STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

ORIGINAL

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF C&D MANAGEMENT COMPANY TO REOPEN CASE NO. 14055, EDDY COUNTY, NEW MEXICO — Case No. 14055

MOTION OF TARGA MIDSTREAM SERVICES, LLC, TO REOPEN CASE TO OFFER PROOF OF COMPLETION AND RESULTS OF PRESSURE TESTING — Case No. 14575

OIL CONSERVATION DIVISION'S APPLICATION FOR REHEARING OF RULE AMENDMENT 19.15.14.8 — Case No. 14744

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSIONER HEARING

BEFORE: JAMI BAILEY, Chairman
ROBERT BALCH, Commissioner
SCOTT DAWSON, Commissioner

February 23, 2012
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission, JAMI BAILEY, Chairman, on Thursday, February 23, 2012, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

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ALSO PRESENT:

Florene Davidson

CHAIRMAN BAILEY: This is a meeting of the Oil Conservation Commission on Thursday, February 23rd, in Porter Hall in Santa Fe, New Mexico.

To my right is Commissioner Scott Dawson, designee of the Commissioner of Public Lands. To my left is Bob Balch, Dr. Robert Balch, designee of the Secretary of Energy, Minerals and Natural Resources. I am Jami Bailey, Director of the Oil Conservation Division.

We will be first hearing the minutes and then call the C&D case. We'll go into executive session and deliberate that case, come back out of executive session and announce our findings. And we ask for all attorneys to provide draft orders for Commission Counsel, who is Bill Brancard today.

Then we will hear the Targa case and go into executive session to deliberate that case, and then come back out and discuss the Oil Conservation Division's application for re-hearing of a rule amendment. So that's our agenda for today if you want to gauge your participation accordingly.

Have the Commissioners had a chance to read the minutes of the previous hearing?

COMMISSIONER DAWSON: I have.

COMMISSIONER BALCH: I have.

CHAIRMAN BAILEY: Do I hear a motion to

adopt the minutes of the hearing?
COMMISSIONER BALCH: I'll make a motion.
COMMISSIONER DAWSON: I'll second.
MR. BRANCARD: Madam Chair, if I may make a proposed change? On the first paragraph it reads, "The meeting was called to order of the minutes of the December 8th" -- that should be 2011, not 2012 meeting.
CHAIRMAN BAILEY: I'm glad you caught that. It seems like we're always very aware of it at the very beginning of the year. With that amendment, do we get adoption of the rest of the minutes?
COMMISSIONER DAWSON: I'll motion.
CHAIRMAN BAILEY: All those in favor?
I will sign on behalf of the Commission, with the change to be recorded by the Commission Counsel.
I would like to call Case Number 14055, Application of C&D Management Company to re-open Case Number 14055, in Eddy County, New Mexico.
I understand that the primary witness for C&D will be attending by telephone?
MR. BRUCE: That is correct.
CHAIRMAN BAILEY: And that opposing counsel has no objection?
MR. SWAZO: Correct.
CHAIRMAN BAILEY: If you'd like to be sure

is returned. As I said, the Division will hold off on plugging during that period of time.

MR. BRUCE: What time frame would you like proposed findings and conclusions?

CHAIRMAN BAILEY: Three weeks?

MR. BRANCARD: That would be fine.

CHAIRMAN BAILEY: Okay.

MR. BRANCARD: If you could, there was a little bit of some questions about which wells are in which status, if you could outline that in the facts and put in findings about which wells were plugged and the costs related to that so we have a dollar amount.

MR. BRUCE: Thank you, Commissioners.

CHAIRMAN BAILEY: Okay.

MR. SWAZO: Thank you.

CHAIRMAN BAILEY: Okay. Next we call Case Number 14575, which is the motion of Targa Midstream Services, LLC, to reopen case to offer proof of completion and results of pressure testing.

Call for appearances?

MR. SCOTT: Madam Chair, William Scott for Targa

MS. GERHOLT: Gabrielle Gerholt on behave of the Oil Conservation Division.

Madam Chair, may we have a few moments to adjust the table so that we have a clear view to the projector screen?

CHAIRMAN BAILEY: Yes. Shall we give you about 10 minutes?

MR. SCOTT: That would be good.

(A recess was taken.)

CHAIRMAN BAILEY: Let's just go back on the record. Okay. We've had appearances. How about opening statements?

MR. SCOTT: Thank you, Madam Chair. Very briefly.

Madam Chair, members of the Commission. My name is William Scott. I represent Targa Midstream Services, LLC. I have with me today two representatives from the company, Cal Wrangham and James Lingnau.

On December 20, 2010, this Commission entered Number Order R-12809-C, which authorized Targa to recomplete the Eunice Saltwater Disposal Well to permit injection of produced water, processing plant wastewater and acid gas into the San Andres formation at an open hole depth from 4,250 to 4,850 feet below the surface.

In that order, the Commission directed that Targa would have to file a motion to reopen this case within one year in order to come back before the Commission and present evidence that it has completed the well in accordance with the terms of the order, that it's operating the well in accordance with the terms of that order, and to present evidence of pressure testing to determine the extent of plume propagation and to set a time limit for injection into this well.

On October 27th of last year, Targa timely submitted its motion to reopen the case and to present evidence and this hearing was scheduled.

At today's hearing, Targa will demonstrate several points. First, Targa will show that it has completed the Eunice AGI well in accordance with the terms of order and is operating the well in accordance with all the dictates of Order R-12809-C.

Second, Targa will demonstrate that in accordance with the Commission order and under the direction of the Division's Hobbs District Office, Targa re-entered the Langlie Mattix Penrose Sand Unit Well Number 252, drilled out existing plugs to a depth of 4,073 feet and plugged back that well to 3,700 feet.

Third, Targa will present the results of a variety of tests conducted on the well, including pressure transient testing and will present calculations showing that the extent of plume propagation will not reach beyond a half mile in 30 years and that 30 years is an appropriate time limit for injection into this well.

Finally, Targa will demonstrate that it should be authorized to increase the operating pressure on the well from the current 1,300 psig to 1,600 psig, and Targa should be allowed to perforate the casing from 4,210 to 4,250 feet and to inject into that interval. That will provide an additional 40 feet of good injection reservoir and will still leave a 250-foot buffer between that and the bottom of the Grayburg formation.

We have as our first witness this morning Mr. Alberto Gutierrez.

CHAIRMAN BAILEY: Please stand and be sworn. I prefer to swear in witnesses one at a time.

(One witness sworn.)

ALBERTO GUTIERREZ

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. SCOTT:

Q. Could you state your full name please, sir?

A. Yes. My name is Alberto Gutierrez.

Q. Could you describe your educational background, please?

A. Yes. I have a bachelor's degree in geomorphology and a master's in geology from UNM in 1980.

Q. Okay. And could you describe your work background for us, please?

A. Yes. I'm a registered professional geologist, petroleum geologist and hydrogeologist. And I have worked since about 1975 on a variety of environmental and petroleum geology projects.

I am the president of Geolex, Incorporated, which is an environmental and geologic and engineering consulting firm. And I've been working on this Targa matter for several years.

Q. And have you testified as an expert witness before this Commission previously?

A. Yes.

Q. On what kinds of matters?

A. On acid gas injection permit applications, on various environmental matters related to oil and gas activities.

Q. Approximately how many acid gas injection well projects have you worked on altogether?

A. Probably on the order of about a dozen.

Q. Are all of those in New Mexico?

A. No.

Q. Where else have you worked on those projects?

A. I've worked on wells in Texas, in Michigan, and in Alberta.

MR. SCOTT: All right. Madam Chair, I would move the Commission accept Mr. Gutierrez as an expert geologist and hydrogeologist.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: He's so admitted.

Q. (By Mr. Scott) Mr. Gutierrez, could you take a look at that notebook that I put in front of you. It's labeled Targa Exhibit 1. Do you recognize that document?

A. Yes, sir.

Q. What is that?

A. This is the end-of-well report for the recompletion of the Targa Eunice SWD Number 1. This is a report which, really, the Commission doesn't -- or the Division doesn't require a specific report like this, but we make it a practice to put these reports together when we complete acid gas wells so that all of the information associated with that particular well through the date when it was completed is in one handy place for the Division and for our client.

Q. Could you just summarize quickly what is in that notebook?

A. Yes. Basically -- and this one is a little different in that it has an added section on reservoir characterization and modeling which was really responsive to the requirements of the Commission to do some additional testing and modeling of this particular well.

But basically, it has a description of the design of the well and what was done to originally permit the well and to design the well. It has a synopsis of the actual drilling and completion of the well.

In this case, it was a drill-out and recomplete project. It has some basic information on the local geology and hydrogeology. As I mentioned, this one in particular has all the reservoir characterization and modeling that was done for this well.

It also has all of the filings that have been done for the Division through the period of time when this report was put together and has copies of electronic copies of all of the logs associated with the well.

Q. Now, if you could look at Exhibit 2 that I put in front of you. Do you recognize that document?

A. Yes. This is the PowerPoint presentation which we will be seeing in today's hearing, less the fact that there have been a couple of either typographical corrections or corrections that resulted from the meeting that we had on Monday with OCD that I've incorporated into the presentation that you'll actually be seeing. I don't think it's reflected in this copy, but I have made available a revised version that will be consistent with what this is. But there's no substantive revisions.

Q. Does that PowerPoint presentation summarize the pertinent information from the notebook which is identified as Targa Exhibit 1?

A. Yes. And it has one additional slide that was added as a result of the meetings that we had with OCD and in reviewing the Division's prehearing statement.

Q. And then if you could look at what we've labeled as Exhibits 3A through 3D. Do you recognize those documents?

A. Yes.

Q. What are those documents?

A. These documents are essentially the history of injection pressure and annular pressure in the well, as well as a printout of all of the hourly data since the well initially began injection from early August or mid-August, I'm sorry, through about a week ago.

Q. And Exhibits 3A, 3B and 3C, those are charts that you prepared?

A. Yes, indeed. These are charts that are prepared based on the data that are included here.

Q. That's the data in 3D?

A. Yes.

Q. And Mr. Gutierrez, are you familiar with the Commission's Order R-12809-C?

A. Yes.

Q. Did you review that in connection with your work on this matter and in connection with preparation of today's hearing?

A. Yes, I did. That order is what laid out the requirements that the Commission expected of Targa as a result of recompleting this well. And I used that order basically as a checklist, to make sure that we got everything done that had to be done in order to put the well back into service.

Q. So if we could then turn to your PowerPoint presentation. If you could start taking us through that, please.

A. Sure. The goal of the presentation and the goal of the reopening of this hearing is to basically demonstrate to the Commission that Targa has complied with the requirements of the order in the recompletion of the Eunice Gas Plant SWD Number 1. Furthermore, that Targa has conducted the specific testing and analyses that were required by the Commission and that would support our three requests which we are making of the Commission to modify the order.

