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

14 May 1986

EXAMINER HEARING

IN THE MATTER OF:

The disposition of cases on Docket 15-86 for which no testimony was presented.

CASE 8888, 8889, 8890, 8891, 8892, 8893.

BEFORE: David M. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:

Jeff Taylor
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

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28 May 1986

EXAMINER HEARING

IN THE MATTER OF:

Application of Northwest Pipeline Corporation for Hardship Gas Well Classification, Rio Arriba County, New Mexico.

CASE 8890

BEFORE: Michael E. Stogner, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:

Jeff Taylor
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For the Applicant:

Paul Cooter
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I N D E X

E X H I B I T S

MR. STOGNER: This hearing will come to order.

We will call next Case Number 8890.

MR. TAYLOR: The application of Northwest Pipeline Corporation for a hardship gas well classification, Rio Arriba County, New Mexico.

MR. STOGNER: Call for appearances.

MR. COOTER: Paul Cooter, with the Rodey Law Firm in Santa Fe, appearig on behalf of the applicant, Northwest Pipeline.

I have one witness, Paul Thompson.

MR. STOGNER: Are there any other appearances?

Will the witness please stand?

(Witness sworn.)

PAUL THOMPSON,

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

DIRECT EXAMINATION

BY MR. COOTER:

Q State your name for the record, please, sir.

A My name is Paul Thompson.

Q And by whom are you employed, Mr. Thompson?

A I'm employed by Northwest Pipeline Corporation in Farmington, New Mexico.

Q And what is your position with Northwest?

A I'm the Manager of Drilling and Production.

Q Will you relate for the record your education and professional experience?

A I received my Bachelor's of chemical engineering from New Mexico State in 1976.

I worked for Phillips Petroleum for three years in Bartlesville, Oklahoma.

I was hired by Northwest Pipeline in December of '79 as a drilling engineer; currently the Manager of Production and Drilling.

I'm a Registered Professional Engineer in New Mexico.

Q What does Northwest seek by its application in this case?

A We are requesting that a hardship classification be granted for the San Juan 29-5 Unit Well No. 91.

Q Exhibit Number One that has been marked for today's hearing is a copy of that application so filed?

A Yes, it is.

Q And your proration unit for the well is what?

A It's the east half of Section 35, Township 29 North, Range 5 West.

Q And what is the minimum rate requested by your application?

A We are requesting a minimum rate of 28 MCF a day.

Q Let me direct your attention to what has been marked as Exhibit Number Two. That is a narrative statement which I believe accompanied the application, did it not?

A That's correct.

Q Without going into all the details and we'll come back to this sometime later on, what leads you to believe that underground waste will occur if the well is shut in or production is curtailed?

A After periods of prolonged shut-in the well requires swabbing to return to production and the well's delivery potential decreases.

Our studies also indicate that irreversible formation damage has occurred resulting in the loss of recoverable reserves. We believe that this formation damage is an increase in the water saturation around the wellbore, which permanently decreases the formation's relatively -- relative permeability to gas.

Q Set that aside, if you would, and we'll come back to it in a minute, but let's go to Exhibit Number Three, which is the plat.

Would you locate the well for us in question?

A The 29-5 91 is located in the northeast quarter of Section 35.

Q Have you given notice of your application to the offsetting operators?

A The only offsetting operator is Meridian, who operates the 28-5 unit and yes, they have been notified.

Q Let me next direct your attention to what's been marked as Exhibit Number Four. What is that?

A Exhibit Four is a well history of the 29-

5 91.

The well was drilled and completed in July of 1980. During November of 1980 a 12-day liquid production test was completed on this well, which indicated that the well was making 19 barrels of water per day.

A stopcock was installed in May of '81 to try to control this water production to the 5-barrel a day limit. After experimenting with the stopcock setting a setting of two hours off and ten hours on was set in April of 1982. This stopcock setting appeared to maximize production while limiting the water production to five barrels a day or less.

The well continued to produce at this stopcock setting until September of 1984, at which time the well was shut in for over production.

In December of that same year, 1984, the well was scheduled to produce and we found the well logged. We equalized the casing and tubing pressures and were unable to return the well to production.

