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

18 February 1987

EXAMINER HEARING

IN THE MATTER OF:

Application of Conoco, Inc., for hard-hardship gas well classification, Eddy County, New Mexico.	CASE 9079, 9080, 9081

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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I N D E X

E X H I B I T S

EXHIBITS CONT'D

CASE 9080

CASE 9079

MR. CATANACH: Call next Case Number 9079.

MR. TAYLOR: The application of Conoco, Incorporated, for hardship gas well classification, Eddy County, New Mexico.

MR. CATANACH: Are there appearances in this case?

MR. KELLAHIN: If the Examiner please, I'm Tom Kellahin of Santa Fe, New Mexico, appearing on behalf of the applicant.

We'd request, Mr. Examiner, that you consolidate for hearing purposes Cases 9079, 9080, and 9081.

MR. CATANACH: Okay, at this time we'll call Cases 9080 and 9081.

MR. TAYLOR: Case 9080 is the application of Conoco, Incorporated, for a hardship gas well classification, Eddy County, New Mexico.

Case 9081, the application of Conoco, Incorporated, for hardship gas well classification, also in Eddy County, New Mexico.

MR. CATANACH: Are there any other appearances in these cases?

MR. KELLAHIN: Mr. Examiner, I

have one witness to be sworn.

MR. CATANACH: Will the witness please stand and be sworn?

(Witness sworn.)

MR. KELLAHIN: Mr. Examiner, I hand you our set of proposed exhibits for each of the three cases.

We would like to organize our presentation so that we discuss the Federal 34-2 Well first; then the Federal 34-1 Well second; and then lastly, the Levers Federal 1.

MR. CATANACH: Okay.

REBECCA BARNES,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Ms. Barnes, for the record would you please state your name and occupation?

A Rebecca Barnes. I'm a petroleum engineer with Conoco.

Q Have you testified before as a petroleum engineer before the Oil Conservation Division?

A No, I have not.

Q Would you describe for the Examiner when and where you obtained your degree?

A I have a Bachelor of Science in petroleum engineering from New Mexico Institute of Mining and Technology in Socorro, New Mexico.

Q In what year did you obtain that degree?

A May, 1986.

Q Subsequent to graduation have you been employed as a petroleum engineer?

A Yes, I have, with Conoco.

Q Would you describe for us what your general duties are for Conoco?

A Currently, right now, I'm working in our Acquisitions Group and also handling what we consider our Dagger Draw Area. We have a regular engineer in that area and I've been helping him out.

Q Where is the reservoir that's the subject matter of the three hardship well applications before the Examiner today?

A Where is --

Q Where is it located?

A It's located about fifteen miles north of

Carlsbad, New Mexico.

Q And this is in Eddy County?

A Yes, it is.

Q Has the reservoir been assigned a pool name?

A The reservoir is the Upper Pennsylvanian, or Upper Springs Gas Pool.

Q The docket describes it as the Spring-Upper Pennsylvanian Gas Pool in Eddy County, New Mexico?

A Yes, that's correct.

Q Pursuant to the application that Conoco has filed in each of those cases, have you made yourself aware of the requirements of the Division with regards to the filing of an application for a hardship gas well case?

A Yes, I have.

Q And did you prepare the exhibits and the proposed testimony for the presentation of each of those cases?

A Yes, I did.

MR. KELLAHIN: Mr. Examiner, we tender Ms. Barnes as an expert petroleum engineer.

MR. CATANACH: Ms. Barnes is considered qualified.

Q Ms. Barnes, let me direct your attention to the package of exhibits for Case 9081 for the Federal 34

No. 2 Well, and ask you to turn to Exhibit Number Two of that package on which we have the well located.

First of all, will you take a moment and identify for the Examiner what well is indicated by the red arrow on that exhibit?

A Okay. The red arrow indicates the Federal 34 No. 2 Well.

The area outlined in red ink is the proration unit for that well. The area outlined in the blue is the limits of the Federal 34 lease.

Q So the Examiner will know the location of the other two wells in relation to this well, would you also use this exhibit and find for us the location of the Levers Federal No. 1 Well?

A The Levers Federal No. 1 Well is located in Section 2, which is just south of Section 34. It's located in Unit E.

Q And where will we find the location of the Federal 34 No. 1 Well?

A It's located in the -- in Section 34, south of the No. 2 Well. It''s in Unit N.

Q Would you describe generally what caused you to conclude that these wells were eligible for a hardship gas priority classification?

A In 1986 we were shut-in for approximately five months out there. In the past it cost Conoco large sums of money to bring these wells back on, but due to the extensive shut-in this year, it was a lot more expensive.

The Federal 34 No. 2 Well, we spent $70,000 on, restored production temporarily and lost the well again due to the large amounts of water which accumulated.

Due to the extent of the circumstances and the pay out of the jobs to unload these wells is in excess of what we anticipated to be (unclear) might occur again. We would like to investigate the possibility of classifying these wells as hardship so we could continue to operate out there.