The first request, as Mr. Scott stated earlier, is to authorize the injection for a lifespan of at least 30 years for the Eunice Gas Plant SWD Number 1; second, to establish a new maximum allowable operating pressure for the anticipated mixture of TAG and water that would be 1,600 psig, and that is supported by the step-rate test that was witnessed by the Division and was performed on the well; and then to authorize perforation of an additional interval, about 40 feet of the upper portion of the well above the open hole, to provide some additional thickness of the reservoir and some additional porosity that could reduce the ultimate size of the plume after 30 years.

Now, currently, I don't think Targa has specific plans to perforate that zone. But what we are asking for is the ability to do that should it become necessary in the future.

Okay. So let's go through -- I've got a list of all of the items that were required by the order, and I want to go through and point out for the Commission where all of the information that documents that we have complied with those requirements.

The first is that the well was completed according to the specific design and specifications that were required by the order, and that is included in the various C-103s and C-105s that were submitted during the workover and completion of the well. Those are located in Appendix D in this end-of-well report.

Q. So we're clear, when you mention the end-of-well report, that what's been identified --

A. That's Exhibit 1.

Q. Thank you.

A. The second is that the Commission required that the Division approve the H2S contingency plan that was submitted by Targa prior to initiating the injection, and that has been done.

Furthermore, there were original C-115 filings that had been submitted prior to the initial hearing by Targa that needed some corrections based on the units that were included. And we have filed proof that those filings have been corrected, and those are also included in the end-of-well report, also, subsequent filings for the reinitiation of injection into the well.

I want to make a point that prior to our last hearing, we had already corrected those C-115 filings so that -- we're just having additional documentation here.

Secondly, the proof that the remedial work on the Langlie Mattix well, in other words, the taking out of the lead wool that was in the bottom of that well and the improper plugging of that well has been completed and that the well has been replugged to 3,700 feet and now has no longer a potential to be exposed to the top of the San Andres formation.

Secondly, the open hole logs which were done of this well and specifically the detailed microimager log that was done of the well as per the requirements of the order are also included in the end-of-well report.

Also, in Number 6, the reservoir tests which were required traced both a tracer and temperature injection survey and a pressure transient test as well as a step-rate test. The results of all those are discussed in Section 6 of Exhibit 1 and have further reports and details in the Appendix L.

In addition, there were two MITs completed in the well. The well had an MIT completed shortly after the recompletion in July. Then when the surface facilities were brought online and the well initially started injection in September or end of August, it was discovered that there was a packer seal leak in the well and that injection was ceased until that packer seal leak could be replaced or the packer seals were redressed and that could be fixed. And that was in September of 2011. September 21st, as a matter of fact, was the completion of that. And there was another MIT performed at that time before the well was brought back online.

We also have in Exhibit 3 the readings from the pressure gauges which are required for measuring the injection of acid gas and wastewater into the well, and we will discuss those in this presentation. Also, our calculation for the time it will take the acid gas plume to reach half a mile from the disposal well, that is included in Exhibit 1, Section 6.6. It's also going to be detailed in this presentation.

And then a request based on the step-rate test for the setting of an MAOP. The original order set a temporary MAOP of 1,300, and this is to set an MAOP based on the actual anticipated mixture of TAG and water that will be introduced into the well. And lastly, the request to perforate this additional 40 feet at the upper portion of the injection zone.

I'm going to go through each one of these. I'm going to try and do it without going into an unnecessary level of detail, but I want to make sure that we cover it in sufficient detail that the Commission is well aware of what was done to the well and how the order has been complied with.

So I'll just start going through them one by one. And please, Commissioners may feel free to interrupt me if there is anything that isn't clear or that you would like more information on.

The well was completed in May of 2011. These details were submitted in July. There was still some -- and the well was completed as per the requirements of the order. We put in an additional liner and then completed the well with a permitted injection interval of about 600 feet from 4,250 to 2,850 feet.

We replaced the tubing in the well with a coated tubing that prevents corrosion, given that we are injecting a combination of acid gas and wastewater into the well. We put a new subsurface safety valve, which is our standard design in these wells, to prevent any kind of backflow. There are meters and gauges to report injection pressure and volume. Those aren't really shown. This is just a wellbore diagram. And all those details are documented in the C-105 which was submitted in July.

At that time, injection had not been restarted because the surface completion facilities itself were still being worked on.

Q. Before you move off that slide, let me ask, Mr. Gutierrez, the tubing that you installed, that's equipped to keep the gas under pressure?

A. Yes. The tubing will allow for the injection of the gas under the MAOP.

Q. Okay. And Targa is maintaining within the tubing casing annulus corrosion-inhibiting fluid?

A. That's correct.

Q. And the packer was placed within 100 feet above the casing shoe and open hole interval?

A. Yes, sir, it was.

Q. Thank you.

A. The second requirement simply was that there would be an H2S contingency plan approved prior to injection of the well. This was approved in August of 2011, and there's a copy of the email that constituted that approval.

The third item is the C-115s. I already mentioned those C-115s have been filed on a timely basis. The old ones were corrected, and they were submitted back in December to the Division and they are accessible in the C-115 database.

The Langlie Mattix Penrose Sand Unit Number 252 was the well that was required to be plugged. It was a well that did not belong to Targa, but Targa obtained permission from the operator to do the remedial work. We entered the well. We drilled out the plugs, removed the old lead wool, which wasn't that difficult, fished it out.

And we drilled it out to 4,073 feet, which is roughly the top of the San Andres and the base of where that well was originally drilled to. And we plugged it back using a retainer and squeezed cement and then verified the plugs and we filed a C-103 with the Division in June, too, and that was approved back in June as the final documentation of the plugging of that well. So we're very comfortable that now that well, which was a potential conduit to the Grayburg, is now no longer one.

We then did a pretty extensive logging program, as we proposed and as required by the order, in order to support the analysis of the reservoir that we were required to do. We also took, by the way, sidewall cores on a number of the zones in the injection zone to the extent that we could, based on the fact that that was an old well and that when we re-entered it, in some cases, the recovery of some of those sidewall cores was not that great. But we were able to get sufficient cores to be able to help us in the characterization of the reservoir. And we have submitted the results and interpretations of those logs to the Division in the end-of-well report and to the Commission in Exhibit 1.

We also did a step-rate test back in July. We did -- as required, that test was witnessed by the Division. We did a pressure transient or fall-off test also in July, and we performed the tracer and the two temperature surveys. One was during the actual step-rate test and another one was following the tracer survey. So we did an overkill, I think, on the injection testing of the well, but it gave us some good information. And the results and those interpretations allowed us to do the reservoir analysis that is presented in Exhibit 1.

Q. A couple of questions there, Mr. Gutierrez. The step-rate test was performed after completion of the well but before injection of acid gas; correct?

A. Correct. And the step-rate test was performed using water.

Q. And the tracer and temperature surveys were also done after completion and while injecting water; correct?

A. That's correct.

Q. Okay.

A. Two MITs were done on the well, an original MIT back in June. And then after initiation of injection on August 26th, it was discovered that there was some communication with the annulus. Targa ceased injecting. They had the flexibility, fortunately, at the time, still had an SRU that was operable. So they ceased injecting acid gas when that was discovered, continued to inject water, however, until the well was repaired on September 21.

What we did find is that it did have a packer seal leak, and those packer seals were redressed and put back down. Then a second MIT that was successful was completed in September of 2011, prior to the restarting of the well. We'll see the effects of that actually on the pressure plots which we'll go through later.

Q. And a C-103 was prepared and submitted in connection with that second MIT?

A. Absolutely. And the C-103 was with a chart which was signed off by the OCD during the test, and was also submitted during that test and prior to the initiation of injection again.

The topside facilities -- just to go through a little bit of the timeline here, the topside facilities were completed and injection commenced on the 24th of August. Very quickly thereafter, as you'll see from the injection records that I will show shortly, it was noted that there was some communication between the tubing and the backside, and that was noted as a result of a pressure increase on the backside, and that caused us to stop injecting acid gas, re-run the gas through the SRU and then schedule a workover to try and determine whether we had a packer seal leak or a tubing leak.

Indeed, what we found was that there was a packer seal leak. Those packer seals were redressed, put back in, and then it was MIT tested again.

So again, this is a timeline just to document the things that we've gone through. We resumed the mixed TAG and wastewater injection on the 23rd of September, 2011. This start-up period has included a number of pressure control issues. It seems like with all of these wells, it takes some time primarily to get -- the wells behave generally pretty well. But the start-up oftentimes requires some significant modifications and fine tuning, if you will, of the compressor and the compressor controls, because these things are fairly sensitive and have to be adjusted. And that usually takes a period of several months while you're getting the well up and running.

The TAG has been routed to the SRU during shutdowns whenever the compressor would go down or when the initial seal leak was detected. The annular space pressure has been monitored and has been bled down pursuant to discussions between the Division office in Hobbs and Targa.

That pressure has been kept at near zero and has not had to be bled again since November, because the initial pressure effects had already stabilized.

We have proposed to the Division, and I think in the conversation that we had with E.L. and with Mr. Jones on Monday, we explained why we would like to keep about 250 pounds or so on the backside of that, that will aid us in identifying any potential tubing or packer seal leaks in the future. So I think we'll be looking to bring that back in line.

The data confirms that the leak was fully repaired, and we kept zero pressure on that backside since December, and the compressor controls with being fine tuned. And it is improving the reliability of the compressor.

Let's take a look at the injection records, if we can now.

Q. Mr. Gutierrez, this is essentially what's been identified as Exhibit 3A but just with a couple of explanatory notes added in?

A. That's correct. This is just a picture of the injection pressure and the backside or what I will call the annular pressure. You can see on the graph that first well that we initiated injection on August 24th. And very quickly you can see that we started seeing a rise on that backside pressure and a drop in the injection pressure. That was where we detected the packer seal leak.

And the reason why the pressure has continued to vary somewhat, at least in that initial two or three months, is because even while in the period between where I've labeled in that green bar, "No TAG injection," that was between when the leak was discovered an repaired. They still did continue to inject produced water into the well but no TAG.

And that leak was repaired right at the end of

September there, and the pressure on the backside was then bled off. This next graph shows a kind of a blow-up of that time frame. You can see that where I show that arrow in a couple of places where they bled the pressure off of the backside as it builds.

One of the things that I think is important to remember, because I think it's a key feature of the safety feature of these wells, is that backside is a sealed -- basically, a sealed unit which we use to help detect potential leaks.

What happens is you fill that up with inert fluid. In this case here, we've got a corrosion-inhibited brine on the backside. In a dry gas injection well, we use diesel because that way, if we have an escape of acid gas into the annular space, the diesel not only keeps the acid gas at the bottom, it creates a hydrophobic environment to prevent corrosion.

In these wells, where you're already putting in wet acid gas or acid gas mixed with wastewater, we use a corrosion-inhibited fluid but that is a noncompressible fluid on that backside to accomplish the same objective. The only problem is that when you put that in, typically, it's quite a bit colder than the formation around it.

