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

23 July 1986

EXAMINER HEARING

IN THE MATTER OF:

Application of Tenneco Oil Company for retroactive allowable, San Juan County, New Mexico. CASE 8944

BEFORE: Michael E. Stogner, 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

MR. STOGNER: Call next Case Number 8944.

MR. TAYLOR: The application of Tenneco Oil Company for retroactive allowable, San Juan County, New Mexico.

MR. STOGNER: Call for appearances.

MS. AUBREY: Karen Aubrey, with the Santa Fe law firm of Kellahin & Kellahin, representing the applicant.

MR. STOGNER: Are there any other appearances in this matter?

MR. CHAVEZ: Mr. Examiner, Frank Chavez, OCD Aztec Office.

I have a statement to make in opposition to the application, and if you wish, I could make that under oath as testimony with exhibits.

MR. STOGNER: Ms. Aubrey, do you have any objection?

MS. AUBREY: Mr. Examiner, we'd prefer to proceed with Mr. Chavez testifying under oath, if that's all right with you.

MR STOGNER: Okay, let's let the record show that Mr. Chavez was previously sworn in Case Number 8953 and the oath will still stand.

Are there any other appearances in this matter?

There being none, will Tenneco's witness stand and be sworn at this time?

(Witness sworn.)

MR. STOGNER: You may be seated.

Ms. Aubrey?

MS. AUBREY: Thank you.

JOEL FOX,

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

DIRECT EXAMINATION

BY MS. AUBREY:

Q Would you state your name and your place of employment for the record?

A My name is Joel Fox. I'm employed with Tenneco Oil in Denver, Colorado.

Q And what job duties do you perform for Tenneco Oil?

A I'm a project engineer, Production Engineering Group, with main responsibilities of production operations in the San Juan Basin.

Q Mr. Fox, in what area did you receive your professional degree?

A In petroleum engineering.

Q When was that?

A In 1977 and 1979.

Q What degrees do you hold in petroleum engineering?

A A BS and MS, both in petroleum engineering.

Q And what school did you go to?

A Louisiana Tech.

Q How long have you been employed as a petroleum engineer?

A Roughly seven and a half years.

Q How long have you been working for Tenneco Oil Company?

A Six and a half years.

Q Are you familiar with Tenneco's application that's going to be heard here today?

A Yes, I am.

Q And the subject well?

A Yes.

MS. AUBREY: Mr. Examiner, I tender Mr. Fox as an expert petroleum engineer.

MR. STOGNER: Mr. Fox is so qualified.

Q Mr. Fox, let me have you refer to Tenneco's Exhibit Number One and briefly recap for the examiner the events which have led to Tenneco's request today for a retroactive allowable for the "LS" Fields 2-A.

A The Fields "LS" 2-A is a well be obtained from the lease sale takeover which occurred in September, 1985.

Prior to the takeover in September, in May we looked at the field, though, as to a potential workover, adding Cliff House Menefee pay and stimulating that and also removing a tubing restriction from the well that we felt was restricting flow.

In August we sent in our appropriate sundries to the state and federal government for the workover.

September 5th we took over the lease sale properties from El Paso Natural Gas, of which the Fields "LS" 2-A was one well. It was making 1.6-million cubic feet a day and roughly 20 barrels of oil a day.

As soon as we took over operations, following that we ran pressure build-up survey to evaluate the restrictions of the tubing, of which I'll -- we have data on.

In September we pulled the 2-3/8ths tubing which was restricting flow and then we installed two separators on location. I might point out here when we took over the well it had no on-lease separation or oil storage on location. So we installed two separators and two 100-barrel tanks, and by pulling the pipe, 2-3/8ths inch and running an inch and a quarter of heat string to 2500 feet for chemical treatment, the rate went from 1.6 to 5-million a day and 700 barrels of oil a day.

And September 24th, one week later, we notified the -- El Paso and the Oil Commission we'd like to re-test the well for new deliverability.

Subsequent pressure differential indicated it was -- the well was still being choked by the 2-inch wellhead and also 1-1/4 inch heat string; also the oil rate was exceeding the volume. That could be handled by the two HLP 12-A separators, so we put a 4-inch wellhead, removed the 1-1/4-inch heat string, put two more HLP 12-A separators and two more 300-barrel tanks. The rate went to 9-million a day and 1100 barrels of oil a day.

In October we performed a deliverability test, which is shown there, 8.6-million and 700 barrels of oil a day.

Then we filed exception to Rule 107 to produce the well up the 4-1/2-inch casing and then in October, while waiting on two larger separators to be built and designed for the Fields 2-A, we replaced the 4 separators with 2 of these larger separators. We installed 4-inch flow lines to cut the restriction there; put a gas cooler to get the gas to pipeline specs; an electronic monitoring system -- safety shut-in and the rate showed 9-million a day and the well had dropped off to 500 barrels day.

And then in January we've got the integrated volumes from El Paso and filed the re-test, the new deliverability test, and then February 3rd, the proration unit was shut in overproduced.

Q Mr. Fox, from what formation does the well produce?

A The Point Lookout of the Mesaverde.

Q Do you have an opinion as to whether or not it's a typical Mesaverde well?

A No, it's not a typical Mesaverde. The reservoir character is so much greater exceeding those of the average Mesaverde in the San Juan Basin.

Q Have you made a study of particularly Tenneco's problems in the San Juan Basin to determine how many other wells you think there are in the basin that would display these kind of characteristics?

A In my opinion probably less than five or ten wells that exhibited this type of producing capability in the basin.

Q You said the well was now shut in because the proration unit was overproduced?

A Right.