Q Were all three wells shut-in in 1986?

A Yes, they were shut-in the first of June and we were -- we began to bring them back the first of November, 1986.

Q When the wells were shut-in in June of '86, would you give us the approximate producing rates in terms of water production and gas production on a daily basis?

A Okay. The Levers Federal No. 1 averaged about 600 MCF per day and around 2400 to 2500 barrels of water per day.

The Federal 34 No. 1 makes about -- made aobut 400 to 450 MCF per day and approximately 1200 barrels of water per day.

The Federal 34 No. 2 averaged approximately 450 to 500 MCF per day and ranged from approximately 2000 to 2200 barrels of water per day.

Q Based upon your studies, Ms. Barnes, do you have a recommendation to the Examiner as to what the minimum producing rate is for each of the wells for which you would recommend the Examiner make approval of the wells?

A Yes, I do.

Q And what are those rates?

A For the Levers Federal No. 1 we seek a minimum sustainable rate of 350 MCF per day.

For Federal 34 No. 2 we seek 350, also.

And for the Federal 34 No. 1 we seek 300 MCF per day.

Q All right, using the package of exhibits for the Federal 34 No. 2 Well, would you turn now to Exhibit Number Three of that package and identify that exhibit?

A Okay. Exhibit Number Three is certified mail receipts of notification of the offset operators out there.

I will bring your attention to the certified receipt for NAPCO. The receipt was stamped for date of delivery but there was no signature. We sent a copy to two different addresses for them.

Q All right, let's turn to the wellbore schematic for the subject well and have you describe that exhibit.

A Okay. This is the wellbore schematic for the Federal 34 No. 2. It exhibits the casing, casing sizes and completion and also the tubing size which is in the hole.

The well was originally drilled to a depth of 10,388 feet and the Cisco formation was tested and perforated from 8,013 to 8,036 feet.

Currently we have 3-1/2 inch tubing in the hole, set with a packer at 7950.

Q The requirements of the hardship application require you to make an investigation to determine whether or not there is anything mechanical that you could do to the well to alleviate the volume of water produced and flowing into the wellbore.

Have you made such an investigation?

A Well, the water which is made is made from the producing interval, so we could not cut off or eliminate the water production without eliminating your gas and oil production; however, originally this well was run with 2-7/8ths inch tubing and we -- and to eliminate the effects of the large water, we ran 3-1/2 inch tubing to reduce the friction factors and allow us to be able to flow a larger quantity of water.

Q Is that true of each of the three wells?

A Yes, it is. They all originally were run with 2-7/8ths inch tubing and have since the original completion that has been replaced with 3-1/2 inch tubing.

Q And in your opinion, for each of those three wells, the 3-1/2 inch -- 3-1/2 inch tubing size is the optimum size to minimize the water problem and the friction involved in lifting this volume of water?

A Yes, it is. If you go with even a larger size tubing, you encounter the effects of increasing the diameter of the -- the column of fluid makes it heavier and then the well will not be able to flow. So there's an optimum region of friction factors and when your tubing size gets too large and the column is too heavy, so you need to find that optimum crossover where that occurs.

Q With regards to the perforations in each of the wells, do you have an opinion as to whether the perforations could be relocated in the wellbore at a point that would minimize the water flow?

A I have not investigated where the perforations are. All of the wells which have been perforated in the Cisco formation have all -- they've all produced large quantities of water.

Q All right, so it doesn't appear to be possible to simply isolate the water by perforating higher into the reservoir.

A No.

Q Is there anything else that you could think of that you might do to minimize or eliminate the volume of produced water?

A No, not out in this formation to eliminate the volume. The only way you could do that would be to try to isolate where the water was coming from, but the water is coming from the same zone as the oil and gas.

Q Let's turn to Exhibit Number Five and have you explain what this exhibit shows.

A Exhibit Number Five is a decline curve production history of the Federal 34 No. 2. This decline curve was generated on a computer which we have at Conoco.

The shut-in periods have been indicated on the decline curve. The majority of shut-ins you will exhibit a zero production. Some of the shut-ins were only for a short period of time or a partial month, so you can see a drop in production but not a zero production.

The -- well, I don't have colors on here -- I believe it's the red solid line is oil. The red/green line is oil. The red dashed line is gas, and the blue hatched line is the water production for the well.

Q Using Exhibit Number Five, would you show the Examiner the shut-in periods and identify for us, if you can, what impact those shut-ins have had on the subsequewnt ability of this well to restore itself to the original rates prior to the shut-in periods.

A Okay. Going back to 1984 a shut-in period was exhibited from about April through September of that year. Looking at the production after there, you can see that the first month the well is on the production has dropped and that is due to it usually takes a couple of weeks for the well to get back up to its original rate prior to shut-in; however, as you can see, the rate never quite recovers to the -- to the amount it was making before. This could be attributed to the shut-in or it could be attributed to just the normal decline of the well.