And so you put that fluid into the backside, and then you seal up that backside, you fill it up to the top. Then as that fluid heats up, just when it's stabilizing with the temperature of the surrounding rock, you get an increase in the pressure on that backside because there's nowhere for that pressure to go when that fluid begins to heat up and expand.

So that process, once you have it established and you understand where -- that that temperature effect has equilibrated, then typically, what we suggest is that we bleed that pressure off to about 300 pounds, 250 pounds on the backside. So that once you're in an operating mode, you can -- you will always have some fluctuation of pressure on that backside, simply because your TAG temperature that's going down the tubing and the rate changes and that affects that temperature on the backside. Also, you can have a little bit of ballooning of the tubing, which also increases the pressure on the backside.

But once you've established a routine injection process, then the only real variation that you should see on that backside is due to those temperature effects and due to the normal atmospheric pressure variations.

And then if you go out of that range, either the pressure goes higher than that range, that indicates that you've got some communication with that annular space, i.e. a tubing or packer seal leak. If it goes lower than that range, then that would indicate you may have a casing leak and you may be losing some of that fluid on the outside. That is why we recommend maintaining about 200 pounds on that backside.

But as of right now, what has been maintained on this backside is zero pressure. And you can see this -- this is the injection since the last time that the pressure on the backside was bled. You can see the annular pressure just sits at the very bottom here at essentially zero. It's between zero and 20 pounds, and you just can't see the variation there. But the data are all in Exhibit 3, and you can see there's very little variation.

The reason why I have suggested that we raise this pressure on the backside to about 200 pounds is it's not very easy to see any variation that would go below zero, because your gauges are not going to measure a vacuum. They're rated from zero, essentially, to about 1,500 pounds. So I think it's more prudent to do that, and I think we've had sufficient discussion with the district and they agree.

One of the things I wanted to show here is that while we still have had a number of compersson shutdowns as a result of control issues, when you look at the kind of seven-day trailing average, we are getting a much better control of the injection pressure there. And you can see it's running between about 790 and 800 pounds at the current injection rates.

Okay. The next item, and this is what we're going to spend the bulk of our time discussing, is the results of the tests which we did on the reservoir in order to be able to characterize -- better characterize the reservoir and to be responsive to the Commission's request to do an analysis that would allow us to establish an appropriate length of time and conditions to operate the well. The results and the detailed discussion of these interpretations are included in Exhibit 1.

Just to go quickly over and refresh your memory, we are here south -- about five miles south of Eunice is where the well is located at Targa's South Eunice plant. The actual acid gas is generated at a plant here in middle Eunice and is shipped via pipeline along the county road, a buried pipeline that includes monitoring, and it is also carrying, in a separate line in the same trench, the wastewater or the produced water that is being injected down here at the site where the actual compression facilities exist.

This -- just to refresh everyone's memory about the stratigraphy, the San Andres formation is located here. It's essentially a massive limestone dolomite carbonate formation. The injection zone is in a portion -- a lower portion of that San Andres formation from about 4,250 feet to 4,850 feet partially -- well, entirely currently in the open hole.

The well that was plugged isn't shown on this cross-section. This is intended to show the nearer wells that penetrated the injection zone that were of concern to OCD. This Santa Rita Number 2 is about a half mile away from the current injection well, and Santa Rita Number 1 is close to one mile away.

Q. The Santa Rita Number 2 is cemented all the way through the San Andres; correct?

A. It is. Although there were some less-than-optimal cement zones within there, and that was what the Division had expressed some concern about.

Q. And the producing zone for that well is the once Abo?

A. That's correct. I think it's actually the Blinebry at the present time.

Just to give a summary of what we did, we did geophysical logs for the injection zone where we could have access to the formation, because, of course, the well was already in existence and cased above that.

We did porosity and resistivity logging there. We also did the FMRI, as we call it, or the extended range microimaging log, which is high-resolution resistivity log which allows for a better understanding of any fracturing or faulting that could be in the area or in the vicinity of the wellbore.

We then did 32 sidewall cores between 4195 and 4,826 of which we had recovery on. We actually attempted more than that, but those were the ones we actually had recovery.

We then did porosity and air permeability for those samples, and we also used those samples to calculate irreducible water and CO2 permeability.

We then did a step-rate test, which we performed at rates running from half a barrel a minute to five barrels a minute. The actual proposed maximum injection rate for this well runs at about three barrels a minute in terms of combined acid gas and wastewater. That was a total of 4,075 barrels a day, which is a combination of the acid gas and the produced water.

We also did transient pressure and fall-off tests which were performed at both one and a half and three barrels a minute, which is the kind of range of anticipated injection. We did the same thing for the tracer survey, and we also did a temperature survey during the SRT and following the tracer survey.

In a way, these tracer and temperature surveys were overkill, but it allowed us to compare the results of both and we found that they are pretty consistent.

There is a more detailed picture of this log. This is in the microimaging log. It's a detailed-oriented resistivity log. What it basically shows is that we show some very high porosities, and this is what we also saw in the sidewall cores above 4,500 feet. We get into much lower porosities below 4,500 feet. And then also we did not see any faults or microfaults identified in the section.

But we do have a fair amount of vuggy porosity in the especially upper portion of that San Andres formation. And one of the things we've seen is that these porosity zones are very difficult to correlate over any distance when we compare it with other logs in the San Andres.

So while we may have some zones in the immediate vicinity of the well that take more injection fluid than other zones, and we'll go through that in a few minutes, once you get further away from the well, it's not clear that those zones are going to continue to just take water in a very restricted range, because you've got a lot of variations, both as a result of diagenetic fluids that have moved through the San Andres and maybe some original depositional control on that porosity.

We took sidewall cores. They're all labeled where we took them, you can see, all through the injection zone. And we had those analyzed. What we saw is that the porosities range from about 2 to 38 percent. The air permeabiltiy, very wide range, basically four orders of magnitude, from three-thousandths to about nine millidarcies, we had irreducible water from about .32 to about .6 in the lower portions of the reservoir. So we do have quite a bit of variation in that. And the lower portion is just basically a much tighter zone.

The step-rate test, we started with a background reservoir pressure, initial bottomhole pressure about 1,980 psi. We developed maximum pressure of about 3,450 psi at five barrels a minute. The detailed description of the step-rate test is included in Exhibit 1.

But what you can see is that we had a notable increase in injectivity at about the two and a half barrel a minute rate. And then what we also saw, and we'll get into it in the -- when we look at the temperature survey and the warm-back -- that at about the two and a half to three barrel a minute range, you've got a lot greater portion of the injection zone actually being invaded. At the very low rates, as you might expect, we were getting the bulk of the fluid going into these very poor zones. But once you raise the injection rate, we got much more of the well involved in taking fluid.

Of course, the step-rate test is done using water. Now, because of the fact that you use water, but in reality we're going to set an MAOP based on a mixture of water and TAG, you have to correct for the reduction in the specific gravity of the fluid that you're injecting when you analyze these in order to come up with an MAOP.

We initially -- and what is initially included in this Exhibit 2 that was submitted to the Commission, we have modified -- after our meeting with the Division on Monday, we had originally requested a mixture-dependent MAOP that would be -- essentially reflect an injection of water only at one end and TAG only at the other end, and then an average mixture which is the mixture we intend to inject on a routine basis in the middle.

The reason for that is because when you're injecting all water, the MAOP would be about -- that the step-rate test would allow would be roughly around 1,400 psi. When you're injecting all TAG, because of the difference in density, that same MAOP at the surface would be about 1,700 psi.

So typically, using the formula that OCD requires for calculating what would be an appropriate maximum injection pressure, you take into account that specific gravity of the fluid.

So what we've done, because we felt it would be very difficult to really regulate or monitor exactly what mixture was going in all of the time, what we've requested is an MAOP that is less than what the step-rate test would show for the proposed mixture. The step rate justified an MAOP of about 1,640 pounds for the proposed mixture. We're requesting 1,600 pounds for that proposed mixture and just have a single MAOP at that target mixture.

This graph shows you what I was just describing. If you correct the surface pressure for the different densities, you basically get these three parallel lines. The lowest one is for pure water injection, the highest one for pure TAG injection. You can see the break point is essentially at the same rate here, and that is at about 1,700 psi for TAG only, 1,640 for our mixture and about 1,420 for water only.

Just to refresh peoples' memory, the current

MAOP is 1,300 psi, and that would be for the proposed mixture.

So basically as -- because of the mixture changes, the specific gravity of the fluid is reduced as you add TAG. But for the kind of 60/40 TAG mixture that we are proposing, we're requesting an MAOP of 1,600 psi.

The transient pressure and fall-off tests are shown here. We measured the pressure fall-off and then modeled it. What we found based on that is that we've got an effective permeability just at about three-quarters of a millidarcy on the overall injection zone.

The tracer survey here indicated that we have greater injectivity 4,500 feet and that the zone of injection extends to a greater depth once you reach your target injection rate of three barrels a minute. You can see here -- you can't really read it too well on this screen. I think you will be able to on your diagram, and also this figure is included in Exhibit 1.

It shows that there are some variations clearly in the zones that take fluid. With this zone certainly taking more fluid and basically you see the majority of the fluid is being taken by this upper portion of the injection zone and much lower in the lower portion of the injection zone. This was based on all the data that we had from the sidewall cores and logs.

We broke up the reservoir into about seven or eight different zones, which are those zones that are shown on the earlier diagram. You can see the top and bottom zone, the thickness of the zone, the porosity, the cross-plot porosity, the water that we see in the -- in terms of irreducible water, and then the net porosity in terms of number of feet of that zone.

So you can see that, really in the main zone we're talking about, somewhere in the neighborhood of about 17 and a half feet of net porosity that we're injecting into.

This is the temperature surveys.

MR. SCOTT: If I can stop you there for one second? As a housekeeping matter, he reordered one or two of his slides. The one he is on now is page 29.

A. I'm sorry. I did move it up two slides because I thought it made more sense.

Now, the temperature survey data again shows basically the same thing we saw earlier, that when you raise the rate, you increase the injection front to take up more and more of the well. So by the time you get to the three barrel a minute rate, you've got the bulk of the zone between the top of the well, 4,250 and 4,750 involved in taking the fluid.

This is a slide that was added to my presentation. It is a slide that is modified from a slide that was provided by the Division as part of their prehearing statement. This was a slide that was shown also at the initial hearing that is essentially a representation of what would be the distance that we would expect to see radial flow or a plume away from the injection well over time at the maximum rate.

You can see that what has been included here is a maximum rate of 4,075 barrels a day, which is both TAG and wastewater. It has an effective porosity calculated at about 8 percent, taking into account residual water, which is generally consistent with what we're seeing. It's a little on the low end of what we see in the well.