Q Do you have any figures to show what effect a retroactive allowable would have on the overproduced status of the well?

A Yes. The problem when we did the re-test in October and then got the integrated volume to January, in January of '86, that time in between where they were waiting on the new test, the well was being produced at a high rate and subsequently got overproduced because it was producing with the old allowable of 1.5-million a day, and at the time waiting on the integrated volume from El Paso and just getting the paperwork, led to the well getting overproduced.

It's roughly, if you made it 90 days retroactive, it would account for about 290-million cubic feet of allowable would be removed from our overproduced state.

Q Tenneco has asked for a retroactive allowable effective November 1, 1985?

A Yes.

Q Can you explain to the examiner when the well would be allowed to come back on line if that retroactive allowable were granted as of that date?

A By our calculations, which could be in error based on the proration, we think sometime in August.

Q Do you currently have a market for the oil and gas which that well is producing?

A Yes, we do.

Q And who buys the gas?

A El Paso Natural Gas.

Q And who buys the oil?

A Conoco.

Q On Exhibit One, Mr. Fox, you indicate that Tenneco had intended to add the Cliff House in the Menefee pay to the well. Can you explain for the examiner why that was not done?

A Well, once we'd got the surprising rate, we -- we estimated the well would come on 4 or 5-million a day by pulling the tubing and it greatly exceeded that two-fold, and my supervisor indicated to me that I will not go back on that well and open additional pay until we watch this well stabilize, and the rate was enough for us to satisfy -- satisfy us.

Q Let me have you look now at Exhibit Number Two. That shows the surface equipment on the well at the -- or prior to the time that Tenneco took it over from El Paso?

A Yes.

Q What size wellhead is that that you're showing on Exhibit Number Two?

A It's a 2-inch wellhead. It accommodates 2-3/8ths tubing.

Q And with this surface equipment how much was the well producing at the time you took it over?

A Approximately 1.5 to 1.7-million a day and approximately 25 barrels of oil a day.

Q Let me have you look now at Exhibit Number Three. It's entitled Intermediate Surface Equipment Diagram.

Can you explain that for the examiner?

A While -- once we pulled the 2-3/8ths tubing in the oil rig, that was the big surprise on this well, was the increased oil rate. We had to install four separators. Each separator there shown is a typical Mesaverde single well separator.

We had to install four of those type to handle the oil volume and the gas volume on this well.

We changed -- well, the 2-inch wellhead remained as is and we installed the tanks and everything else remained the same.

Q Let me have you look now at Exhibit Number Four. Does this exhibit show the surface equipment as it presently exists?

A Yes, that's true.

Q And can you explain the differences in the surface equipment between Exhibit Number Three and Exhibit Number Four?

A The reason we went from the four separators to these two separators was two-fold.

There were no separators in the Farmington area that would handle this oil rate, oil volume, so they were being built by Weatherford-Olman Heath, that's a division of Weatherford.

The reason we went from the intermediate diagram to the current was the four separators, the small separators, had oil carry-over into our pits, and we could not handle the oil by (unclear) separators, so that's why we went to the two larger separators. It was a necessary step. It was an unexpected step but it was necessary to keep fluid carry-over with the four separators, so we put the two large separators, installed 4-inch line between the wellhead and the separators, changed out the well head to a 4-inch, 4-opening wellhead, installed a gas cooler to bring the gas to pipeline specs, and to recover any additional liquid, and I believe that was all the additional changes, and that's the current diagram, surface schematic.

Q Can you explain to the examiner why you changed out the 2-inch wellhead for a 4-inch wellhead?

A We ran a pressure differential and with the full 4-inch producing string the 2-inch wellhead was restricting flow. With this well's deliverability and flow performance the 2-inch wellhead restricted production.

Q And with this surface equipment what oil production were you getting?

A When we had all this piped in and turned on it was at roughly 1000 to 1100 barrels of oil a day. The GOR of the well was less than 10,000 at this time and that was the big surprise to Tenneco.

Q Let me have you look now at Exhibit Number Five which has three wellbore schematics.

A This roughly just shows our downhole changes we made.

The one on the left shows the well as it existed when we took it over from El Paso. 4-inch casing, 4-1/2-inch casing from the surface to the bottom, cemented to 3000 feet.

External casing packer above the Mesaverde.

The well is completed naturally behind a barefoot completion, we call it, the cement was not put behind the Mesaverde Point Lookout.

The well, then we pulled the 2-3/8ths tubing and run 1-1/4 in the middle schematic with the 2-inch wellhead still existing at this time and then on the right we pulled the 1-1/4 heat string we were going to use and then changed out the wellhead to 4-inch and did the other surface (inaudible).

Q So the schematic on the right of Exhibit Five shows the wellbore as it exists now.

A That's correct.

Q Let me have you look now at Exhibit Number Six, Mr. Fox, which contains a list of costs that Tenneco has expended in this wellbore. Would you explain those for the examiner and also while doing that, explain why you believe from an engineering point of view those costs were necessary?

A Roughly the cost, the main costs were the separators. We designed and built the wellhead and the other roustabout work and the 4-inch line, and also the safety shut-in monitors that were required on this well, since it was such a big producer. They're detailed there showing the cooler that we installed, separators, tanks, wellhead, et cetera. The roustabout work, mainly its high because we had to go back to the well and remove the four intermediate separators, installed the two larger separators. That was a move that wasn't expected. These costs probably are $10-to-20,000 higher than we wanted to spend, based on the fact that the high oil rate surprised Tenneco significantly and the total investment, I believe, is legitimate with the expenses involved.