We spent considerable time in that next year soaping the well, equalizing the pressure, doing -- making every attempt we could to return the well to production without swabbing the well.

All those efforts proved ineffective and so in October of 1985 we moved a swab rig on this well and swabbed the well for five days.

Other offsetting wells have shown scale problems in the past, and so, because we weren't having much luck swabbing at this period, we decided to perform a foamed acid job on this well, which is a hydrochloric acid and nitrogen to try to remove any of these carbonate scales from the tubing, the perforations in the formation adjacent to the wellbore.

This was done and the well was swabbed again then from the 31st through November 2nd at which time we did have production fairly well to atmosphere and we attempted to put the well on line on November the 11th at a stopcock setting of five hours off and one hour on. The well logged in one day.

At the same time that we were swabbing on this 90 Well, we were working on the three offset wells, which, if I could refer back to Exhibit Three, the --

Q I think you mentioned the 90 Well, you're talking about the 91 Well?

A Yes.

Q Yeah.

A We also were swabbing the 30 -- or the 29-5 No. 90, which is located in the southwest quarter of this same Section 35, and we were also working on the 29-5 88 and the 29-5 38, which are directly to the west in Sec tion 34.

We were working on four wells with this one rig all at the same time and all four wells received acid jobs.

We swabbed the well again on the 20th of November last year, and put the well on line at a stopcock setting of seven ours off and one hour on, and the well produced to the line at that rate.

We experienced an estimated swabbing cost of $13,730, which does not include the cost of the acid job.

Q Now those costs are summarized on Exhibit Number Five, are they not?

A That's correct.

Q Proceed.

A At this point we realized that the well was going to be a problem to keep on line if it should be shut in again, so we notified the District office in Aztec and asked them to outline a logoff test procedure that we could follow to attempt to get the data for a hardship classification.

We initially started our logoff test on the 16th of December and concluded the test on the 26th and the rest, the results from this test were inconclusive.

We started a second logoff test, again after notifying the Commission in Aztec, on January 7th and we concluded this test on the 17th.

It was determined that a stopcock setting of eleven and three-quarters hours off and one-quarter hour on was not sufficient to unload the wellbore liquid. The well was open to the atmosphere and unloaded and this setting was reconfirmed with a third logoff test run between January 22nd and January 25th, with the same result.

Since that time we've experimented with several stopcock settings and the well appears to have stabilized a stopcock setting of seven hours off and one hour on at an average flow rate of 146 MCF per day and four and a half barrels of water per day.

Q Let's turn to Exhibit Number Six and ask you to identify and explain that.

A Exhibit Number Six is a graph showing the casing pressure versus time during our logoff test.

The way I understand, on a normal, flowing gas well when you run a logoff test, is you establish a stabilized production rate and then you slowly choke the well back to the point where you're below the critical velocity to lift wellbore liquids and you can monitor that effect by measuring the casing pressure.

This well is operated with a stopcock so the procedure is slightly different; however, this well does not have a downhole packer so there should be communication between the tubing-casing annulus and the tubing. So what we would expect is we would get a drop in the casing pressure whenever the well is turned on by the stopcock and producing up the tubing.

If the annulus and tubing communication is free, we would expect to get the same casing pressure drop for each flow period.

If the well becomes loaded with water or restricted, the communcation is restricted so that smaller and smaller pressure changes would be observed until at some point you'd open up the tubing and produce the volume of gas that's in the tubing and you wouldn't see any effect on the casing pressure at all.

At this point the well would be logged.

When you're running a test, what you try to do is to get an indication that the well was logging but try not to completely kill the well so you won't have to swab it back in.

It's obvious by looking at Exhibit Six that the casing pressure changes are becoming less and less through time so that the wellbore is loading up with liquids; therefore we concluded that a half hour per day flow time, which was two fifteen minute periods, was not sufficient to unload liquids from the wellbore and we have asked for a minimum of one hour per day production at approximately 28 MCF per day.

Q You received a temporary hardship classification that lasts until July 9, I believe, this year.

A That's correct. We filed an application for administrative approval in March and received our temporary classification till July 9th.

Q Let's turn to Exhibit Number Seven, if we may. That's the wellbore diagram for this well?