But I don't have a lot of concern with the Division's representation. However, what I do have concern about is that these upper three curves, the one for injection thicknesses of 50, 100 and 150 feet, I think significantly underestimate the actual injection thickness that the well is taking.

I think what -- we don't know exactly, but the best that we can predict from the tests that we've done is that the actual curve should run somewhere in this yellow and red zone.

We've got a zone that's accepting fluid that's about 300 feet thick and a net porosity of about 18 feet in that zone, which would end up resulting in the calculations that we came up with of after 30 years, we've got roughly about a .35 mile radius of invasion of the San Andres, and at the half-mile range, it would take approximately 75 years to get out to half a mile.

Again, we all know that radial flow is an approximation, but it is really the best one that we have for being able to characterize the flow in this unit.

Okay. So to summarize what our findings were, the reservoir conditions are relatively cool. I did not anticipate, frankly, a pressure -- I mean a temperature as low as what we saw out there. I expected it to be probably about eight to ten degrees warmer based on other San Andres wells that we looked at, but that was kind of an interesting result.

That's another issue that really helps us in a way, though, because that reservoir pressure -- I mean the reservoir temperature being 83 degrees, means that the TAG that we inject is going to have a higher specific gravity than under a warmer reservoir, and so it is going to actually occupy less pore space than it would be if it was warmer. So that actually helps us.

The initial bottomhole pressure was roughly

1,978 or 1,980 pounds. And we didn't see much change in that after, and it went back to that very quickly after the step-rate and injection fall-off tests.

Roughly about 50 percent of the section accepted fluid during injection, and that increased with the rate, as we've discussed earlier. There's no evidence of faulting or any kind of lateral continuous features that would have the zones that are taking a lot of fluid near the wellbore carrying out any significant distance without being integrated into the overall reservoir.

So how do we then calculate what is going to happen in terms of injection over time? This is the well as currently completed. This shows our calculations. It's the volume. Basically, we look at the available volume in that half-mile radius which is roughly about half a billion cubic feet of pore space. We then look at the volume injected and what is that volume when, under the actual reservoir pressure and temperature conditions, and it winds up being about a little over 7.3 million cubic feet a year, which means it would take about 62 or 63 years to fill up that half-mile radius, and that in 30 years, we'd be looking at somewhere in the neighborhood of about a .35 mile radius.

This is a diagrammatic representation of the same, with the key wells that were of concern shown out here, the Santa Rita 12 and the Santa Rita 2, which we showed in the cross-section. The Santa Rita 2 being the closest well, that is that Blinebry well that is located just under half a mile away.

This represents our best projection of the radial flow after 30 years, the green line.

Q. The inner of the two circles on that diagram?

A. That's correct. The outer was just showing the half-mile circle.

I would like to now discuss what our justification is for our maximum operating pressure. As I mentioned, the current MAOP is 1,300 psi. Using the SRT result at our proposed mixture of 60 percent TAG and 40 percent wastewater or produced water, that would yield a 1,640 psi MAOP using the formula that OCD uses for calculating MAOP.

Clearly, as the mixture changes, so will the specific gravity of the injection fluid, and that does affect the pressure. So while there's going to be some variation in that based on summer and winter flows, we believe that it is going to be possible to maintain essentially a target mixture rate of about 60/40 TAG to wastewater and consequently, we're asking for an MAOP of 1,600 psi for the well.

Now, we don't know how it will develop over time but, frankly, we believe that we're never going to get anywhere close to that MAOP. When you look at the injection history of the well now, since the compressor has been more consistently running, we're running about 750 to 800 pounds. So I don't think we're going to get anywhere near that MAOP but, nonetheless, it's what the step-rate test would justify. And I would like to have the opportunity, if we should run into injectivity issues down the road, to be able to get up to that MAOP.

As I mentioned, this was the same graph you saw earlier that shows how we calculate the MAOP and how it fits into determining the specific gravity. As you can see, the specific gravity of the injected fluid at a mixture of 60/40 is about .89. Pure TAG would be .83 and pure brine water is about 1.01.

We also are requesting the ability, if we should need to in the future -- and this would be also to reduce the need to have to operate at anything close to the MAOP. There is about 50 or 60 feet above the open hole in the liner that we put in that is opposite a very good injection zone in the San Andres.

Now, the Commission requested that we limit our injection to below 4,250 feet. And the main reason for that was to protect the upper portion of the formation and the potential impact on the overlying Grayburg production. We feel, however, that it would be prudent to be able to perforate about 40 feet, which has got some very good porosity in it in the very bottom of that liner below the packer to allow for basically spreading out that injection even further, should we need that in the future.

It is not something that Targa is proposing to do now. However, I will show you that if we did that, it could reduce our overall radius over 30 years, not by a lot, but by at least a measureable amount.

What that means would be how that would look in the well. Right now, we've got our packer right in here. We've got the liner that we put in below it. Right now that liner is just not perforated. It's cemented in using that acid-resistant Corrosacem cement. We would be perforating 40 feet from roughly 4,210 to 4,250, which is essentially near the bottom of the casing. The bottom of the casing where we start the open hole is about 4,258 right now.

This is the same slide that you saw earlier. If we include that additional injection interval, you can see that we increase by about 10 percent the available volume in that half mile and consequently increase the time that it would take to fill up that half mile by about 10 years, a little over 10 percent. We also would decrease the radius from about .35 miles to about .32 miles. So it not a huge increase.

One of the things that's important to remember is that radially, as you get farther and farther away from the well, it takes a lot more volume to go from let's say .3 to .35 five miles than it does to go from .1 to .6 miles -- I mean say from .1 to .15 miles, because obviously, the circle is getting bigger and it's taking more and more area to expand that radius. So that's why the difference isn't huge, but it is still significant.

Here you can see the two pictures together. The green line being if we don't open up that upper interval, the blue line being if we do open up that upper interval. It just reduces the footprint over 30 years. You can still see that we are well away from these two wells in that area of concern at approximately the half-mile radius.

One of the -- so basically, this is my last slide to summarize what we are asking for. One, is we would ask that the Commission authorize us to inject into the well for 30 years. We would request that MAOP be raised to 1,600 psi, as justified by the OCD-witnessed step-rate test. And we would request that we be authorized to perforate that upper interval if it would be desirable at some point in the future. Of course, prior to doing that, we would have to file the appropriate C-103 and workover requests with the Division that would specify exactly how we would do that. Those represent what Targa is asking for in this hearing.

Q. Thank you, Mr. Gutierrez. In your opinion, would the Commission's approval of the 30-year term for injection, the increased operating pressure and the authorization to inject into that upper 40 feet, be protective of public health?

A. Yes.

Q. Would those approvals also protect fresh water and the environment?

A. Yes.

Q. And would those approvals protect producing zones and prevent waste?

A. It would.

Q. Have you had a chance to review the Oil Conservation Division's prehearing statement?

A. I have.

Q. In there, they provide three suggestions for the Commission to consider, one of which is that Targa should conduct appropriate testing on the reservoir. Have you formed a view as to the appropriateness and timing of such additional testing?

A. We discussed this with Mr. Jones and Ms. Gerholt on Monday. The issue is that the injection testing and fall-off testing was done prior to the injection of TAG into the well, and that after some period of injecting TAG into the well, that those conditions and the zones that may be taking fluid would probably be expected to increase, so that the results of the current tests would actually be very conservative in terms of what portions the vertical thickness of the well would be taking flow.

So there was some question as to whether it might be useful or provide additional information on that to do a similar temperature kind of survey down the road, some amount of time down the road, to compare with this initial survey that was done now.

I don't think that's necessary, but it might yield some very interesting information. If that were to be the case, I would prefer that that kind of test be after a significant period of injection, maybe 10 years, where we've had enough effect on that area in the immediate vicinity of the borehole to see some real change. If we were going to do something like that, I would suggest it might be in that kind of a window.

Q. So it would be your recommendation to have a 30-year injection term, but have this test performed after 10 years to check on progress of the plume?

A. Yes.

Q. The Division also recommended that the Commission order that a mechanical integrity test be conducted once a year, as opposed to five years. Do you have a perspective on that?

A. Yeah. I've discussed this at length with E.L. down in Hobbs in the context of a number of other wells that we're working on. And I don't think that's an unreasonable request.

I believe that if we raise the pressure on that backside a little and monitor it closely, that that serves -- its intent is to serve as an ongoing MIT test all the time.

But an MIT test, frankly, in these kinds of wells, you don't have to shut down the well to perform the test. You can pressure up the backside to 500 pounds and chart it with the well still operating, and then reduce -- bleed off some of that pressure to bring it back down to the 250 rate.

I don't think it's an unreasonable request. I think it is doable. I don't think it's necessary because we have the ongoing MIT test, if you will, of monitoring the backside pressure, but I would not think that that is an unreasonable request.

Q. The ongoing test you refer to is the pressure monitoring data which is reflected in Exhibit 3D from Targa?

A. Yes. And that pressure monitoring data is fed back to the PLC at the plant so that they would be immediately aware of any significant rise or loss of pressure on that back side.

MS. GERHOLT: Excuse the interruption. 3D, I don't have. Was that what was emailed to the Division last week?

MR. SCOTT: It's the raw data that supports --

MS. GERHOLT: We did receive that. We just don't have that in our exhibit as 3D. Thank you.

MR. SCOTT: Sure.

Q. (By Mr. Scott) Finally, the Division made some recommendations concerning the H2S contingency plan Targa submitted, specifically that there be a provision included to address what happens if the well itself ceases to be operable.

Have you seen that type of condition imposed in any other H2S contingency plan that you've been involved with?

A. No. The H2S contingency plans are typically -- not typically. I mean by Rule 11, they're required to provide information on how a company would deal with an accidental release or leak of H_2S, either from a plant or from a well or anything else. So it's really geared towards how you protect public safety as a result of a potential leak.

I think what we were discussing or what the Division was, and we'll wait to see their testimony, but based on what we discussed, it was my understanding that what the Division is seeking would be some kind of forethought and perhaps documentation of what would be the approach that would be taken to appropriately deal with a failure of some sort of the well.

Because clearly, once the SRU is shut down at this facility, and, in fact, the end purpose of these acid gas injection wells is to be able to shut down units that cause additional air quality impacts, if the well had to be shut down, you're basically shutting down the plant and shutting down the producers that supply gas to that plant.

So what I think the Division is talking about there is coming up with some kind of contingency for how you would manage the operation of the well in a potentially compromised situation until you could deal with that through a workover process.

We, in effect, are dealing with that on

another well, and we're working very closely with the Division and monitoring it on a very close basis between the time when we detected that there was a potential leak in that well and when we're going to be able to work that well over.

So I think the Division is thinking, and I think it is prudent to think about, to develop some way of dealing with those things down the road. But it's not really part of an H2S contingency plan.

MR. SCOTT: At this time, Madam Chair, I would move the admission of Targa's Exhibits 1 and 3A through 3D.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No.