Q I believe you testified that the larger separators were necessary because with the smaller separators you were still seeing oil in the pits.
A There was oil carryover in the smaller separators.
Q Has putting the larger separators on solved that problem?
A Yes, it has.
Q And with regard to the safty monitor, is that something that's necessary on every Mesaverde well?
A No, it's not. This is -- we install this on any well that we believe is -- has a prolific producing capability, such as Fields 2-A or on any well that we might, such as a townsite well, that if so, something broke in the line, whatever, and was uncontrolled, could create quite a spill over a short period of time.
Q And does this equipment automatically shut the well in --
A Yes, it --
Q --if there's a problem?
A -- does.
Q While we're still on Exhibit Number Six, Mr. Fox, can you compare these costs, the $158,964, to the cost of putting a compressor on the well?
A A compressor installation roughly would

require a D -- a DPC 360 of 360 horsepower, or Ajax, with roughly (unclear) marker. It would be about $185,000 investment.

Q In addition to costing $30,000 more, would the compressor require that you use hydrocarbons to run it?

A Yes, the compressor would roughly use 50 to 80 MCF for fuel.

Q Do you have an opinion as to what kind of increased production you would see by putting a compressor on the well, assuming that the tubing was not pulled and that the 2-inch wellhead was still on the surface?

A The 2-3/8ths is such a restriction that installing a compressor on the Fields to bring the pressure from 350 pounds flowing tubing pressure to 150 pounds flowing tubing pressure would increase the rate to about 2.6-million a day, is what we estimate.

Q And that's from the 1.5 to 1.7?

A Right.

Q Do you have a professional opinion, Mr. Fox, as to which procedure, either a compressor or the work that Tenneco did on the well, is more efficient in terms of dollars spent compared to increasing production?

A Well, by all means, if we can keep as much mechanical equipment off the location, such as a compressor, and also minimize fuel uses, it's going to bring more conservation of the energy and also less gas wasted for the state and for Tenneco and be more efficient system with that.

Q Let's look now at Exhibit Number Seven, which is a a multi-page exhibit.

Would you go through that for the examiner, Mr. Fox?

A This is basically our engineering back-up that we did starting in May before we took the well over and fine tuned it, once we got production rates from the well.

This Figure One shows just the effect of a compressor on the Fields 2-A as it originally existed. The dotted line on the pressure versus production graph is the in-flow performance of the Fields 2-A, or IPR, you might call it, pressure, bottom hole flowing pressure versus rate. The curves slanting up to the right are your 2-3/8ths tubing curves, the top one representing flow against line pressure of 300 pounds, 350 pounds.

The second curve simulates puttinga compressor on and reducing the wellhead pressure to 250 pounds, and the third curve represents drawing the wellhead pressure down to 150, and where the IPR intersects the tubing curves (unclear) solution and estimates the rate at those pressures -- you can see from curve A approximately 2-million a day rate should be achieved from the Fields 2-A against line pressure. It actually flowed 1.5, 1.7, and then with a compressor the rate goes to 2.6-million a day.

So again showing the restriction of the 2-3/8ths tubing.

Q So Figure One assumes the effect of the -- or shows the effect of the compressor with the 2-3/8ths tubing in the well.

A Right.

Q Would you go to Figure Two, please?

A Okay, Figure Two is really the main schematic showing -- has the in-flow performance of the Fields 2-A shown as the dotten curve 1. The average Mesaverde well is shown as -- also as a dotted line below that.

Curve A is the 2-3/8ths tubing curve and Curve B is flow representing the 4-1/2 tubing or casing and from the Fields 2-A intersection with Curve A shows the rate of 2-million a day before takeover, roughly, and by pulling that restriction out we go to 8.65-million per day with 4-1/2 casing, and roughly that's just based on a friction from Cuve A compared to Curve B.

The average Mesaverde well shown here is -- by removing the 2-3/8ths tubing the rate increase would be pretty negligible since it does not have the producing characteristics of the Fields 2-A.

I might point out here, this average Mesaverde well represents about 5 millidarcies permeability and the Fields 2-A here is matched with a permeability of 200 millidarcies.

So it shows the magnitude and difference between this well and your average well in the basin.

Q Does Figure 2 show, Mr. Fox, that if another operator were to perform the same work on -- that you have performed on -- on the Fields "LS" 2-A on the average Mesaverde well that he would not expect to see the dramatic increase in production?

A Yes. This, in my opinion and also shown here graphically, you have the inflow performance; also by pulling the tubing out of the well like that, if it makes any liquids at all, if it doesn't have a producing rate it would probably log off with fluids and the production rate would actually drop.

Q Have you had any problem with fluids in the Fields "LA" 2-A|

A No, we haven't.

Q Can you go to page three now?

A Page three is the actual measured bottom hole flowing pressure on the Fields 2-A with the 2-3/8ths tubing in the well as we took over. This was measured on September 6th; we took over the property September 5th;

showing the gradient on the left, upper left, is a flowing bottom hole pressure after four hours with the bombs on bottom, roughly 400 -- 595 pounds flowing bottom hole pressure.

The flowing tubing pressure was measured at 350 psig and the difference there being 245 pounds, would be the friction up thw 2-3/8ths tubing at that rate shown, 1.6-million a day and 20 barrels of oil a day.

Q And Figure 3.

A Figure 3 is another solution of the (unclear) analysis plot showing sensitivity of tubing diameter with gas rate for this particular well and as you increase the diameter going to the right the gas rate increases up to an optimum value somehwere around 7-inch casing would be a maximum or optimum for this particular well. It shows the effect of going from 2-3/8ths less than 2-million a day up to the 4-1/2 tubing or casing of 8-million a day, just based on friction alone.