Going to 1985, we were shut-in twice out there. We were shut-in for approximately a month in the middle of the year and came on and the first month after that our production was lower due to giving the well time to recover.

The production came up and then we were shut-in again for approximately two to three weeks, just at about the time that the well was trying to recover.

That second shut-in in 1985 is shown by the dip in production. It's in about the month of Septem-

ber. As you can see, the well was slower to recover; each month it made a little bit more, and reached a rate that was somewhat similar to what it was making before it was shut-in, which still might be considered to normal decline.

In the shut-in in 1986 we were shut-in for an extended time, five months. We were notified by the gas company at the end of October that we could come on with these wells.

We did not get on location to the Federal 34 No. 2 till toward the end of the first week in November. We were on location for approximately three to four days jetting nitrogen continuously and got the well to flow on its own. The well flowed for approximately 13 days and then loaded up and died again and we have not done any more attempts to restore production in this well.

Q Would you describe the method Conoco has selected to attempt to restore production in each of the wells?

A Okay. In order to restore production you must lift the accumulated water which has encroached towards the wellbore. We use coiled copper tubing and nitrogen gas. Coiled tubing is run down the hole and nitrogen is injected at a rate of 350 to 450 cubic feet per minute. You will continue to inject nitrogen until you've unloaded enough of the water that the gas will be able to enter the

wellbore and begin to flow.

Q What is the approximate cost per well to attempt to lift the water production with the -- a nitrogen lift?

A It varies on each well. On this Federal 34 No. 2, in November when we restored production we spent $68,000.

Q Looking at the information from this well, do you have an opinion as to whether the decreased production is a permanent effect in this well?

A It's hard to determine in this well because the well was not on long enough to see if it was -- would stabilize.

In some of the other wells the recovery of the well has been so slow, particularly in the Levers Federal No. 1, that it appears that it will never come back up to the rate it was, but this well was not on long enough to determine that or not.

Q What do you believe is the cause in the decreased productivity of the well?

A When the wells are shut-in water encroaches towards the wellbore and this in turn decreases your relative amount of gas permeability at the wellbore. When the wells are brought back on, you must reduce this water saturation to allow the gas to come into the wellbore and flow.

With a large -- the amount of time that the wells were shut-in, the large amount of water encroached, and with the nitrogen job we tried to decrease saturation around that wellbore as much as we could, but in actuality what we did was just reduce it in the immediate area; when the well began to flow it came on at a rate real close to its minimum sustainable flowing rate and therefore the well kind of slugged (sic) along and in turn water satu-raiton continued to increase and again the well died after two or three days.

Q You've indicated for us the approximate cost for restoring production in the well. Can you now tell us the period of time it will take you to recover out of production the cost necessary to nitrogen lift the water?

A In this Federal 34 No. 2, basing the pay-out on the rate at which the well came back on, which is approximately 300 MCF, if the well would have continued to flow, the payout on that $68,000 would have been in excess of one year.

Q Apart from the economic impact of having to spend additional monies to restore production after shut-in periods, what are the other concerns that Conoco has about the water encroachment on the wellbores?

A Well, Conoco would like to continue to

operate in this area. Our main concern right now is the possibility if we get shut-in that we might permenantly lose the Levers Federal No. 1 and the Federal 34 No. 2 -- or No. 1.

On the Federal 34 No. 2 we're in the position where we can't justify any more work to bring back production unless we can be guaranteed a continual stream of revenue.

Conoco would not like to abandon this well but in our situation now and with the gas market, we can't justify spending more money since the payout is already in excess of one year.

Q Under normal operating procedures with the additional benefit of having a hardship gas well classification, can you project for us what the remaining life is of the well?

A Based on just the average decline of this well and declining from the rate which was before the shut-in, this well will reach the minimum sustainable flow in approximately two and a half years, on the Federal 34 No. 2.

Q In addition to estimating the economic life of the well have you also calculated the remaining recoverable gas reserves in the well in the event the hardship gas well classification is granted?

A Yes. Based on decline curve analysis

again, the estimated reserves for the Federal 34 No. 2 is approximately 350 or 360-million cubic feet of gas.

Q In the absence of a hardship gas well classification, to you have an opinion as to whether or not that is recoverable gas reserves that are going to be lost?

A In the Federal 34 No. 2, if hardship classification is not granted, Conoco will probably opt to abandon this well; so therefore the recoverable reserves will be lost.

Q For this well you have requested a minimum sustainable producing rate of 350 MCF a day?

A Yes, that's correct.

Q Would you explain to us upon what basis that you have reached that conclusion?

A Okay. We base this on a -- well, it's typical of the production history that we saw in 1986, and by using a Hagedorn-Brown pressure analysis for vertical gas flowing wells to anticipate necessary pressures and requirements to flow this well.

