 1 to the northeast within the same section as the Native Son No. 2.

Gallup Dakota is also completed in both of the Northwest Exploration wells, located in the north half of Section 26 and also Gallup and Dakota is being produced to the south in the Mother Lode and the Rightway.

Q Let's move on to your Exhibit Number Nine. Identify that exhibit, please.

A Okay. Exhibit Number Nine is included

for reference purposes. We've indicated for the five wells that Jerome P. McHugh has previously received permission to commingle production from the Gallup and -- or Mancos and Dakota, we've indicated allocation factors that were authorized, the order numbers that those factors were authorized, and also we've indicated the proposed allocation factors for the Native Son No. 2.

Q Mr. Roe, is ownership of the Mancos and Dakota zones common?

A Yes, the ownership is. The production units, by virtue of a recently issued Mancos, Gavilan Mancos Pool, which will be effective March 1st of 1984, both units are spaced on 320 and all ownership is common.

Q And to your knowledge there's no vertical separation or segregation of ownership?

A As our records, that is correct, according to our best information.

Q Mr. Roe, do you have measured bottom hole pressure figures for either zone?

A We have not measured bottom hole pressure in either zone in the Native Son No. 2; however, we do have measured bottom hole pressure recorded with the pressure build-up in the Gavilan No. 1, which is located to the northeast of the Native Son No. 2, approximately 1.7 miles to the northeast. The data was -- utilizing the data that was a bottom hole pressure build-up in both zones, working that up, utilizing acceptable methods for analyzing pressure build-up, we've established that the bottom hole pressure in the Native Son No. 2 is 1690 psi at a mid-perf datum of 7144.

Also the pressure in the Dakota would be 2674 psi at a mid-perf datum of 7932.

The pressures that were recorded in the Gavilan No. 1 have been found to be fairly representative of pressures in other wells that we've completed and we have no reason to think they would be different in the Native Son No. 2.

Q In your opinion is there any danger of cross flow between the zones due to pressure -- to this pressure disparity?

A I believe that cross flow will be no problem. There is a pressure gradient difference between the two zones; however, the pressure difference is within that permitted by State law, State rules.

Q Would you expect the fluids to be produced from each zone to be compatible with one another?

A Yes. The oil and gas is similar in qualities in both zones and we have no information that would suggest there's a problem in commingling.

Q And are we dealing with fluid sensitive sands in these formations which may be subject to damage from water or other produced liquids?

A No. Both zones were stimulated with water based fluids.

Q Mr. Roe, for a minute here I would like to have you address the economics of the Dakota formation.

First of all, based upon your estimate of reserves which you've attributed to the Dakota formation, could you -- could you discuss economics of Dakota formation completions in those terms basis?

A Yes. The Dakota formation with -- making reference to Exhibit Number Six, we feel ultimately will result in recovering 19,500 barrels of oil and 68.2 million cubic feet of gas.

This is a volume of oil that is definitely commercial to recover, if you don't have to spend a lot of money to get to it. The average well cost, if we were required to drill only for Dakota production, is $625,000 for wells in this area, and they've ranged from a low of about $450,000 to a high of $1.2 million.

The Dakota does not have the potential that would encourage anybody to drill a well for Dakota only. The Dakota, our anticipation based upon our initial potential of 58 barrels a day, if our 42 percent factor holds, which we have every reason to believe it will, we would expect early rates in the Dakota to be 24 barrels a day and decline at a rate of 40 percent per year.

So we don't believe that the Dakota warrants development on its own. The only way that the Dakota reserves will ever be realized is either commingled with the Mancos or produced at a later date at some time in the future if the wellbore is still usable.

Q Would you address the question of the feasibility of dually completing the well inside 4-1/2 inch casing?

A Okay. With the 4-1/2 inch casing and the need to rod pump or artificially lift both zones, we just don't believe that it's feasible. The largest string of tubing that would fit inside the 11.6 pound 4-1/2 is two strings of inch and a quarter interval joint tubing, and there is no way we could artificially lift either zone efficiently and there is a substantial amount of gas associated with both zones, neither one of which would be an effective rod pump operation below a packer.