Q Let me have you look at Exhibit Eight now.

A The production curve here is shown for the Fields "LS" 2-A. The well came on in the end of 1977 and then shown toward the end of the graph there is the before rate, roughly there, and that's on a log scale but I'll interpret that. That's about 1.7-million a day, cubic feet per day, and five barrels of oil a day in June, August of

'85, and then increasing rate shown there the first of '86.

The average daily rate for the well was 8.3-million per day, cubic feet per day.

Q And does Exhibit Number Eight show the oil production?

A Yes. Roughly the oil production averaged, after -- with that 8-million a day rate, was roughly 600-700 barrels of oil per day, monthly average.

Q What is the last full month that is shown on Exhibit Eight for production?

A The last full month shown would be January of '86, and that's roughly 8.1-million cubic feet per day; 240,000 MCF on this graph, and which equates to about 8.1-million per day and oil production 700 barrels per day.

Q And after that the well was shut-in because of overproduction?

A It was shut in February 3rd overproduced.

Q Mr. Fox, as a petroleum engineer, do you have an opinion as to what the term "workover" means?

A Well, with our company, anything, any time we have a rig on a well and change the downhole wellbore configuration of a well and also the substantial capital investment, we consider it a workover.

Even though the well is not stimulated, a stimulation is basically removing skin damage from a wellbore, which is actually back pressure, so you can equate skin damage, and also a restriction by 2-3/8ths is both back pressure, so using that as an analogy, it would be termed as a workover, based on reducing a substantial amount of back pressure against the formation, as would a reduced permeability zone around the wellbore would also.

Q Did the work that Tenneco performed on this well change the Kh factor in the well?

A No, it did not.

Q Do you have an opinion as to whether or not a change in the Kh factor should be the only criteria for determining whether or not the work performed was indeed a workover?

A Not in the case of a prolific well such as this, I do not. You can remove such a skin damage or skin fracture from a well mechanically versus stimulation-wise. I think it should be considered the same.

Q Would it have been possible for Tenneco, had it been aware of the Aztec Division's position in this matter, to acidize the well?

A Yes. If -- if we had known the feeling of the state, district, that this did not qualify as a workover, we would have, probably, I know for sure we would have acidized the well by either three barrels or two gallons down the tubing and got it classified as a workover.

As such we didn't -- we worked on a pretense (sic) from May of '85, four months prior to takeover, up to this day that it was a workover and that's why we weren't concerned with that definition.

Q Do you have an opinion as to whether or not acidizing the well would have increased the production from the well over and above what you've done to it?

A In my opinion the well, with that flat of IPR curve, I don't think you could have, because you can't have an IPR curve any flatter than that, really, so in my opinion, no, you would not.

Q Mr. Fox, were Exhibits One through Eight prepared either by you or under your direction?

A Yes, they were.

MS. AUBREY: Mr. Examiner, I offer Exhibits One through Eight.

MR. STOGNER: One through Eight will be admitted into evidence at this time.

MS. AUBREY: And I have no further questions at this time.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Fox, let's go back to Exhibit Number One here.

On August 27th you show that a sundry notice was sent. This being a federal well, I assume the sundry notice you meant was on the federal form, is that correct?

A Yes, it was.

Q When -- when does the BLM require a sundry notice?

A Whenever you change the downhole configuration of a well with the tubing or perforations, any stimulation, they require. Any surface change, they do not require a sundry notice; any downhole change they do require a sundry, and that sundry included our original proposal to add pay in the Mesaverde and Cliff House and Menefee members and also pull the tubing, so it was required.

Q Is a sundry notice required by the BLM if the tubing was just going to be changed out per se?

A No.

Q Say 2-3/8ths was going to be pulled and another string of 2-3/8ths installed?

A I don't believe so.

Q How about if 2-3/8ths was pulled and 2-

7/8ths was run?

A No, I don't think -- I don't think so.

Q Let's go to September 17th through the 19th. Please elaborate a little bit more on the 1-1/4 inch heat string.

A I did not mention but the oil produced from this area in the San Juan Basin is a high paraffinic (sic). It's a little lower gravity oil. It's actually oil, not condensate.

The 1-1/4 string was going to be used for treating paraffin that would form up the casing since we did not have a string of 2-3/8ths in there any longer to circulate chemical down, this was -- string was going to be used to either apply heat or a chemical to treat the paraffin, and, Michael, once we had the wellhead temperature up above the melting point of paraffin, we didn't have that problem we expected, so we pulled that string out. It wasn't needed.

And then that's also -- we installed the two extra separators and tanks.

Q Was a sundry notice required for this operation?

A No, it was not. We did have to file exception to Rule 107, a tubingless completion, to the state.

Q Do you remember the order number?

A No, I don't. All I know, it's Rule 107, exception to Rule 107 in the state rules and regulations requiring all gas wells have adequate tubing in the wellbore.

Q Was that submitted for administrative approval here in Santa Fe?

A Yes, it is shown there in October 15 when we sent it to the Oil Conservation Division.

Q So we should have that on file here in Santa Fe.

A Yes.

Q I'll take administrative notice of that. Could you tell me when the next sundry notice was sent to BLM after August 27th and for what reason was it sent, or was one sent?

A That was October 15th, the exception.

Q And was a sundry notice sent to the BLM?

A No, I believe it was just sent to the Oil Conservation Division for that exception.

Q Okay.

A The BLM wasn't involved.

Q All right.

A The September 24th was our request for a re-test sent to the District Office of the Oil Conservation Commission and El Paso, the transporter.