A That's correct. This a fairly typical well for a Dakota well in this area. We set 9-5/8ths surface pipe, 7-inch intermediate casing. We drilled the remaining of the hole with gas and set a 4-1/2 long string.

What should be noted here is that only ten feet, or the top zone of the Dakot sand was perforated and was completed with 50,000 pounds 4060 sand all in one treatment, so there would be no -- no attempt to try to squeeze off any water zone because the zone that's producing water is the same zone that's producing gas. There's only one zone open.

Q This well has produced water since its completion?

A That's correct.

Q Has that water production been reported?

A No, it has not. I -- we received an inquiry from Mr. Chavez about this and I contacted our Salt Lake City office who files the C-115s and asked them why no water production had been reported.

They told me that they had had discussions with Mr. Eppie Martinez several years ago and had advised them that the information that we were supplying to the BLM on our NTL 2-B's would be sufficient and that water production would not be necessary on the C-115.

Since I made the inquiry, the Salt Lake City office contacted Harold Garcia and he has requested that we start supplying this water production information. I understand that this information has been supplied retroactively to January of '85.

Q What has been the amount of water produced from this well in the past, on not a total cumulative but a total daily?

A Well, the reason we installed the stopcock back in May of 1980 was to try to control the water at a five barrel per day or less rate, which would bring us in under the NTL 2-B pit exemption so we could dispose of the water in an unlined pit.

Q To your knowledge has that been done?

A Yes, it has.

Q Turning back now to Exhibit Two for possible reference, explain the mechanical attempts that have been made to sustain production.

A Small bore tubing is -- has been and is being considered for this well; however, if the well is logged the tubing size is irrelevant.

Since a smaller amount of water can log the well in smaller ID tubing, then it's more difficult to swab in smaller tubing than 2-3/8ths. We're a little reluctant to set smaller ID tubing without some indication that the well will be on production full time.

We attempted two lift systems on the Wells 88 and 89, which are the two Dakota wells just to the west, and that operation was outlined in Exhibit Two, and those, both of those systems proved to be ineffective in lifting the water from the wells.

A pumping unit and downhole submersible pump were both rejected due to economics and engineering problems.

The well is operating under a stopcock to increase the bottom hole pressure and to decrease the water rate. It was initially installed to decrease the water rate; however, it's necessary now just to sustain production.

As I mentioned earlier, there is only one zone open so there's really no possibility for setting a retainer and squeezing off the water zone.

Q Turning back to the plat which is Exhibit Three, you've testified that Northwest is the operator of the Wells 88, 89 in Section 34, and No. 90 in the west half of Section 35 in addition to Well No. 91, which is the subject matter of this application.

A That's correct.

Q Are those wells on line?

A No, they're not. We have been unable to sustain production or to return wells to production after they've been shut in.

Q Let's go on, there are a series of graphs beginning with Exhibit Eight. Well, there are two of them, Exhibit Eight and Exhibit Nine. Explain those, if you would, sir.

A Exhibit Eight is the production graph for the 29-5 91. The units are MCF per month versus time.

What I'd like to point out is that in May of 1981 the stopcock was initially installed to help control the water production. The setting of ten hours on and two hours off was made at -- in April of 1982 and that was -- that caused the increase in production that you see in April of 1982.

From about that point the well declined at a 28 percent rate and was producing at about 7500 MCF per month when it was shut-in for overproduction.

Since we've returned this well back to the line it was only capable of producing approximately 4500 MCF per month.

Due to limited data that we have on this well after we returned it to production, I'd like to refer you to the next exhibit, Exhibit Nine, which is the production curve for the 29-5 No. 90, which is the offset well in the same section.

It's obvious by looking at this well that after an extended shut-in period between the middle of '82 and '83, that the production potential of this well was nearly as great as it was before it was shut in. As you can see, it was producing a little more than 10,000 MCF per month before the shut-in. It was only capable of producing 4000 MCF per month after the shut-in. After about a year and three-quarters it's obvious that -- that the well had stabilized at that rate.

Another thing to notice on both of these production curves is that after periods of shut-in you would expect to see an increase in production immediately after the well was turned on due to flush production. In both these cases the flush production is not evident.

Q All right, while we are comparing the 90 and 91 wells, let's turn next to Exhibits Ten and Eleven, if you would, and ask you to explain those.