CHAIRMAN BAILEY: They are so admitted.

(Targa Exhibits 1 and 3A through 3D are admitted.)

MR. SCOTT: I would also move admission of Targa's Exhibit 2, which Mr. Gutierrez modified slightly this morning and I have on a thumb drive that I can provide to the court reporter, so it would be an exact copy of what was presented during his testimony.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: I don't have any objection because the modifications were minor, and one of the modifications was based on an OCD exhibit that is available currently to the Division.

CHAIRMAN BAILEY: So admitted.

If you'd give that thumb drive to the court reporter.

(Targa Exhibit 2 is admitted.)

MR. SCOTT: No further questions for this witness.

CHAIRMAN BAILEY: Any cross-examination?

MS. GERHOLT: Yes.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Good morning, Mr. Gutierrez. You've been talking about the step-rate test. And through the documentation that Targa provided the Division, I note Targa notified the Division that a step-rate test was going to be conducted. However, I cannot locate the name of the individual within the OCD district office who witnessed the step-rate test. Do you know who that was?

A. Unfortunately, I don't. But I can find out hopefully during a break. I could call the staff member who was there from our company, Jim Hunter, that was there, and maybe he recalls who it was that witnessed the test. He's in Artesia cranking up another AGI right now.

Q. If you could. Because I've contacted our district office, and we don't have that information available. So if you contact your employee, I'd appreciate it.

A. Sure.

Q. Thank you. Targa is requesting an injection interval from 4,210 to 4,850; is that correct?

A. That would be if we were allowed to perforate this additional 40 feet.

Q. So it would be perforated injection interval of approximately 640 feet thickness or a nonperforated -- so the perforated interval would be 600 feet; is that correct?

A. No. We would have essentially between 4,250 now and 4,850, which is 600 feet. That's open hole. So what we would be doing would be just perforating 40 feet of casing that exists immediately above the open hole below the packer. So it would be a total of 640 feet of formation that would be open to injection if that perforation took place.

Q. If I could please draw your attention to what is the Commission's Slide 30, and I believe it's Slide 31 on your slide that is being projected.

A. Let me pull that back up, if I can. Is this it?

Q. Yes, sir. According to this slide, Targa asserts that the zone that would accept the fluid is approximately 302 feet thick?

A. Yes.

Q. If I could have you turn to what is Targa Slide 22.

A. Which slide?

Q. I have it marked 22. It's entitled, "Sidewall Cores."

A. Sure.

Q. Thank you. Mr. Gutierrez, would it be possible to identify for the Commission on this slide which 302 feet that Targa believes will accept the injected material?

A. It would be easier on -- in fact, we've really shown that specifically on the slide that is called, "tracer survey," because that's where we got that distance from, so I could show you that. And it's from here through essentially approximately here.

Q. So from the top of the distribution of injection line to a third of the way down is 11.9 percent injection interval; is that correct?

A. That's right. I think it's described here, which is about 51 percent of the total injection zone. There's high injectivity between 4,355 or basically 40 -- it starts -- there's very high injectivity between those zones. There is some injectivity between 4,250 and

4,280. Then we get into some pretty high injectivity. Then we have no injection in these intervals. So when you TAG all that out, it comes out to about 302 feet.

Q. This is based on the logs and testing that has occurred pre-injection of acid gas? This is injection of water; is that correct?

A. That's correct.

Q. This 302 feet that Targa believes will accept the injection material, that's not an absolute that all 302 feet will take it equally; is that correct?

A. Oh, yes, that's correct. It will not take it equally, I mean at least in the immediate vicinity of the wellbore. Once we get farther away from the wellbore, our experience with the San Andres has been that the formation has sufficient variability that tends to spread out over -- it tends to equalize as that front moves away. But yes, it does not take it equally. In fact, that's what this shows, is that there are zones that take more flow than others.

Q. I believe you testified on direct examination that it would be reasonable to include in a permit that at a later date, Targa be required to run, whether it's a tracer survey or some other test of Targa's choosing, to actually see where the plume is moving out into the formation; is that a correct summary?

A. No. I think what it was was to do some kind of a test that would see how the injectivity over the zone that's being injected into might have changed over time. But I don't think we talked about the actual trying to measure the expansion of the plume.

Q. And how do you think Targa could test for that?

A. Well, the way that you would do it would be to run another temperature survey or injection survey with a temperature warm-back so that you could then compare the results of this one to the previous one and then make some conclusions about what thickness of the reservoir is taking the injection.

Q. And I believe you also testified on direct examination that it was not unreasonable for the Division's request to have MIT once a year?

A. I don't think it's unreasonable. Although I do think that the continual monitoring of that annular pressure and the injection pressure and temperature serve as an ongoing MIT.

Q. Correct. And at this meeting we had Monday with everyone, the OCD did discuss their data collection system, RBDMS; is that correct?

A. Yes.

Q. And that OCD, unfortunately at this time, cannot accept those pressure data in a usable format; isn't that correct?

A. Yes, it is.

MS. GERHOLT: If I may have one moment, please?

I will wait for Mr. Jones to testify about the Division's suggestion on a contingency plan. But I have no further questions of this witness.

CHAIRMAN BAILEY: Commissioner Dawson?

COMMISSIONER DAWSON: Just a few questions.

EXAMINATION

BY COMMISSIONER DAWSON:

Q. The request of injecting from 4,210 to 4,250, that zone -- the porosity in that zone, would you think that would be pretty similar to Segment 2 which is roughly 19 and a half percent on the crossplot?

A. Yes, at least that.

Q. It's a very porous zone compared to that Segment 2, probably, which is taking most of the fluid?

A. It's about the same as that, yes, sir.

Q. On the contingency plan that has been discussed with OCD, it's not really set in concrete yet that is, the contingency plan? I heard you talking about the contingency plan more or less regarding the wellbore.

Did you guys talk anything about the pipelines that it's delivering to the plant, the contingency plan concerning that? Have you talked about that before?

A. The pipeline that takes the low pressure acid gas from the middle Eunice plant to the south Eunice plant is monitored and is double lined. And it is included in the existing H2S contingency plan if there should be some leak or failure of that line. But other than that, no, we haven't discussed it any further.

Q. On the Santa Rita Number 2 well, you said it's producing from the Blinebry Formation?

A. Yes.

Q. Do you know what the upper perforation depth is on that well in relation to the lowest injection interval on your AGI well?

A. I don't have an exact number on that. I would say on the order of several hundred feet. It was part of the original -- that's something that was presented in the original hearing and the C-108 application that was submitted originally. But off the top of my head, I can't recall.

We do have a little bit of additional natural protection, unfortunately, in some ways because the basal part of that San Andres is pretty tight. So it's not taking a lot of fluid in the bottom say hundred feet.

Q. It looks like the porosity is only about four and a half percent down there.

A. Yes, sir.

Q. When you re-route your TAG to the SRU, what kind of monitoring do you have on that. Is that monitored pretty well?

A. The SRU is subject to pretty extensive air monitoring associated with that unit, and it is incorporated into the H2S contingency plan for the plant. I don't think there's any physical movement of anything that is required to re-route that. It's just a manifolding valve.

However, you should be aware of the fact it is not Targa's intent to continue to operate that SRU. Ultimately, they will shut that down. That's part of the reason for this well.

MR. SCOTT: Madam Chair, if I might? Pursuant to a settlement agreement with the NMED, that SRU is now shut down. It had a six-month overlap period while the well was started up. And at the end of that six months, the SRU was to be shut down, and we're right at the end of that six-month period right now.

COMMISSIONER DAWSON: That's all. Thank you.

CHAIRMAN BAILEY: Commissioner Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. So you're asking for -- Targa is asking for three separate MAOPs depending upon the mix of injecting. And you're predicting that it's primarily going to be 60/40 as an average. What's the ultimate source of the gas and the ultimate source of the wastewater?

A. First of all, originally, we were asking for essentially this mixture-dependent MAOP. But after discussion with the agency and with Targa about how difficult it would be to monitor exactly what that is, what we settled on was just asking for a single MAOP based on the anticipated mixture.

Q. That's 1,630?

A. That's a 1,600, yes. Now, to answer your question about the source of the water, the bulk of the water that is being injected is cooling tower blow-down water from the plant, the middle Eunice plant. They originally did also inject in this well for many years injected wastewater from a Texaco remedial groundwater remediation effort that was being conducted at the south Eunice plant.

That water is no longer being taken by this well, so it is strictly wastewater from the plant, primarily comprised of cooling tower blow-down, and that's the source of the wastewater. The source of the TAG is the natural gas processing that takes place at the middle Eunice plant, the aiming tower there.

Q. You actually brought up another question that I had there. The temperature of the reservoir, 83 degrees, pretty low, likely the result of the previous injection of wastewater. How long did that wastewater get injected? Do you have any idea of how far that may have spread from the wellbore?

A. I don't. That injection had taken place over quite a number of years at varying rates, and we've not attempted to evaluate how far that water would have traveled. And it might have something to do with that temperature that we observed there, although it was a pretty significant buffering capacity of that formation.

And that's something that I also failed to mention that you brought up that I think merits some consideration. And that is that the San Andres has a huge buffering capacity, because it's essentially a massive limestone and dolomite. And I'm not sure that after some period of time and some distance away from the well that the character of that formation water would be substantively different due to the TAG injection because of the buffering capacity.

But in answer to your question, we have not calculated the distance or the effect of the previous injection.

Q. And another research that I'm familiar with, I believe that area of the San Andres is subject to flushing of meteoric groundwater from the west and may also attribute to the lower temperature?

A. It could, although that would be from some significant distance away from here. But yes, it could.

Q. The rate of three barrels a minute, is that going to be fairly sustainable so you can meet that 51 percent injection?

A. Yes. I think that's roughly the rate they're going to be -- that would be the rate they are injecting at currently and what they would be seeking to maintain.

Q. And your wastewater rate is going to be consistent because it's all coming from the plant's cooling process?

A. It is. Except it does change seasonally. So in the summer, they might have greater flows because they blow down those towers a little more frequently.

Q. So in the summer your water ratio may go up and in the winter it may go down?

A. Yes, sir.

Q. If you're going from 60/40 as an average, what would be the variation, summer to winter?

A. I think it would be maybe 65/35 to maybe 50 or 52/48, somewhere in that range.

Q. Not terribly significant?

A. No, sir.

Q. There was some discussion by both sides about the MIT test, annual MIT testing. Is there a way to take your ongoing monitoring and turn it into a pseudo-MIT test and report it once a year?

A. Sure. I mean we certainly could report a pressure graph that would show the pressure, just like what you saw displayed here, that would show both injection pressure. I would suggest not only the pressure but the injection temperature, injection temperature and then the annular pressure. And that could be graphed and made available.

I mean as it is, Targa and other operators of AGIs are required to keep those records and have them available for OCD inspection. But we have not been required in the past to turn them in. But certainly -- I mean that's data that's collected. It could be done.