Q I'm just talking about sundry notice to the BLM now. Has one subsequently been filed after that September -- I mean after the August 27th filing?

A I believe it has, Mike. Are you pertaining to the tubing or --

Q For any reason was sundry notice sent to the BLM?

A Yes, that's right. All the work activity downhole, especially, was followed up with sundry notice detailing all work activity as it occurred on the well.

Q Okay. So let's back up to that September 17th and 19th. A sundry notice was sent to the BLM reporting that work.

A Yes, it was.

Q Okay. I'm going to take administrative notice of the well file here in our office on that.

Is the BLM, are they notified that this well is or was producing through the casing?

A I'm not sure.

Q Let's go to Exhibit Number Six, and this is workover and equipment cost. Let's just talk about the workover costs. What are those?

A Mainly the rig work shown there of $14,000, just the rig cost for pulling the -- changing out the wellhead.

To change out the wellhead we had to set a bridge plug above the perforations to isolate any pressure from the -- while we worked at the surface, you know, moving the wellhead and changing the tubing out.

That roughly covers that cost.

Q And the equipment cost is -- is shown under surface equipment --

A Right.

Q -- is that correct?

A That's correct.

Q And the intangibles, that would be considered equipment cost, too?

A The intangibles would be roustabout labor, materials to hook up the separators and tanks, and also build the pits, line those pits, fence those pits, excuse me.

Q Now let's go back up here and talk about this $14,379 rig work. What would you consider out of that cost as actual workover?

A 100 percent of that cost.

Q You would consider changing out the wellhead as workover, or Tenneco would consider that as workover?

A Yes, because you do have to do downhole work to the well by installing bridge plugs, and what have you, to keep the Mesaverde from coming in on you while you're working on the wellhead, so you would have to have a rig on the well to do that, and any time we rig up on a well, then in that sense it's a workover.

The other surface cost of separators and tanks, I might point out, this lease had nothing but a well-head and a pit, a fenced pit on location when we took over, so we had installed tanks, separation equipment as part of this work.

Q Okay. Now, in your testimony previously you mentioned something, the term workover as being when downhole configuration is changed, so we can essentially eliminate the surface equipment as your term as workover, is that correct?

A Well, it would have to be related to the workover such that as part of the downhole configuration change the surface equipment was required to handle that fluid and gas volumes.

So I guess it isn't strict -- if workover was defined as only improvement in cage or downhole change, then that cost would not be workover cost. That would be surface equipment installation, but there is no such definition.

Q But it, the surface equipment was moved in because of your downhole configuration work.

A Right.

Q Does the BLM require a sundry notice if you change out the wellhead equipment?

A I don't believe so, only the Conservation Commission, we make our sundries.

Q I'm sorry?

A I believe not the wellhead, no, just downhole, tubulars, and what have you. We can change any valve on the wellhead or what have you without the government approval.

Q Okay. So how does Tenneco's term workover and BLM's term of workover to require a sundry notice, how do they differ?

A I'm not sure I understand the question.

Q What is the minimum you have to do before you have to file a sundry notice to BLM?

A I believe any downhole change, subsurface. I believe that's right, Michael.

Q And according to Exhibit Number Six, your term as workover, Tenneco's term as workover is when you move the rig on the location, is that correct?

A Right.

Q Let's review one more time Exhibit Number Five.

When was the downhole configuration changed in this exhibit? And how was it changed?

A In the middle schematic, September 17th when we pulled the 2-3/8ths, 17th through the 19th, installed 1-1/4 inch.

And then in October of '85 we went to the third shematic on the right, pulled the work string, or the inch and a quarter string and produced it solely up the 4-1/2 casing.

Q Okay, and both times a sundry notice was required by the BLM.

A Yes.

Q Okay.

MR. STOGNER: I have no further questions of Mr. Fox at this time.

Mr. Chavez, do you have any questions?

Is there any other questions of this witness?

Ms. Aubrey, do you have any questions?

MS. AUBREY: No, sir.

MR. STOGNER: A few more questions, then, concerning the retroactive. Tenneco wants this retroactive to November 1st, 1985, is that correct?

A Yes.

Q This is under the terms of the proration schedule for the Blanco Mesaverde Pool?

A Right.

MR. STOGNER: Are there any other questions of this witness?

If not, he may be excused.

I believe at this time, Mr. Chavez, you had a statement, and Ms. Aubrey, I will let you follow that with a closing statement.

MR. CHAVEZ: Mr. Examiner, I'm Frank Chavez, Supervisor of the Aztec District Office of the Oil Conservation Division.

The question here seems to one of defining a workover for the purposes of assigning a retroactive allowable under the deliverability test rules for the San Juan Basin, not necessarily defining workover for all purposes.

Under the policies of the Aztec Office we have been accepting downhole work on a well to be a change to the Kh of a well. We have been using our criteria for this, the gas laws and rules that are summarized and explained in the introduction to the back pressure test manual for the State of New Mexico, which I have shown as Exhibit One before you.

On page I-2 of that exhibit is the equation I-1, which is the radial flow equation for gas flow in a symmetrical reservoir. It's quite a complicated equation but in the paragraph below the nomenclature explanation on that page is explained how the different terms can be summarized to a single constant so that only the pressure differences will be shown at making an in Q.

We consider this to be the basis for testing deliverability and gas in the San Juan Basin.

On the second page of that introduction is -- on the first paragraph on this -- I'm sorry, the first paragraph of the third page, page I-3, there's a discussion about that cost in C. The last sentence ends in, and I'll quote:

Later studies indicate that for wells producing from low permeability reservoirs the coefficient C is a variable related to time and can be considered constant only with respect to the particular time.