A Exhibits Ten and Eleven are plots of the cumulative production of the well versus the square root of time. These plots are very helpful in demonstrating the damage wells have received, and/or the effects of production.

Now this is actually the same production data just displayed in a different format. It's just, you know, actual production taken from the chart, total depth, and then instead of just linear days, we've taken the square root of time. This is becoming a fairly popular method for measuring formation damage and flush production effects on low permeability gas wells of this type because it's been observed from hundreds of similar such wells that the slope of the cum production versus square root of time line for an undamaged well will be linear throughout its life until the well shows depletion, at which time then the slope rapidly decreases to zero or goes horizontal and that's the end of the well.

By observing the slopes on the 29-5 91, you can see the effect of the stopcock setting when the slope changed from Slope 1 of 13 to Slope 2 of 22.4, that that's the effect of the stopcock on the production; however, you can see that even after relatively short shut-in periods between Slopes 2 and 3 and between 3 and 4, that each time the well was shut in the slope decreases just a small amount, so that some formation damage is occurring.

Another thing that is normally observed on these kind of slopes is that after a well's been shut in for some period of time, when it's returned the slope usually increases temporarily due to flush production and then returns back to the original slope that it was before shut-in.

Nowhere on this graph is any indications of flush production evident.

With the limited data that we have, Slope 5, after an extended shut-in period is considerably less than it was before that time.

The same thing holds true, essentially, on the 29-5 No. 90, where we have longer flow periods. The reason that the slope is initially lower is probably due to formation damage caused by the frac job. What we're seeing there is just the well's cleaning up after frac and it stabilizes at that slope of 15.7, and then after an extended shut-in period the slope stabilized again at only 8.75, but since this slope has stabilized at this rate, it is a true indication of the well's actual production potential, and again, as with the 91, there is no indication that there's been any flush production and just another indication that damage has occurred.

Q Next let me direct your attention to Exhibit Twelve. What is Exhibit Twelve?

A Exhibit Twelve is our reserve calculations that we used to estimate the reserves that were lost due to the shut-in.

The reserves were calculated using an exponential or constant rate decline for the life of the well. It's been observed from most low permeability gas wells that the rate of decline increases after the well gets older, so an exponential, or constant rate decline tends to give conservative reserve estimates because the well doesn't deplete as fast as we would expect, and that's really why we use this type of analysis, to give us that conservative reserve lost estimate.

Northwest Pipeline actually uses a log fo the cumulative production versus a log of time for estimating reserves and we do not use the bottom hole pressure versus cum plots that are probably more prevalent in the literature; however, this well, based on or starting from its initial production until it was shut-in in 1984 averaged a 28 percent decline.

Using this 28 percent decline and the rate at which it was producing before it was shut-in, the remaining reserves were 319 MMCF.

Using the 146 MCF, which is the current stabilized production, the calculated remaining reserves are only 190 MMCF; therefore we can conclude that 129 MMCF have been lost in this well.

Based on the square root of time plots, we'd also expect that any further shut-in periods would tend to decrease this remaining reserves.

Q Is this well a Northwest Pipeline well?

A Northwest Pipeline operates this well on behalf of the 29-5 Unit operators.

Q In your opinion, Mr. Thompson, would the granting of this application and classification of the well as a hardship well within the parameters that you have suggested prevent economic waste?

A Yes.

Q Would the granting of this classification, of the hardship classification to this well might also encourage further expenditures for the adjacent wells that you've testified about, 88, 89, and 90?

A Possibly. We're a little reluctant with the current economics to spend much money on a well to have it shut-in shortly after we obtain production, so yes, if we were successful with this hardship case we might pursue it again on these other three wells.

Q And is the 28 MCF per day the minimum which in your opinion would be required to keep this well on line?

A That's correct. During our logoff test a one hour flow period per day did unload the wellbore liquid. Anything less than that did not.

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

A Yes, sir.

MR. COOTER: Mr. Stogner, we offer Exhibits One through Twelve and that concludes our direct presentation.

MR. STOGNER: Exhibits One through Twelve will be admitted into evidence.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Thompson, what -- I didn't catch that minimum flow rate which was needed to unload.