Q. Could it be formatted in such a way that it would be acceptable to the RDBS system?

A. I don't know about that. That's an IT issue. I don't think their system is set up to be able to take those. Because the C-115, basically you report an average pressure, injection pressure for the month and total volume for the month and so it doesn't really have any kind of way of accepting annular pressure, for example. And I think the MIT is just kind of a -- they have a snapshot every -- originally, every five years, that's what they required, and now more recently, it's been every two years that you would basically get a snapshot of the integrity of the well.

Q. All right. In your core plugs, I do notice there's considerable variation in porosity, and then also the ability to take the water as you go down the injection interval. The permeability that was measured from those core plugs also had a lot of permeability?

A. Yes, sir.

Q. Do the high permeability and high porosity tend to correlate, or is it more variable than that?

A. I would say the answer is a guarded yes. They do tend to correlate. However, what we noticed is that, you know, in some cases, it was almost impossible to measure the permeability because the sample was so vuggy that when we get the sidewall core, it basically falls apart. But that implies that you're going to have pretty significant both porosity and permeability in that sample.

COMMISSIONER BALCH: Those are my

questions.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. I'm looking for lessons learned from the packer leaks and other issues that have developed for Targa and other AGI wells in the southeast.

What measures have you considered for ensuring that we don't continue to see packer leaks in the future or casing leaks? What suggestions and what policies?

A. Well, that's a question that we're considering very seriously now for quite a number of our clients. I think that it is -- you know, you try to be as prudent and careful as you can with those seals when you're inplacing the tubing to begin with. But you rely on the fact that typically -- first of all, we've never had a casing leak. The only leaks that we've seen are either tubing or packer seal leaks.

But taking one at a time, the tubing we now -- one of the lessons learned is that all of the tubing that we now put together as we install the well, one, it has all FX ultra threads which, basically, are much closer threads and much finer threads than eight-round thread, which is the normal tubing thread. So it provides a better metal-to-metal seal on the tubing.

However, the flipside of that is that you've got to be a little more careful when you put those together, and you have to have a torque wrench. You don't just throw the chain on them and slap them together. You put them together with a -- typically, we use a subcontractor that has a specific torque wrench, and we torque every one of those connections to exactly what the manufacturer specification is. That's one issue to prevent tubing leaks.

The other issue on the packers, we are working with Halliburton and other suppliers of those seals to try and understand why they fail when we pull them out of a well and try to determine if they've been damaged while stabbing into the actual packer.

Because the way these seals work, they're like piston rings on a piston, and there's six of them. And as they stab through the packer, they actually seal between the tubing and the packer. But they're actually on the tubing. They're not in the packer. So that allows you to be able to replace them.

So one of the things we're also looking at is having a section of tubing that has the profile nipples and all of the packer seals that would be available as a spare on the site that would allow for replacement of that. But still, I mean you still have to be able to shut the well down and get a rig out there, pull all the tubing and do that.

But we are working with Halliburton and Schlumberger that are manufacturers of those to either improve the actual quality of those seals -- those seals are specifically designed to be resistant to acid gas, so we haven't really seen corrosion. What we've seen is more physical damage that has occurred when they're actually stabbing into the packer. And I think that's what occurred in this case, because the seal leak happened almost immediately.

So all I can say is it's a work in progress. We're trying to improve that, but we're also looking at increasing the number of seals that we have. Right now, there's six seals in that string. We may end up having Halliburton construct some with more seals so that if you have one fail, you still have others that will help.

But it's clearly -- this is an issue that isn't just an issue for us. It's an issue that a lot of material scientists are working on to try and improve the technology.

CHAIRMAN BAILEY: We'll look forward to that.

Those are all the questions I have. Do you have any rebuttal?

MR. SCOTT: Just a couple of quick

questions just to clarify.

REDIRECT EXAMINATION

BY MR. SCOTT:

Q. Mr. Gutierrez, you were asked some questions about prior water disposal into this well. Targa actually applied to deepen this well from 4,550 down to the depth it's currently completed at; correct?

A. Correct.

Q. So the water disposal that occurred previously was from 4,550 and above?

A. That's right. So it would have been more into the upper portion of that zone.

Q. The H2S contingency plan, just so we're clear, that plan covers a leak that would occur at the Eunice plant along the Eunice pipeline or at the acid gas injection well itself; correct?

A. Or the surface compression facilities at the gas injection well itself.

Q. So the entire system is covered by the plan to protect public safety in that document?

A. Absolutely.

Q. Looking at paragraph C of Order 12809-C, under the section on mechanical integrity test, can you read that section?

A. Yes. This is on page 11 out of 14 of the order under the bullet titled, "Mechanical integrity test." It reads, "After installing injection tubing but prior to commencing injection operations and at least once every five years thereafter, the operator shall pressure test the casing from surface to the packer setting depth to assure casing integrity. Mechanical integrity test is also required whenever the packer is reset."

MR. SCOTT: Thank you. No further questions.

CHAIRMAN BAILEY: All right. This witness may be excused.

CHAIRMAN BAILEY: It's time for lunch. Let's take a break and come back at 1:00.

(A lunch recess was taken.)

CHAIRMAN BAILEY: Okay. We'll go back on the record. It's 1:00. We're continuing Case Number 14575. I believe we've just finished with the cross-examination and Commission questions of Alberto Gutierrez. Did we have rebuttal of your witness?

MR. SCOTT: I don't have any further questions of this witness.

CHAIRMAN BAILEY: Okay. Then this witness may be excused, and you may call your second witness.

MR. SCOTT: No other witnesses at this

time. We reserve the right to call one of these gentlemen in rebuttal, if necessary.

CHAIRMAN BAILEY: Well, Ms. Gerholt, do you have an opening statement?

MS. GERHOLT: I do. Madam Chair, Commissioners, the Oil Conservation Division has entered its appearance in this matter not to protest Targa's application but to merely make a few suggestions for you to consider.

Acid gas injection wells are integral to the oil fields in New Mexico and the Division acknowledges that. The Division is asking that you, as Commissioners, consider including in Targa's permit three requirements.

The first is that Targa be required to conduct a test of its choice to determine whether or not a particular zone within the injection interval has more rapidly accepted the injection materials than in another zone.

For example, the test could be conducted after five years or 10 years of injection. By conducting this test and analyzing the data, Targa will have an accurate model and an accurate knowledge of the injection interval.

It will also help the Division. The Division will be able to determine if any wells are in danger or if the injection interval is accepting the materials as presented in the current models.

The Division is also recommending that Targa conduct the mechanical integrity test once a year. Targa's already testified to the fact that they gather pressure data on an hourly basis. They have made this information available to the Division and the Division has reviewed it.

However, the Division is more familiar with MITs, and we have a database which collects information as an MIT, not as an hourly pressure data system, that assists the Division in performing its job of regulations because they're able to then go back through their own database and review the MITs from year to year.

Finally, the Division has recommended that Targa consider having a contingency plan for what happens if the well is off line for an extended period of time. The Division has made this recommendation in order to assure an open and strong communication between Targa and the Division.

Mr. Jones will testify on behalf of the Division today. Mr. Jones is an OCD engineer who has experience with acid gas wells and has specific experience related to Targa's Eunice AGI. He will be able to explain why the Division is asking the Commission for these recommendations.

Again, the Division does not want to halt the permitting of Targa's AGI well, but appears before you today to provide additional information and suggestions for your consideration. Thank you.

At this time, I would now call Mr. Jones.

(One witness sworn.)

WILLIAM JONES

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. GERHOLT:

Q. Good afternoon. Please state your name for the record?

A. William V. Jones.

Q. Where do you work?

A. The Oil Conservation Division.

Q. And how long have you worked for the Oil Conservation Division?

A. Ten years.

Q. And what are your job duties with the Division?

A. I process applications for exceptions to the rules in the Engineering Bureau and serve as a hearing officer on occasion.

Q. You said you worked for the Engineering

Bureau?

A. Yes, ma'am.

Q. Included with your duties in the Engineering Bureau, do you have the opportunity to review acid gas injection wells?

A. I have over the past several years.

Q. Are those applications for AGIs?

A. I look over the C-108 as it comes in.

Q. What's a C-108?

A. The C-108 is the standard form that the Division requires for injection permits. It's intended to be pretty thorough in evaluating the effects of any injection on potential impact to fresh water or movement of fluid out of a zone.

Q. Approximately how many C-108s related to acid gas injection wells have you had the opportunity to review?

A. Probably about seven.

Q. And prior to working for the Division, where were you employed?

A. I worked 20 years with Texaco, Permian Basin and Hobbs, West Texas, Eastern New Mexico for 10 years as a production engineer, reservoir engineer, reserves engineer. And then I was transferred to Denver. I worked 10 years there as explortation/exploration engineer. Then I consulted for a couple of years and came here.

Q. So you have approximately 30, 32 years of experience in engineering?

A. Yes.

Q. And have you had an opportunity to testify previously before the Oil Conservation Commission?

A. Yes, ma'am, I have.

Q. And were you accepted as an expert by the Oil Conservation Commission in regards to engineering?

A. I was.

MS. GERHOLT: Madam Chair, at this time the Division would move Mr. Jones as an expert in engineering?

CHAIRMAN BAILEY: Any objection?

MR. SCOTT: No objection.

CHAIRMAN BAILEY: He's so admitted.

MS. GERHOLT: Thank you.

Q. (By Ms. Gerholt) Have you previously testified before the Commission, specifically about Targa's proposed Eunice AGI well?

A. Yes, I have.

Q. Do you recall approximately when that was?

A. November of 2010.

Q. And for the hearing today, have you had an opportunity to review material submitted by Targa?

A. I have.

Q. Specifically, what materials have you reviewed?

A. I've reviewed the log sweep, the results of the testing as the well was deepened another 300 feet, and it was logged. It was -- they ran pipe and cemented it and then they did their injectivity testing. And I looked also at the production that's been reported for the last -- within the last year.

Q. If I could now draw your attention to OCD Exhibit 1. What is that?

A. We wanted to put this exhibit in to show -- it's sort of a new technology. It looks like Targa has backed up their tracer temperature log with a new logging device. It's -- from what we understand, this is a fiber optics wire line that's in the hole, and it can read different temperatures at different depths and can do a warm-back -- what they call a warm-back analysis. And it's similar to a pressure transient analysis as far as the equations go. It's a temperature decay analysis.

Basically what it's intended to come up with is as they are injecting into the well, it attempts to show the rates going in at different depths in the open hole interval.

Q. This tracer survey was provided to us by Targa?

A. It was.

Q. And what were you able to ascertain from this survey?

A. From the survey, it looks like about 40 percent of the upper interval is taking -- 40 percent of the rate is going into the upper interval. Excuse me.