In order to all for that we request deliverability tests, or require deliverability tests, every other year. That accounts for the changes in bottom hole pressure due to production from the wells and the changes in Q.

On page I-6 of that introduction is the equation I-3, which is a deliverability equation that's used to calculate deliverability for wells in the San

Juan Basin.

In using this equation, as long as the constant is not changed for that well, there will be no change in D, in deliverability, because Q would change in relationship to the flowing wellhead pressures based on the back pressure curve for a particular well.

Consequently, changes in restrictions in the wellstream, in the flow stream, theoretically would not make a change in D.

Basically, to put it simply, if you were to reduce the back pressure on a well, you'll naturally produce more gas. If you increase the back pressure on a well, you'll naturally produce less gas.

This is what these equations say.

For the purposes of assigning allowables to wells, we have been using the idea that when a new well comes on the line it is identified by its deliverability as concerns it's productivity; the deliverability in a sense describes the reserves attributable to that well, and that's one reason that it is used in the calculation of the allowable.

When a well is worked over, such that Kh would be changed, say new perforations are added, or other work changes that changes the Kh on the well. We consider that that would be a new well, a new identity, a new productivity. It would have new reserves, and therefore under the deliverability rules we allow that well to have retroactive allowable assignment to the day of first production after this workover or ninety days previous to the date we receive the deliverability test, as we do a new well.

In cases where there has been a change in Q due to some other work which may indicate that the previous deliverability test was not correct because of Q, we would assign a new allowable based on the new Q at the first day of the month following a month we received a test.

On the Fields 2-A we took this latter course because there was no work done on the well which increased the Kh. The work that was done on September 17th and into the 19th on this well increased the productivity of the well at that time. That was a change in the downhole tubing configuration and installation of some separators.

There was also another change made in the first week of October.

There was also a change made the last week of October, but the change made in the last week of October increased production, however, did not involve any downhole work; only the elimination of restriction at the surface.

So the elimination of a restriction in the flow stream, in the mechanical flow stream of the well, we consider to not be a workover.

One alternative which was not taken for the purpose of testing this well, was producing through both tubing and the tubing casing annulus at the same time. That would have had the same effect as reducing the back pressure on the well and would not have involved any rig time.

The equipment that has been put on the well is designed to handle the entire flow stream from the well; however, in the foreseeable future the allowable of the well will be such that during production it will meet its allowable within just the first few days of the month. Therefore the equipment sizing and the money expended for that may or may not have been necessary in that the allowable can be produced with the well choked back over a longer period of time and not required such large sized equipment.

If we were to call the elimination of these restrictions in the flow stream workovers we would be placed in the dilemma to decide at what point do we call a certain activity on the well a workover.

If just the wellhead had been

changed out would that have been called a workover.

If the separation equipment, larger separation equipment been installed, would we call that a workover.

This type of dilemma I think is something that we can do without when we're trying to assign allowables and account for deliverability.

That's all that I have.

MR. STOGNER: Thank you, Mr. Chavez.

Ms. Aubrey?

MS. AUBREY: Thank you, Mr. Stogner.

Mr. Chavez, is the Aztec District's position on what is a workover written down any place?

MR. CHAVEZ: No, we addressed it in the Deliverability Test Committee that met and there was a consensus reached in that committee that a workover had to be work done on the well, because I brought this dilemma up.

MS. AUBREY: Wasn't the consensus of that committee also that placing a compressor on the well also qualified the well for a retroactive allowable?

MR. CHAVEZ: It did in the

sense that there are many wells at this time that could not produce against the line pressure and if a compressor is installed to produce a well that would not otherwise produce at all, we could do that in the sense that we had no Q to work from; you actually did not have a well.

MS. AUBREY: Does placing a compressor on a well change the Kh value?

MR. CHAVEZ: No, it doesn't.

MS. AUBREY: But the Aztec Office now treats or has treated putting a compressor on the well as work which qualifies for a ninety day retroactive allowable.

MR. CHAVEZ: Yes. It was the consensus of the deliverability committee that we do that.

MS. AUBREY: And is that rule written down anywhere?

MR. CHAVEZ: No, it's not.

MS. AUBREY: Is the term workover defined in the rules and regulations of the New Mexico Oil Conservation Division?

MR. CHAVEZ: No, it is not.

MS. AUBREY: Has that committee report been published any place that an operator could get it and read it?

MR. CHAVEZ: As such I don't

think so, but I know that Tenneco did participate in all the Committee meetings.

MS. AUBREY: So if Tenneco had put a compressor on this well, notwithstanding the fact that the production would not be proportionately increased in relationship to the money spent, the Aztec Office would not oppose the retroactive allowable for the well.

MR. CHAVEZ: It's possible. This would have to be discussed because of, again, we're looking at the idea that a well was not producing into the pipeline at first.

MS. AUBREY: Are there wells in the San Juan Basin for which you have approved a retroactive allowable that were on production after -- before the installation of a compressor?

MR. CHAVEZ: I think so.

MS. AUBREY: So being not -- being shut in or not producing at all is not the criteria.

MR. CHAVEZ: Not always, no.

MS. AUBREY: Are the criteria written down any place?

MR. CHAVEZ: No, they are not because each case is -- should be considered on its own.

MS. AUBREY: If Tenneco had acidized this well nothwithstanding that acidizing the well would not change the production over and above what Tenneco's done to the well, would the Aztec Office approved a retroactive allowable?

MR. CHAVEZ: Probably, if the acidizing was done as part of any workover we expect that there's some improvement in production. It's to be done for that purpose.