Exhibit Number Six or I believe it's Exhibit Number Seven, is a curve which is data which was generated from Hagedorn-Brown. Hagedorn-Brown is the most widely accepted calculations for vertical pressure losses in flowing wells. Hagedorn-Brown is usually used for wells which the primary production is a liquid and this -- in

these wells the primary production fluid is the water.

Basically the curve is just water production versus a pressure and what the pressure indicates is the pressure indicates the necessary reservoir energy to flow this well at certain conditions. Each water rate corresponds to a gas rate based on a constant GLR, which is exhibited in this well through history, which is 150.

The curve indicates, starting at your maximum water rate, it indicates that the required reservoir energy was at the highest due to the amount of water produced. The amount of water is your main constituent which affects your friction factor.

Q All right, let's make sure we're following how you're presenting the exhibit.

If I look in the upper righthand corner, I see the water production line at 6000 barrels a day?

A Yes, that's correct.

Q All right, if I commence looking at that line and I move down to the left, down the curve, tell me what happens.

A What's occurring is your water rate is decreasing; therefore the friction effect of the water as you bring it up through the tubing is diminished; therefore it does not take as much required energy to lift it.

As you come down the water decreases and

your friction factor decreases and your gas will lighten up the fluid and allow it to flow at a lower pressure.

As you come down and you reach the point at which the turnaround is, this point indicates that at that point your friction factor is no longer effective. At that rate your gas rate is so low that what you really have is a water well; you don't have enough gas to lighten that fluid, the column of fluid, to lift it, so therefore, in turn you start needing more energy again to lift that water.

This turnaround point, or the bottom point, is your minimum flowing rate. That would be your absolute. That's where -- that's the least amount of energy is required to ever flow this well.

Q The exhibit shows 150 and it says GLR, is that the --

A That's gas liquid ratio, 150. That will correlate looking at a certain water production, say, of 2000 barrels of water, that correlates a 300 MCF gas rate based on that GLR. Each water rate has a gas rate. These, you will see the bottom peak is at about 140 barrels of water per day, 100 -- and right around in there, which correlates, or it's -- it's actually 930. The hatched line there is 1000, and that correlates with approximately 140 MCF, but what you need to do is, you need to come up and look at this curve a little bit away from the peak.

Q All right, let me make sure, at the bottom of the trough just --

A Yes.

Q -- just a little less than 1000 barrels of water a day.

A Yes, it's about 930.

Q All right, at 930 convert that to me into an MCF of gas a day.

A That's 140; that would correlate to 140.

Q All right. Now, you have indicated that is the calculated absolute minimum rate.

A Correct.

Q In terms of the calculation, I asswme that you factor in some safety margin in order to have a rate at which you have eliminated the problem of having the well log off with water.

A Yes.

Q All right.

A As you move to the right you will notice as your curve, as the slope of the curve between your points is varying and it changes. If you look on Exhibit Seven-B I blew up that area which is in the square and you can see how -- how your slope and conduct of this curve is changing. What this means or what this is interpreted as is that the well is what Hagedorn-Brown calls bubble flow. Many people call it critical flow. What it actually interprets is that the well is not really flowing, it's more or less burping. It bubbles along with gas coming up and burping water, and you want to eliminate any of that type of situation because in a bubble or burp flow the well may continue to flow with that rate for a couple of days but what's happening is gas is burping up and it's leaving some liquid behind and the well is not really at a continuous flow.

If you look at your curve up at your higher water rate and your higher gas rate, you'll see that the line is pretty much a straight relationship. This indicates that it's in a somewhat continual flow.

So alleviating any of this bubble flow region you come up and your bubble flow region ends at approximately, oh, looking on the curve it's at about 1900 barrels of water, which correlates to about 280 or 300 MCF of gas.

So in other words, to eliminate bubble flow or critical flow, we need to have a rate that exceeds 300 MCF of gas; therefore to allow for a safety factor, Conoco has asked for 350 to eliminate the possibility of getting too close to that minimum rate.

Q Are you confident, Ms. Barnes, that the method by which you have calculated and determined the minimum sustained flowing rate for this well is one that's fair and reasonable?

A We, once we did the computer analysis of this and generated the data, we compared it to the production which occurred on this -- this Federal 34 No. 2 Well in November.

Exhibit, go back to Exhibit Six, is a record or just a reproduction of some of the daily production reports that well exhibited during that period after the nitrogen job and before it loaded up.

As you can see, the well originally came on at a rate of just a little over 300, which is real close to that critical bubble flow.

The well dropped to 270, continued to flow at that rate for about thirteen days but in actuality what the well was doing was kind of burping along and plugging along and the well was just slowly loading itself up, and then eventually died thirteen days afterwards.

Well, this correlates very well to the predictions of Hagedorn-Brown, which indicates that anything around below 300 you're going to be in that critical bubble flow and the possibility of loading up that well is very strong, and that correlates very well to what happened out there. So I feel secure that what we generated here is accurate data for the conditions in the reservoir that we have out there.