A Well, we based it on one hour flow period per day, which is approximately 28 MCF per day.

Q You alluded to a Federal rule N-2B? Would you elaborate on that?

A Well, that's NTL-2-B, which is Notice to Lessors. The 2-B requirements say -- it's concerning the disposal of produced water. You can apply for area-wide exemptions to the NTL-2-B if the wells produce less than five barrels of water per day, which we -- which we try to do.

Q And what does that mean to you all?

A That allows us to produce the water in an unlined pit on the location without having to build any disposal facilities or truck the water off.

Q Okay. Are you -- are you limited to how much water you can produce in there?

A Five barrels a day or less.

Q That's all you can produce?

A That's all.

Q And if you were able to produce more, what would you have to do?

A Then you'd have to make arrangements to dispose of the water in some commercial facility, like an injection well or evaporation pond, or I guess you could allow -- they'd allow you to build like lined evaporation pits on site.

Q Okay. So this well has been complying with this NTL-2-B.

A That's right.

Q On Exhibit Number Eleven, how does this water flow affect this particular example?

A We're looking at the cum production versus square root of time plot on the No. 90, is that correct?

Q It's your exhibit.

A Exhibit Eleven, is that --

Q Yes, uh-huh.

A Okay, and your question was what does the water have to do with it?

Q Yeah.

A Well, we're assuming that the water is probably the source of the damage that's being caused down-hole, that by increasing the water saturation around the wellbore we're losing the relative permeability of the gas and that is demonstrated by this change in slope.

The well is not as productive after the shut-in period as it was before that.

Q But you're artificially -- artificially restricting your water flow, aren't you, to keep (not clear-ly understood) with NTL-2-B?

A We can unload -- if the well was on, no, that's not true. The well was on and the wellbore was con-tinually being unloaded with the stopcock settings that we had before. Only when the well is shut in for an extended period of time do we see this damage.

The lines are linear; the points are linear there on Slope 1 and Slope 2, so --

Q But during those --

A -- there's no further damage being incurred while the well is on production; only after it's been shut-in.

Q But aren't you restricting your flow here to meet this five barrel a day limit?

A We were initially on the 91; that was never the case on the 90.

Q Oh, this -- this only makes five or less than five barrels of water per day.

A That's correct.

Q And you're not restricting that.

A Right. We installed a stopcock on the 90 Well almost right off the bat because you can tell that its production potential is not near as great as the No. 91.

Q And why did you put the stopcock on there?

A The bottom hole pressure, it takes time to get enough bottom hole pressure to lift the wellbore liquids. The permeability is so low in this well that it just, you know, if you left it on full time the critical velocity would drop below the point at which it could lift liquids and the well would log on its own.

Q Isn't that the opposite of what you're saying if you put smaller tubing in there?

A Actually smaller tubing so you can get the same -- you can get a higher velocity with the same volume of gas or you can reach that critical velocity with the lower volume of gas, so if you put in smaller tubing while the well is flowing then you could flow it at a smaller rate.

If the well is dead it doesn't make any difference. The well can't unload itself any easier with smaller ID tubing.

Q So Well No. 90 has been shut-in several times before and it's come back on, hasn't it?

A No, no, the No. 90 required swabbing again there around -- to get the well back on production around the square root of time of 32 days and we've been unable to regain production since it was shut-in there around the square root of time of 40.

Q Let me rephrase that.

In 1982 you were shut in for a long extended period and then in 1983 you came back on line, is that right?

A That's right.

Q So you were able to come back on.

A Yes, with swabbing the well.

Q Explain to me again why a plunger lift would not work.

A I can't tell you why it won't. It just didn't. We tried it on the two offset wells --

Q But you didn't try it on this one, is that right?

A Yes.

Q Thank you.

MR. STOGNER: I have no further questions of this witness.

Are there any other questions of Mr. Thompson?

If not, he may be excused.

Mr. Cooter, do you have anything further to add?

MR. COOTER: Nothing further to offer, Mr. Examiner.

MR. STOGNER: Thank you. Does anybody else have anything further in Case Number 8890?

If not, this case will be taken under advisement.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) 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. 8890, heard by me on 28 May 1986.

Michael E. Stogner, Examiner
Oil Conservation Division