MS. AUBREY: You talked a few minutes ago about your concern over having changes in surface equipment alone be considered to be a workover.

Do you have a problem with changing the downhole configuration of the well qualifying as a workover?

MR. CHAVEZ: Yes, I do.

MS. AUBREY: Okay. Would you tell us what that is?

MR. CHAVEZ: The same problem I have with the surface equipment in that it is just done to remove a restriction.

We can consider that as a restriction in the mechanical flow stream. We can -- the flow stream is a tubing in the well, the wellhead, the surface, other surface equipment, to the meter box, and any change in that are just changes in the flow channel.

MS. AUBREY: Doesn't a compressor make the same kind of changes, though?

MR. CHAVEZ: Not necessarily.

MS. AUBREY: It doesn't change the permeability of the well?

MR. CHAVEZ: No, it doesn't.

MS. AUBREY: Does not affect the Kh character of the well?

MR. CHAVEZ: No, it doesn't.

MS. AUBREY: It doesn't change the porosity of the well.

MR. CHAVEZ: No, what the compressor would generally do is -- this is why each case is considered, is that it would allow removal of fluids that were restricting the production. If the well was loading and the compressor was required to increase the gas rate such that the velocity of the gas would carry the liquids, then we've got the change in productivity attributable to something that showed the well was not producing at its best to begin with.

MS. AUBREY: With no change in the downhole configuration of the well.

MR. CHAVEZ: At that time (unclear.)

MS. AUBREY: I believe you testified that when a well -- when work is performed on a well that the Aztec Office considers to be a workover, that you consider that a new well which is producing new reserves?

MR. CHAVEZ: If you add perforations to a well, yes.

If you do some acidizing that opened up perfs that were otherwise closed and you couldn't produce reserves because of that, yes, and under the deliverability rules this is -- what we try to do is adjust the allowables to the reserves on the basis of deliverability.

MS. AUBREY: Is it your opinion also that if one puts a compressor on a well that one has been producing new reserves?

MR. CHAVEZ: Not necessarily. If the well has been loading with liquids such that the previous deliverability was not adequate to indicate those reserves, yes, we consider it a (unclear).

MS. AUBREY: I have no more questions, Mr. Stogner.

MR. STOGNER: Thank you, Ms. Aubrey.

Mr. Chavez, some of the wells up there load up with water and a pump, a pumping unit is then placed on the well. Is that considered workover in the Blanco Mesaverde or Basin Dakota?

MR. CHAVEZ: If the well been loaded, yes, that -- such that it couldn't produce at all, yes, that's considered workover in the sense that the previous deliverability test was not adequate to describe the reserves.

MR. STOGNER: And so if this was a remedial type -- this -- that analogy would be a remedial type of a workover to remove the water per se?

MR. CHAVEZ: Yes, it's the same situation that occurs if you would install a compressor on the wellhead that was -- it couldn't produce against the line pressure because the line pressure was higher than the shut in.

You had no cue as a basis to say that well had reserves.

MR. STOGNER: As you understand it why was the 1-1/4 heat string run into the well in September?

MR. CHAVEZ: I think there was -- my understanding was that there was concern that the lowered temperaturs up hole would cause paraffin to form in the casing and it would be very difficult to clean out and be quite a problem if that occurred.

So the -- my understanding is that that string was installed in order to pump heat back down into the wellbore.

MR. STOGNER: Would this be considered some sort of a remedial work to eliminate the paraffin problem?

MR. CHAVEZ Well, I don't -- I think it was preventive work that apparently found -- they found was not necessary.

MR. STOGNER: So the whole thing comes down to changing the 2-3/8ths inch tubing to 4-1/2 inch casing as being considered the workover in your opinion?

MR. CHAVEZ: Yes. And again, I want to try to limit the workover definition for purposes of assigning allowables based on deliverability. It may not apply for other activities or requirements from this office or the BLM under normal usage of the term workover.

MR. STOGNER: When was this policy for deliverability purposes of changing relief -- that the Kh factor be changed, when was that initiated and how long has that been in effect?

MR. CHAVEZ: I don't know. I came to work for the Commission in '78 and at that time, actually, workovers had a little broader definition, but after discussion with deliverability test committees we determined -- not just with deliverability test committees but with operators out of the committee, we determined that that wasn't adequate for any surface work to be included in the deliverability -- or, I'm sorry, to be included as workover, or -- and it was further, I guess you'd say solidified, with the deliverability test committee meetings that went on the last few years.

MR. STOGNER: Okay, when did the deliverability committees start meeting, approximately?

MR. CHAVEZ: 1983, I'll say. I don't know for sure.

MR. STOGNER: Okay, let's say '83.

MR. CHAVEZ: It's been at least three years.

MR. STOGNER: Okay, so the policy was being instituted at that time.

MR. CHAVEZ: Well, actually, even before then, but at that time it was solidified because we were having problems with the allowable assignments based on a deliverability test; could be sent to us for any reason and called either a re-test or test after workover, and there were some instances where I rejected a test when an operator called it a workover when actually they had -- they had done nothing to the well except that the line pressure had fallen and therefore they were able to produce more gas and it will get a higher cum. Those tests are rejected as workovers.

MR. STOGNER: Would this have been considered a workover prior to '78 -- prior to 1978, and the policies that were instituted at that time?

MR. CHAVEZ: At that time I don't know. I can't presume what Mr. Kendrick would have done at that time.

MR. STOGNER: How about between '78 and '83?

MR. CHAVEZ: Probably not.

MR. STOGNER: I have no further questions of Mr. Chavez.