Q Do you have an opinion as to whether or not an actual log off test ought to be conducted on any of these wells?

A Well, the reason Conoco has not has been due to the fact that if we lose the well during the log off we're looking at having to spend anywhere from $40-to-70,000 to unload this well.

The other problem with a log off test is if you do not do an extensive log off test, if you did, say, a 24-hour log off test to see if the well would flow with that rate, if you had taken the Federal 34 No. 2 Well and cut it back to 270 MCF, that well probably would have flowed at that for a day but it was really not flowing. It's in that bubble flow.

A well may flow in a bubble or critical type flow for a week or two weeks, maybe only a day, so to do an accurate log off test it would have to be an extensive test to make sure that that rate is a permanent sustainable rate.

This well will probably, oh, you know, sustain a rate maybe of as low as 200 for a day, maybe, but it would not sustain that rate permanently, so therefore having to do a log off test, then you have to determine at what point is the well actually flowing or is it just burping in that bubble type flow, and unless you do an extensive log off test, you know, in a month, cutting back, letting the well flow at a certain rate for, say, two weeks, to make sure that well will continue to flow at that rate and not only temporarily.

Therefore it would be very hard, I think, to get an accurate log off test on these wells due to the fact that they really are not flowing gas wells, you know, they're really more of a liquid well because of the large extent of water that they make.

Q In your opinion is the Hagedorn-Brown calculation or correlation a more accurate method by which to set a minimum producing rate for these three wells?

A It is in this case. All that the Hagedorn-Brown correlation does, it calculates the pressure losses in your flow stream. Hagedorn-Brown is the most widely accepted correlation for which you would consider a liquid well; Gray is the most accepted for a gas well, but this is really not a gas well. You would want to correlate it more on liquid, and they have done, Hagedorn-Brown, they've done some modifications to this and the program which Conoco has, has incorporated those correlations.

Q And you have, as I understand your testimony, you have taken the Hagedorn-Brown calculation and you have matched or compared it to the producing reports on the Federal 34 No. 2 Well?

A That's correct.

Q The information available form the actual reports on that well closely matches the curve, then, for the Hagedorn-Brown calculation?

A Yes, it does.

Q Okay. Who is the gas purchaser for the gas from this well, do you know.

A Gas Company of New Mexico.

Q And is that true of the other wells?

A Yes, it is.

Q Has Gas Company of New Mexico been notified of the hardship application?

A Yes. They were sent copies of the emergency hardship classification that were obtained for these wells, plus the application for a hearing for the hardship gas well classification.

Q Do you have an opinion, Ms. Barnes, as to whether approval of this application would be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A Yes, I think it would be.

Q Let's go now to the exhibits for the next well, which is the -- I believe we were going to talk about the Federal 34 No. 1 Well?

A Yes, that's correct.

Q All right. Did you also prepare the exhibits and make the study for the information that's available to us on your proposed exhibits for the Federal 31 -- 34 No. 1 Well?

A Yes, I did.

Q All right. Let's turn to that exhibit package, which is labeled for Case 9080. Again let's look at Exhibit Number Two and have you locate the well for us.

A Okay. The Federal 34 No. 1 Well is located in Section 34, Township 20 South, Range 26 East, in Unit N, and is designated by the red arrow on this map.

Q And again have you sent certified mail receipt notification to the offset operators?

A Yes, we have. Exhibit Three is a copy of the certified mail receipts.

Q Exhibit Four is the schematic of the wellbore?

A Yes. This well was originally drilled to a depth of 10,595 feet. The Morrow, this well was originally drilled this deep to test the Morrow. The Morrow was tested and was perfed and was produced for approximately a year and a half or two years.

In 1981 the Morrow formation became uneconomical. The well was plugged back and perfed in the Cisco formation from 8,045 to 8,055 feet.

The completion on this well was similar to the Federal 34 No. 2. 3-1/2 inch tubing with a packer set at 7,905 feet, and the casing is similar.

Q Okay, and also you've adjusted the tubing size to be the optimum tubing size --

A Yes.

Q -- to lift this volume of water?

A Yes, 3-1/2 inch tubing.

Q All right. Let's turn now to the information shown on Exhibit Number Five and have you show the gas/liquid production versus time plot.

A Okay. This is the decline curve generated. The green solid line again is oil. The red dashed line is gas, and the blue hatched line is your water.

The shut-in periods have been noted again on this exhibit. I'm looking at the various shut-ins. You can see that this well has a tendency to recover to a rate equal to that prior to shut-in a little bit quicker than the other well has; however, if you look at the 1986 drop in production you can -- as you can see this was a lot lower drop and seems to not be along the lines of the normal decline of this well.

Q After repeated shut-ins, then, the latest shut-in periods have affected the well insofar as it is unable, apparently, to restore itself to the original producing rates?