Q. So a certain depth is accepting a certain amount?

A. Yes, a certain depth is accepting different amounts.

Q. Where is that 40 percent going, you said?

A. Well, I can show it to you on the next slide.

Q. Would Exhibit 2 be a good --

A. It would be.

Q. Let's go to Exhibit 2, then.

A. Okay.

Q. What is Exhibit 2?

A. Exhibit 2 is a log presentation that Targa -- Geolex, on behalf of Targa, graciously submitted -- it's a very good presentation. It shows the -- can I go through the different log traces?

Q. Would you please start from the left and move to the right and tell us about the log traces?

A. If you see on the left side, it says, "Grayburg, San Andres." Go down below that. It says, "Distribution of injection." That is starting at the beginning of the open hole interval, which is shown by the black solid line directly to the right of that.

But you can actually read the different percentages of the overall rate that's going into the different depths. And as you move to the right of that, you got the gamma ray track with the caliper and then you've got the depth track to the right of that. And as you move on across, you've got your resistivity curves. They are on a logarithmic scale, as always .2 of 2,000.

Q. Mr. Jones, if I could interrupt you? This resistivity log, what are you seeing in this log?

A. It shows some effective porosity with the -- basically, the variability in the movement of the resistivity log shows where the effective porosity is in the well. To me, it does, in my opinion.

Q. In your opinion, where is the effective porosity in the well?

A. Based on -- on that log, the effective porosity would be down to about 4,450 feet.

Q. Beginning at where?

A. Beginning at the open hole interval.

Q. Down to 4,450?

A. Yes.

Q. What's the log next to the resistivity log?

A. As you go over to the right, you have your porosity logs, the neutron and the density logs. Of course, the cross plot, like Mr. Dawson pointed out, is the way to look at these. I read somewhere around an effective -- or a total porosity of 11 percent over that upper interval.

Q. And are the porosity log and resistivity log tracking as you would expect them to?

A. They are. I don't want the Commissioners to lose sight of the distribution of injection shown by the tracer survey on the left. They all sort of blend together and support each other.

Q. How do they do that?

A. To me, it shows that about 50 feet of the interval, beginning at 4,350 to 4,400, is taking, in this tracer survey, about 51 percent of the fluid.

Q. Mr. Jones, is that represented on the distribution of injection from the portion of 38.3 percent through the 14.1 percent? Is that where you're looking?

A. Actually, it's on the tracer survey on the left-hand side. Yeah, 38 percent is basically over a 50-foot interval there.

Q. Okay.

A. As you expand that down, you could go to -- 100 feet of the interval is basically coinciding with the tracer survey and the logs show about 100 feet of the interval is taking the majority of the fluid on the tracer survey.

Q. In your opinion, which hundred feet of the interval?

A. 4,350 to 4,450.

Q. Okay. If I can keep your attention on Exhibit 2, and if you will look at the microscan log on Exhibit 2.

A. The microscanner log is shown with the multi-colored tracts over to the right, right beyond the -- where the porosity of the log cores, the sidewall cores are, and it continues on across the log. But that log is capable in some formations of showing primary stress direction in the well, which would coincide with a possible elliptical invasion radius.

Q. Is that what this log is showing?

A. I don't know. It's hard for me to interpret from this. The way to really interpret that log is to go into Schlumberger or Halliburton's offices and get them to process the log for you and look at it right there. Then they can really show you what that log shows.

Q. Okay. But in this log sweep the tracer survey, the resistivity log and the porosity log, were those the main logs that you used in your review?

A. Yes.

Q. Okay. If I can now have you turn to OCD Exhibit Number 3.

A. (Witness complies.)

Q. What is Exhibit Number 3?

A. Exhibit Number 3 is a plot of invasion radius in miles versus years of disposal.

Q. Did you create this graph?

A. Yes.

Q. Why did you create it?

A. To show the variability that can happen with different assumptions. Just one calculation is not really -- doesn't show you the variability that can happen with different, for instance, invasion thickness or -- in this case, that's all that was varied was invading thicknesss.

Q. What were the assumptions you made in this graph?

A. The assumptions made in this graph are effective porosity of 8 percent. That would be equivalent to about total porosity of around 11 percent.

Q. How did you determine an estimated effective porosity of 8 percent?

A. I derated the 11 percent based on an irreducible water saturation.

Q. What was the irreducible water saturation?

A. I used 25 percent.

Q. Why did you use 25?

A. I worked in the San Andres for a long time, and it was rule-of-thumb number that engineers use in San Andres.

Q. Okay. What were the other assumptions that you used in preparing this graph?

A. Another big assumption here is the max disposal rate in barrels per day. I used the same rate that was used by Targa, which equates to liquid rates of 4,075 barrels per day.

But I would point out that if that rate goes up, then that would be different or if it goes down, it would be different. But I did use that constant rate for this whole calculation.

Q. And then I notice on the left-hand corner of this graph, you have a key which depicts injection net thickness; is that correct?

A. Yes.

Q. Could you please tell -- well, why did you decide on the intervals of 50, 100, 150 and 200 feet?

A. The effective thickness that takes that 4,075 barrels was testified to, as I recall, in Mr. Gutierrez's testimony of 3,002 feet.

From my evaluation of the tracer logs and the porosity logs and resistivity logs, it looks like it's thinner than that. The rate, as we know and I know from my experience, is that higher rates do divert into different intervals. But we can see from -- the pressure now in this well is around 800 pounds, injection pressure, after the acid gas injection started. And it didn't start out that way. It started out a lot higher than that.

So obviously, there was some skin damage to the well, around the well. And the acid works on the carbonate, and the bigger pressure drop is always around the wellbore. So you get the wellbore stimulated with the acid and broken down, and it's been my experience that the best zones take the majority of the fluid. And tracer temperature surveys are very good at showing where your production is coming out of or your injection is going into.

Q. Okay. And you've modeled through this graph as a certain zone accepts more of the injection material; is that correct?

A. Yes. From what I see on the log sweep, I just took the thicknesss and I varied them 50 feet and did it from 50 to 200 feet.

Q. And are you in agreement with Mr. Gutierrez that if 302 feet of injection thickness accepts the material, that it should graph below the purple line?

A. Yes.

Q. It would take longer to get to the half-mile radius?

A. To answer your question, yes. I didn't take the 302 and plug it into my equation to see where it arrives on this graph. But I would say that is correct.

Q. And is there anything else that you'd like to point out about this graph to the Commission?

A. It's a sensitivity graph. Basically, it's assuming a uniform radial invasion, not any elliptical invasion. And it basically can be looked at as a spinning top. As you spin a top, the top part of the top usually is bigger than the bottom part. That's what I would envision is happening, at least in this calculation. You can look at it like a wedding cake turned upside down.

MS. GERHOLT: Thank you. Madam Chair, the OCD would move Exhibits 1, 2 and 3 at this time.

CHAIRMAN BAILEY: Any objection?

MR. SCOTT: No objection.

CHAIRMAN BAILEY: They are so admitted.

(OCD Exhibits 1, 2 and 3 are admitted.)

MS. GERHOLT: Thank you.

Q. (By Ms. Gerholt) Mr. Jones, the Division has made three suggestions for the Commission to consider; is that correct?

A. Correct.

Q. According to the Oil Conservation's pre-hearing statement, what is the first suggestion?

A. The first suggestion is to --

Q. Is the Division's first suggestion for Targa to do additional testing after a certain period of time to determine which injection interval is accepting the material?

A. Yes, that's exactly right. That was listed first on the list.

Q. Would you please explain to the Commission why the OCD has made this suggestion?

A. We make this suggestion because we asked -- the Commission asked Targa to run the step-rate test and all this testing before acid gas started last time. Now that acid gas started, you can see from Exhibit 3A of -- Targa's Exhibit 3A, that things have changed in the wellbore. And there may be a difference of opinion between Mr. Gutierrez and myself as to what has changed.

But in my opinion, probably the most porous, permeable interval in the well is now taking the majority of the fluid. So at some point in time, we would ask the Commission to require another injection test or another temperature fallback decay test or some other test that Targa might propose.

Q. Okay. Why has the Division not specified the type of test?

A. Because five years from now, things might be different. There might be more technology. And we don't want to -- we specified a tracer temperature last time, and Targa informed us about these temperature decay logs. So it turns out they worked out pretty good too.

Q. Technology could improve and we don't want Targa to be limited; is that correct?

A. That's correct.

Q. You just have mentioned five years. Is that the time you're suggesting to the Commission for the tests to be run?

A. We routinely do that on injection wells, on big open hole intervals, to require within five years another injection survey to be run.

Q. So that's typical business practice for the Oil Conservation Division?

A. It's been the practice.

Q. Okay. If Targa were to run this test and provide the information to the Division, what would the Division do with it?

A. The Division would look at -- we would re-plot the injection rates for the time between now and the time of the test and look at the test results and get together with Targa to review it and look and see who was correct, which zone was taking the fluid.

Q. Would it help the Division in preventing waste or protecting correlative rights?

A. It would in the sense that it's important that this be not forgotten about for 30 years. Because there are unsubmitted wellbores between a half mile and a mile away from this well. Some of them are still producing from lower intervals. And if something happens to those wells, it could cause waste of oil and gas or cause a correlative rights violation.

Q. To be clear, you said that was between the half-mile and the one-mile radius?

A. Yes.

Q. Because Targa has already addressed the well within that smaller half-mile radius; is that correct?

A. Yes. Within half a mile, there's three wells. And the cement history is a bit sketchy. There was some squeeze work done, but I think they're okay. So between half a mile and one mile, there's 22 wells that penetrate this interval.

Q. The Division's second recommendation is that an MIT be conducted every year. Mr. Gutierrez has testified this morning that he doesn't see that to be an objectionable suggestion. Why has OCD asked that an MIT be conducted once a year?

A. Well, our incidents -- our reporting incidents are cataloged in our database. And it's also a time when the inspector can come out and change the pressure, for instance, on the backside of the well, either increase it or decrease it and let it sit for 30 minutes and see what happens.

Sometimes you find that even if you've got these pressures reported all the time, every hour, which is very good and I want to keep that going, but when you change something and see what happens, then you find out if there is an issue.

Q. Finally, the Division has suggested that the Commission require Targa to have a contingency plan in place if something happens to the well. Why has the Division made this suggestion?

A. Well, the wells are now considered an integral part of the plant, and they're connected with the oil field. And yet the wells are underground injection, so they're covered under the Safe Drinking Water Act, and New Mexico has primacy over that. We've got -- our U.S.C. program needs to be maintained and not impaired by a huge benefit/cost ratio issue, where if a well is shut in, there's a big impact on oil patch even. If they could start the wells back up again, we don't want that to happen.

Q. If I can stop you for a moment, Mr. Jones. So we acknowledge and agree that the hydrogen sulfide contingency plan submitted by Targa is acceptable by the Division and that they've taken all the measures they need to take to have an H2S contingency plan in place; is that correct?