In addition to that, there's no wellhead equipment available to accept two strings of tubing on 4-1/2 casing.

Q What would be your recommendation to the applicant in this case in terms of operating procedure in the event this application is not granted?

A Well, we -- we firmly believe that the Mancos is the primary objective in this area and so should we not be allowed to commingle production of the Dakota with the Mancos, we would have to temporarily abandon the Dakota below some sort of a temporary plug. That production would be delayed until some point that the Mancos was depleted and we could go back to the Dakota and commingle it -- or not commingle it. We would have to complete it, abandon the

Mancos and then re-enter the Dakota.

So if we're not allowed to commingle the production, we're basically in a position that we'd have to postpone the production of Dakota reserves and that may never occur.

Q Mr. Roe, in your opinion will the commingling of production in the wellbore of this well result in the production of additional hydrocarbons, be in the best interest of conservation, the protection of correlative rights, and the prevention of waste?

A Yes, it will.

Q Were Exhibits One through Nine either prepared by you or at your direction and under your supervision?

A Yes, they were.

MR. ROBERTS: Move the admission of Exhibits One through Nine and we have no further questions.

MR. STAMETS: These exhibits will be admitted.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Roe, are any of the Dakota wells in this area gas wells?

A The testing that we've had to date would suggest that the Dakota is primarily oil in the wellbores that we've potentialed it.

Q Have you approached the District Office to see about establishing a Mancos-Dakota oil pool in this area?

A We -- that was addressed at the hearing that we had to establish the temporary pool rules for the Mancos. At the same hearing Northwest Pipeline basically made that proposal that a Mancos-Dakota Pool be established.

We are not opposed to that and we do see a need to have the two pools commingled. In our special pool rules we requested permission to have an administrative procedure to commingle both zones.

Now we did not support the establishing the single pool that would be commingled Mancos-Dakota. There were several reasons we didn't but we were in favor of having provision for administrative commingling and that was not addressed in the actual order that was issued.

In speaking with Mr. Chavez, he felt that the reason it wasn't necessary to address any special provisions for commingling, was that the State rules properly handled that, and this would be an example where the State rules don't properly handle it for administrative procedures.

We have the combined rate that exceeds that that's permissible under the State rules. That would be 50 barrels a day.

So I, dependent upon how the performance of the wells were early in the life, this is a fractured reservoir, I have a big concern that we're looking at some fairly steep declines early in the life once the well to well interference starts occurring and I feel reasonably certain that it will occur.

And so dependent upon how the future drilling looks, I think it would be our plan to come back to the Commission and ask for some provisions for administrative procedures. We did -- have previously submitted an application on this well for an administrative handling of this, which was denied. It's my understanding because of the rates between the two wells were too low.

Q What would your extra cost be if you had to set a bridge plug between the Mancos and Dakota at this time and produce the Mancos as a single until the rate declines substantially below 233 barrels a day?

A The extra cost probably would be in the range of, for setting the plug and going back and getting the plug out, I would say we'd be looking at $10-to-20,000 total.

Now, the problem that I would foresee in that would first off once the pressure had declined, in other words, we're on the verge of being outside the allowable pressure difference between the two zones, so at a point that we allowed additional pressure depletion in the Mancos to occur, there would be a greater pressure difference between the two zones. At that point we probably would not be able to use a conventional drilling to get the bridge plug out. We'd have to be careful what kind of a plug we put in there, because we would run the risk of doing damage to the Mancos trying to circulate and drill after some pressure depletion has occurred in the Mancos and we fracture stimulate the Mancos. I wouldn't expect that we could circulate, so anything we drilled up would be lost in the Mancos.

MR. STAMETS: Are there other questions of the witness? He may be excused.

Anything further in this case?

The case will be taken under advisement.

(Hearing concluded.)

CERTIFICATE

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

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 8041, heard by me on 2-15 1984.

Richard L. Stamets, Examiner
Oil Conservation Division