A It was been extremely slow in restoring itself when compared to the other times; however, in this well it has over a period of, say, a month or a month and a half, it has exhibited characteristics that this well may return to a rate similar to it, but it is taking a longer time to do it than it has in the past.

Q What is the volume of -- what is the amount of money or the sum of money Conoco has spent with regards to restoring production in this well?

A In November, 1986, Conoco spent approximately $54,000 to restore production in this well, using the same method, the nitrogen gas and coiled tubing it has in the other well.

Q Is there a relationship in terms of the shut-in period that the well is shut-in, a relationship between the shut-in period and the effort you must expend to restore production --

A During --

Q -- in terms of time and money?

A During extended shut-ins it appears that it costs you a little bit more, need more nitrogen and of course you have to be on location longer. This is mainly due to it's more -- more water has encroached towards the wellbore and your water saturation has increased in a larger radius around the wellbore.

Then in the past, some of the short shut-ins we've had, a month or so, we've only spent, say, around $20,000 to unload these wells.

So it appears that the longer the extent of the shut-in, the harder it is to bring these wells back on production.

Q With a shut-in period of two weeks or less are you subject to having to expend money for the nitrogen lift?

A Yes. We had -- I believe it was back in 1984, '83, we had a compressor fail and we were shut-in. The well went down for only a couple of days and we still had to get nitrogen and coiled tubing.

Of course the cost of the nitrogen and coiled tubing was a lot less, but even for the short period it is still expensive to unload, but not as large, of course, as the extended shut-in.

Q Would you identify for us Exhibit Number Six?

A Exhibit Number Six is just a short record of some of the daily production reports for this well just to exhibit how slow the well has come back.

The well was at a rate of approximately 450 to 500 MCF per day before it was shut-in. Usually in the past this well would recover in about one to two weeks to a rate, but as you can see, it has taken almost two months, really, for it to slowly come back up to the rate similar to what it was making before shut-in.

Q Have you made a decline curve analysis of the production of this well to determine the remaining economic life for this well?

A Yes, approximately 2.1 to 2.3 years.

Q And what do you calculate to be the remaining recoverable gas reserves in the event a hardship gas well classification is approved?

A Approximately 250-million cubic feet of gas.

Q Have you also determined what you believe to be the minimum sustained flowing rate for the well?

A Yes, I have.

Q And what is that rate?

A The minimum sustainable flowing rate for this well is 300 MCF of gas per day.

Q And did you do a similar Hagedorn-Brown calculation --

A Yes, I did.

Q -- or analysis?

A Yes, I did. Exhibit Seven is again a graph interpretation of the data obtained from Hagedorn-Brown vertical pressure drops in a flowing well.

Again you've got reservoir energy or required pressures to flow the well at a certain rate on your Y axis.

Your X axis is water production. This water production correlates to a specific gas rate based on a gas/liquid ratio of 320. Through historical data that's what this well averages to exhibit. Just to give you an example, at 1000 barrels of water per day the gas rate would be 350 MCF per day.

Q The dashed line at 800 barrels a day?

A 800 barrels a day is approximately 250 MCF per day. That's the upper range of that bubble flow and that's the -- that's the flow that you want to avoid, so we have asked for 300 to allow for, you know, safety factors not to encroach too close to that 250 number.

This well will flow at a slightly lower rate than the other two wells because it only makes 1200 barrels of water per day; not the 2000 or 2500 a day.

Q Okay. let's turn to Exhibit Number Eight and have you identify that exhibit.

A Okay. Each of the wells I've included just a copy of the data obtained from the computer program. All this is is just a copy of the data that generated these curves, such water rate, and then the required reservoir pressure rate for each well.

I ran it for 100 to 800 in one case and then broke it down to get some intermediate points so that we could get an accurate graph in that critical range.

And Exhibit Nine is just a monthly production report. This is actually the amount of gas per month, not per day as the exhibit says, and this just exhibits -- gives you monthly gas rates and monthly water rates, monthly oil rate, and then a calculated gas/liquid ratio. This is a monthly average, just to exhibit where that 320 figure was obtained for the Hagedorn-Brown correlation.

Q Do your opinions about the Hagedorn-Brown calculation that you gave us on the 34 No. 2 Well, that it was the most effective method to calculate the minimum flow, do those same opinions apply to this well?

A Yes, they do.

Q Ms. Barnes, let's go to the last set of exhibits for Case 9079 --

A Okay.

Q -- and have you identify for us Exhibit Number Two concerning the Lever Federal No. 1 Well.

A Okay. Again this is a plat showing -- the blue outline indicates the Levers Federal lease, which is -- includes the entire Section 2, Township 21 South, Range 25 East.

The red outlined area shows the proration unit for the Levers Federal No. 1 and the arrow designates the well.

As you can see, these are not standard. This is not a standard section. It contains 912 acres and the proration unit is also nonstandard and it contains 296 acres.