Are there any other questions?

MS. AUBREY: May I ask two or three questions?

Oh, go ahead, Mr. Stamets.

MR. STAMETS: I'll just -- I'll be brief.

Mr. Chavez, what bad result would you see flowing from -- for purposes of these rules, declaring this type of operation where tubing has been -- or there has been some downhole work, declaring that to be a workover? Do you see any other problems resulting from that?

MR. CHAVEZ: Yes, I do, in a sense.

The restrictions that can be removed, you know, speaking hypothetically, I think we can -- we can use our imagination to find that there are a lot of things that have come out as workovers in that sense.

Mr. Fox requested that the installation of equipment a the surface be part of the workover because it was required because of the size of the increasing production from the well.

I don't like as an administrator many times to have these definitions too broadly done and therefore my discretion to be too broad an area so that there can be problems that come up. If we start saying this is a workover, I have a feeling that there will be a lot of other minor activities be considered a workover. A swabbing run, one swabbing run on a well could be considered a workover whether it is necessary or not for the purposes of getting higher deliverability.

We can go on with that but I see problems developing if we say that this is a workover.

MR. STAMETS: And I'd like to suggest that the examiner might want to at least look at the definitions of workover an re-work in Williams and Meyers Definitions of Oil and Gas Terms.

Those are the only points I have, Mr. Examiner.

MR. STOGNER: Thank you, Mr Stamets.

Ms. Aubrey.

MS. AUBREY: Thank you. Mr. Chavez, do you have an opinion as to whether the previous deliverability tests, and I mean the tests before Tenneco took this well over in 1985, adequately described the reserves?

MR. CHAVEZ: No, they don't in -- in this sense. Mr. Fox himself stated there are five to ten wells in the San Juan Basin that exhibit particular producing characteristics and the reason is because they have either some natural fracturing or other associated reservoir conditions that do not match the conditions that we put on them in our deliverability test rules, especially the slope. A slope of .75 is forced on these wells.

My recommendation in a situation like this where a well does not need that, is not that we go through this procedure of trying to twist our words and call this a workover, but that a provision be made to get a pool slope for that well that describes that well better than what we have. The way Mr. Fox described it, he could actually drill a replacement a few feet away with 7-

inch casing in it and produce a much -- much more gas. He said that would optimize the production.

So, you know, we're looking at a situation here that's not described by the rules.

What I'm concerned of is if we say that this is a workover, when actually we're saying that deliverability slope does not describe this well, we're -- we're affecting other wells and other processes to assign an allowable rather than addressing the problem of this well.

MR. AUBREY: Would a change in the pool slope calculation now for this well enable the well to qualify for a retroactive allowable?

MR. CHAVEZ: I would recommend that, and this is off the top of my head right now, thinking out loud, right now my recommendation would be to -- that if the operator feels that they want a retroactive allowable assignment because of the deliverability, they could ask for that even back further than ninety days. There have been times when allowables even went back to the beginning of the proration period to account for it.

Now you can only go back so far, really, legitimately. You say, this is the way we describe this well.

So my question is yes, it could, if the operator requested it at a hearing.

MS. AUBREY: Mr. Chavez, will it present problems with the Aztec Division if the Aztec Division continues to use its definition of workover for it to come and appear at a hearing such as this so that the unusual case, or the exceptional well, or the unusual procedure, can be examined by the examiner and by the Division Director to determine on a case by case basis in the unusual case what qualifies this well?

MR. CHAVEZ: It would present problems. When there is a difference of opinion as to what a workover is, perhaps it would have been wise for the deliverability test committee to define workover when the rule was written but it just wasn't done, so we have to go by what the criteria was that we discussed , and what we're looking at under the gas rules that I referenced earlier, what is the productivite of a well and how do you change it?

You change it with Kh.

MS. AUBREY: Or with a compressor.

MR. CHAVEZ: If -- if the well had not had an opportunity to produce such that Q was representative, yes.

MS. AUBREY: That's all I have.

MR. STOGNER: Thank you, Ms. Aubrey.

Any other questions of Mr. Chavez?

I have no further questions of either witness.

Mr. Chavez may be dismissed.

Ms. Aubrey, would you like to make a closing statement at this time?

MS. AUBREY: Briefly, Mr. Stogner.

Tenneco's position is that in a situation where the Oil Conservation Division has an unwritten rule which says on the one hand that you must change the Kh in a well in order to have a workover, or on the other hand, put a compressor on the well which has no affect on the Kh, that it is arbitrary to decide that changing the downhole configuration of the well in order to increase the productivity of the well is not a workover.

If the Division wishes to decide only a changein Kh of the well qualifies as a workover and to write that rule down and to give the operators in the State of New Mexico notice of that rule, that's fine, but where the rule appears to be unevenly applied, where the rule appears to allow for the addition of a compressor not only when a well is completely incapable of production, but where a well, as Mr. Chavez admitted, is on line and is producing, it makes no sense to deny Tenneco a retroactive allowable when they spent money on the well, they changed the downhole configuration of the well, they have performed work on the well to qualify it as a workover under the industry definition of that rule and industry understanding of that rule.

We would ask that the examiner consider these matters on a case by case basis and look at them on a case by case basis, especially until, or unless there's some change in the rule or the rule is written down so that an operator has some way of knowing before he spends money whether or not he's going to qualify for a retroactive allowable.

MR. STOGNER: Thank you, Ms. Aubrey.

Is there anything further in Case Number 8944 at this time?

There being none, this 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 (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. 8944, heard by me on 23 July 1986.

Michael E. Stogner, Examiner
Oil Conservation Division