Q Okay. And have you provided notice to the offset operators for this well?

A Yes, we have.

Q And that's Exhibit Number Three?

A Uh-huh.

Q All right.

A The certified notices.

Q All right, let's look at Exhibit Number Four.

A Okay. Number Four is a wellbore schematic of the Levers Federal No. 1. This well was drilled to a total depth of 10,362 feet. It was drilled to this depth to test the Upper Morrow formation. The well was tested in that formation and proved to be noncommercial. The well was plugged back to 9390 feet and was perforated in the Cisco formation. The perforations extend from 8,088 feet to 8,104 feet.

The completion of this well is similar to the others. It has 3-1/2 inch tubing and the packer is set at 7,805 feet.

Q As with the other two wells, in your opinion has Conoco done all it can reasonably and economically do to eliminate or prevent the water problem?

A Yes, it has.

Q Let's turn to the tabulation of production on Exhibit Number Five --

A Okay.

Q -- and have you describe that exhibit.

A Okay. Again this is a decline curve for the production history for the Levers Federal No. 1.

Again the oil is a solid green line; the gas is a solid -- or the dashed red line; and the water is the hatched blue line.

Again I've tried to designate the shut-in periods on this well. We experienced one shut-in in 1984, two in '85, and one in '86.

In looking at these shut-in periods, if you look at the production immediately after the shut-in you can see that it is a lower production, but the well was then increased to a rate which could be considered probably normal decline of the well.

However, if you look at the 1986 shut-in period, you look and you see that the well came on at a lower rate and recovered slightly but the rate is still well below the normal decline of this well.

Q As with the other wells, do you have an opinion as to whether the current decline in production is anticipated to be permanent?

A In this well, in the past the well has recovered -- or the drops in production have only been temporary; however, Exhibit Six, I have included some production reports extending two months past the shut-in and the well still has not recovered to a rate of approximately 600, which is what it was making before; therefore in this well I feel that it will never recover to the rate similar to what it was making before shut-in.

So I think the decline of production this time is permanent.

Q Have you made a calculation to determine the remaining economic life of the well if the hardship application is approved?

A This well will produce for a little over two years and calculated remaining reserves are approximately 418-million cubic feet of gas, and these were calculated off a decline curve analysis. declining it down to the minimum sustainable rate.

Q For this well what is your recommendation for the minimum sustainable producing rate?

A We would like -- we seek the minimum sustainable rate of 250 MCF per day.

Q Let me direct your attention to Exhibit Number Seven-A and have you identify that exhibit.

A Okay. Again this is a graph interpretation of the data obtained from Hagedorn-Brown's correlation of pressure drop in a vertical flowing well.

The Y axis represents the required reservoir energy or required pressure to flow this well at certain production rates. Again the water production rates correlate to a gas rate. This well exhibits a gas/liquid ratio of approximately 200; therefore, looking at a water production rate of 2000 barrels of water per day, this would correlate to approximately 400 MCF per day.

Again the -- starting at the top as you come down, as you make less water the friction factor and the pressure drops caused by the water decreases; therefore, the rate, the well will exhibit a lower rate when you get down to your peak, therefore your gas rate becomes so low that the primary function of how much pressure it takes is the fact that you don't have enough gas in a column to lighten it so that it will lift.

The area which -- which exhibits that bubble flow is indicated with a dashed line; however, looking at Exhibit Seven-B, which is a blow-up of that square area, this well, you will see that the inflection on the curve changes. It's a little more difficult to see in this well because the extent is not so great, but if you take a ruler or a straight line and lay it along that line you can really see that the inflection is changing.

Therefore, to avoid this bubble flow, we need to stay at a rate no less than 300, so we've asked for a minimum sustainable rate of 350 to allow for a safety factor.

Q On the chart where will that put you in terms of barrels of produced water a day?

A 350, it would be approximately 1750, so it will be between that hatched line and the 2000 hatched line, is where your 350 MCF of gas is.

Q 1750 --

A Barrels of water per day. 300 MCF correlates with 1500 barrels of water per day.

Q Okay.

A That's where that dashed line is coming down. That's the area we want to avoid. That's about critical bubble flow that you don't want to get well into.

Q The Exhibits Eight and Nine again are what?

A Exhibit Eight is a computer printout of the results from Conoco's Program GC-260, which is the well flowing analysis. These are the numbers which generated the curves that I presented.

And Exhibit Nine is just the monthly production and with a calculated average monthly GLR. That's just to indicate where the GLR factor came from that was used for the Hagedorn-Brown correlation.

Q Were Exhibits One through Nine in each of the three cases prepared by you or compiled under your direction and supervision?

A Yes, they were.

MR. KELLAHIN: That concludes our direct examination of Ms. Barnes.

We move the introduction of Exhibits One through Nine in Cases 9080, 9079, and 9081.

MR. CATANACH: Exhibits One through Nine in Case 9079 are hereby admitted.

Exhibits One through Nine in Case 9080 are admitted into evidence.

And Case -- Exhibits One through Nine in Case 9081 are admitted into evidence.

CROSS EXAMINATION

BY MR. CATANACH:

Q Ms. Barnes, do you know of any -- have you done any comparisons between your log off, actual log off tests and the type of equation that you used to determine this? Do you know how that correlates?

A I compared the results of the Federal 34 No. 2 log off, where the equations predicted it would log off, to the actual data that we had in November, 1986, and those correlated fairly well. It predicted that -- the equation predicted that anywhere between a range of 200 and 300 you were risking the possibility of losing that well to log off, and that well logged off at about 270 MCF.

That's the only actual log off test I have for those wells. We have never actually executed log off tests for any of those wells out there, due to the extreme amount of cost of bringing the wells back on.

Q Assuming that they died?

A Yes.

Q The wells aren't experiencing any formation damage, though, it's just the water encroachment that's occurring.

A From what I can tell, yes. It's just that by letting the water encroach toward the well you increase your water saturation at the wellbore which in turn decreases your relative permeability of gas; therefore you don't have that required amount of gas to, you know, around the wellbore to lift that amount of water.

I would like to add on the Federal 34 No.

1, the payout on that nitrogen job, the well is still producing. The payout on that job is six months; therefore as long as we're not curtailed before that six month perid we will pay out that job; however, with the current gas situation, there's a strong possibility we'll be shut in before we ever pay out that job.

Q Okay, let me see if I have this right. On the 34 No. 2 you spent $70,000, is that correct?

A Yes, approximately; it was actually $68,000.

Q That was for the shut-in period for 1986.

A Yeah, that was the restore production in November of 1986.

Q The 34 No. 1 Well you spent $54,000?

A Yeah, between $54 and $56, actually.

Q That was for that same shut-in period?

A Yes. We -- it was the first week in November we were restoring production.

Q How long was that well shut-in for?

A They were all shut-in for approximately five months.

Q Five months.

A Since the first of June, 1986.

Q Okay, on the last well you haven't had to spend any money --

A We -- it was shut-in in June with the rest and we spent $34,000 to restore production on that well.

We were not on location quite as long on that well. That well makes a little bit more gas; therefore it was easier to reduce the water saturation to such a rate that the well could flow on its own.

Q Okay, are you saying that if you had to, if the wells died again and you had to spend as much to repair them, you might not opt to repair them, or Conoco might not?

A Of course the Federal 34 No. 2 is shut-in. We will not do any additional work on it unless we can be assured of a continual generation of revenue.

The payout on the $68,000 job is already in excess of one year and you can't justify spending any more money unless you think you're going on for that.

The Federal 34 No. 1 with the payout on it being six months, if we're shut-in for an extended amount of time, we believe that it's going ot cost us $55,000 to lift it, we may opt not to bring it on if we don't think we're going to be on at least six months or for a year; therefore a hardship classification would help us out on the fact that we would know we would be on so we would be willing to spend the money if we knew we could bring the well back on, or if we brought it back on, you know, that we would pay out the job that we spent money on.

Of course the main concerns that we have on the Levers Federal No. 1 and the Federal 34 No. 1 is that we lose the wells altogether like we did No. 2, and we're afraid with another extended shut-in that they may exhibit characteristics similar to the No. 2 and it may be extremely difficult to bring them back on.

We would like to try to avoid losing those two wells as well.

Q So this is all due to economic reasons?

A Somewhat. Of course, the main concern Cononco has right now is losing the reserves in the Levers Federal No. 1 and the Federal 34 No. 1. If we're shut in again we may have the difficulty we did with No. 2, and may have to abandon those wells, you know, as we might the No. 2.

We're trying to avoid -- you know, in the past the wells have recovered, you know, fairly quickly, like in two weeks, but this time the Levers Federal didn't exhibit that recovery rate, and so we're afraid that if it gets shut-in again it may be more of a situation like the Federal 34 No. 2 and it may not recover at all.

The Federal 34-2 makes the least amount of gas and that is why I believe that that well died on us first before the other two.

We would like to avoid, you know, we would like to continue to operate out there and avoid having to abandon those wells before those reserves are recovered.

Q Are these the only three wells that you operate in that area?

A Yes. They are the only three wells that also produce from that pool in that formation.

We, well, we operate six to eight wells in the Dagger Draw area which is approximately -- must be about five miles from there, but that's in a different pool; that's in an oil pool.

Other than that those are the only wells that Conoco operates in the Carlsbad area.

Q This isn't a prorated gas pool, is it?

A No, it's not.

MR. CATANACH: I have no further questions of the witness.

She may be excused.

Is there anything further in Case 9079, 9080, or 9081?

If not, they 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 this portion 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. 9079, 80, 81 heard by me on February 18 1987.

David R. Catanach, Examiner
Oil Conservation Division