A. An H2S contingency plan is never really approved, I don't believe. It's just accepted as a reasonable plan.

Q. And the OCD has accepted it as a reasonable plan?

A. That's my understanding.

Q. What the Division is asking for here is if there's a mechanical integrity issue with the well, what's Targa going to do; is that correct?

A. That's correct, but that's not all of it. Before that would be how do you determine when a mechanical integrity problem happens?

No matter what mechanical MIT testing interval is set by the Commission, the day after that, something might happen to the well. And if you're reporting hourly pressures and rates, there should be some agreed-upon pressure differential, for instance, with the annulus tubing that can trigger a call to our district office.

Q. Is part of what the Division is asking is for there to be a meeting between the district office and Targa to determine the criteria of pressure differences that could indicate that there's a mechanical integrity issue and that that would lead to an immediate notification to the OCD?

A. That would be the first step, or something similar to that.

Q. Okay. And would notification of producers be also appropriate if that first criteria is met? If something shows that there might be a mechanical integrity issue and the OCD is notified, would you recommend that Targa then notify producers?

A. There's a business relationship obviously between Targa and their producers, and on our end is the URC program, I would say.

Q. And does the Division also hope to take a proactive step in assuring that the Division and Targa can work together to remedy any sort of mechanical integrity situation that occurs?

A. Yes.

Q. Okay. But to be clear, the Division is not requiring any specific sort of second well to be drilled or for, obviously, the SRU is no longer an option, but that the Division is not trying to step into Targa's business plans; is that correct?

A. That's correct.

Q. Okay. As an engineer, do you think that acid gas injection wells are integral to production now?

A. They definitely are.

Q. Why is that?

A. You have to get rid of the acid gas. You have to get rid of H2S, and now you have to get rid of the CO2 somehow by the EPA. Underground injection is recognized by the EPA as a safe way of disposing of waste.

What was the first part of your question?

Q. You've answered the question, Mr. Jones. Has Targa collected and provided the Division with good information?

A. They have done an excellent job of gathering and -- before this, we had no decent logs really in this area to look at, and we have an updated step-rate test based on the new interval.

Obviously, if the interval changes by more perforations, that might need to be changed, including the temperature survey. But they've done an excellent job in gathering information and compiling it, reporting the data, correcting the previous production data. They've done a good job.

Q. If the Commission were to allow Targa to perforate uphole, as they've requested, do you have any suggestions to the Commission about if any surveys should be run?

A. I think if additional interval is perforated that is even more porous and permeable, you could look at it two ways: One way is, you look at that it increases the interval, so you decrease the amount of time it takes to get to half a mile with the plume. What we're looking at here is the plume.

But the other step is -- the other way of looking at it is, if you break in to an interval that has obviously been excellent in the previous completed interval in this well, that it's possible that interval might take preferentially into that zone and go further in a faster amount of time.

Q. And Targa has requested a 1,600 psi; is that correct?

A. That's --

Q. For their MAOP?

A. Yes.

Q. Do you think that's appropriate, or do you have any suggestions for the Commission as in regards to the maximum --

A. If pure water is going into the well, that would be a little bit high. Unfortunately, there's not a huge breakover slope on this step-rate test. So if there were, that means that you exceed the fracture pressure, it goes somewhere in a hurry.

If it's pure water, obviously 1,375 or so -- we usually use a 50-pound safety factor, you know. So I like the idea of a simplified -- that they are proposing here, a simplified pressure number. You asked if 1,600 is good. I would say 1,600 is probably okay.

Q. Okay. Does the Division oppose issuance of an acid gas injection permit to Targa?

A. Not at all.

MS. GERHOLT: Thank you. I pass the witness at this time.

CROSS-EXAMINATION

BY MR. SCOTT:

Q. Mr. Jones, if I could clarify, because I'm not sure I fully understood the third recommendation. Is the recommendation that the permit simply include some requirement that Targa and the Division meet and confer and develop some sort of pressure criteria or other metric that would trigger a notification requirement?

A. Notification requirement would be, I would think, the most important part of that, the meeting, the results of the meeting. The criteria for when the district is notified would be the most important thing.

Q. That would be notification of a potential issue that could lead to a mechanical problem with the well?

A. That would -- actually, that could be it. There is an understanding, and the way our districts operate is, 90-day fix on -- I believe it's 90 days. That's the my testimony here -- 90-days fix.

And the way our district office in Hobbs does it is, if there's a leak in the backside or an MIT problem, the well is shut in immediately and there's 90 days given to fix the well.

So if any exceptions need to be worked out in that as it's going to impact somebody as to what type of MIT problems should be granted an exception to that, I would urge Targa to get with our district office or -- we're here in the setting of the Commission. The Commission could urge that too.

Q. So the recommendation is not that a specific plan be developed that says you're going to take X step to either drill a new well or re-work the existing well or take some other alternative step. It's just simply to notify the Division that there's a potential issue?

A. That would be the first part of the step. If they can work out how to handle the MIT problem as it happens, that would be good too, in advance. Because that would obviously help Targa's business practice.

And we have some very experienced people in Hobbs, and they've seen casing issues on wells. And Targa has a big investment here in their well, and they wouldn't want to lose their well. So I think they need to work with our district.

Q. Has the Division requested or imposed a similar condition in any other acid gas injection well permit that you're aware of?

A. On the fly, we're working on some.

Q. Are there any existing permits that have this condition now that you're aware of?

A. No.

Q. Thank you. There are, at the present, no specific regulations governing the development of acid gas injection wells; correct?

A. Correct.

Q. You spent some time talking about Exhibit 2.

I think you looked at the porosity and resistivity and the tracer logs in particular; correct?

A. Yes, sir.

Q. What distance from the bore hole do those measures go to?

A. The resistivity log probably goes to 90 feet. The porosity logs are obviously extremely close by the well. The FMI is a measurement of the bore hole, so it's right there at the bore hole. The tracer temperature, especially the temperature log, would go further out.

Q. As to the first couple, those are in roughly the immediate vicinity of the bore hole?

A. Yes, sir.

Q. So the indications from those are not going to reflect that the information they're reflecting is uniform and extends out any significant distance from the bore hole?

A. That's exactly correct.

Q. From the data you were looking at, you can't necessarily say whether what you're observing is continuous for some distance or not?

A. We can't.

Q. The request to conduct a further test on the injection after some period, is five years enough time, or would 10 years be a better period of time to allow adjustment of the well and get an indication of conditions?

A. Ten years would have the advantage of getting more rate history in, and I like the fact of keeping track of the rate history. This whole assumption is based on five million a day acid gas and, what, 1,750 of liquids. So if those things change -- so 10 years is not bad. Five years is our normal -- what we usually pick as a time. But 10 years is not bad.

MR. SCOTT: Okay. No further questions.

CHAIRMAN BAILEY: Commissioner Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. So it sounds to me like you'd rather see them test on a yearly basis, MIT tests?

A. Yes, sir. Ideally, some criteria would be set up to where a relationship of the pressures would trigger a call to our district office. And at that time, there would be an MIT run on the well. But yes, we're asking in our application for a one-year formal MIT.

Q. What about the temperature survey? Would you --

A. Temperature survey, the time we were just discussing -- in case the Commission decides what type of test or limits to a temperature survey or a better type of testing, and that would be a temperature decay, the new technology, temperature decay. The time we're applying for is five years because of our standard five-year practice.

You can see from Exhibit 3A of Targa's that the well looks like it's come down and -- stabilize is a hard word to say, but 800 pounds is sure not what it started out at. In other words, the tests could be done next week and I think it would show a lot of difference here, and we would know then if it was a thicker or thinner interval taking the fluid.

Q. So if their request is granted for the upper interval to be perforated to take the injectate, then that graph would considerably change in that regard?

A. It would. The attempt, of course, in the last hearing was to stay away from the top of the San Andres, stay away from that Glorieta down below the San Andres, and they've done that with a lot of expense here.

And they've -- basically, the well that they ended up with may not be quite as good, in my opinion, as the well they had as far as injectivity goes. But I think it's adequate for the amount that they're proposing to put into it.

I looked at the wellbores around in the upper part of the San Andres, and there's 94 wells that are producing or injecting above the San Andres within a mile of this well, and they're older wells. The records are real sketchy about how far down in the San Andres they went to hit that water, and then they plug them back. Obviously, they do the first few wells that way and then the producer's development wells are not much of a danger of that. But the research on 94 wells takes a long time, so I think we're okay on that.

And I hate to say not allow that interval to be injected into. But I would ask the Commission to consider limiting the rate, if they do that, that's gone into this well to the rate that's applied for in this application, which is five million cubic feet a day total acid gas. It's on the brief executive summary of Targa Exhibit 1.

COMMISSIONER DAWSON: No further questions. Thank you.

CHAIRMAN BAILEY: Commissioner Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. This is going to be the third time you hear this same question. On those extra perfs, in your opinion, if you go back to your chart and they really have an injection net thickness of 100 feet, and they would hit that radius at 21 years. If they have a thickness of 150 feet, they would hit it at 30 or 31 years, thereabouts.

I really would like you to just kind of answer yes or no. Do you think they ought to perf and when should they perf if they are to do so?

A. I think they should only perf if they need more -- they're at 800 pounds now. Their maximum pressure limit would probably, as a result of this hearing, go up to close to 1,600, so they don't need it yet. And they may be asking for that blessing to do that right now. But I would say, based on my experience, I would stay out of that zone, because you're going to reach the problem wells faster if you get into that zone.

Q. So delay that decision for a later hearing if they need those perfs?

A. There's a lot that can happen in five or 10 years as far as those wells, and there could be some geophysics or something that could nail down the plume size. But I would ask for it to be denied right now.

Q. My next question, and Chairman Bailey may correct me, but we've done several acid gas hearings, and it seems to me that we've been asking for MIT tests every two years.

A. Yes.

Q. If we want to apply consistency, would having an MIT every two years for this well, along with your contingency of notification from their continuous monitoring, be sufficient?

A. Consistency is very good. I like consistency. And the Commission's decision to go from five years to two years on another well that I know about, resulted in finding out some important things about that well that we wouldn't have found out about maybe for another three years.

So I would stick to the request that we made in this book for this specific well because of the 25 wells that penetrate the San Andres within a mile of it, the porous cement in this area, 94 shallow wells that are above the San Andres in this area.

An MIT failure could get up into that Grayburg waterflood zone. It's a waterflood zone, is what it is. So waterflood zones collapse casing all the time.

Obviously, the contingency plan, if it works out that way, would be very good. But it's not -- it doesn't substitute for an inspector actually going out there and consulting with them. Because our inspectors talk to producers all the time. They look at wells all the time. They have experience in what might be an issue that -- so I would stick with the one year. That's what I would request.

COMMISSIONER BALCH: Those are my questions.

CHAIRMAN BAILEY: I have no questions. Do you have rebuttal on questions that were asked?

MS. GERHOLT: Just a clarification point.

REDIRECT EXAMINATION

BY MS. GERHOLT:

Q. Mr. Jones, in regards to the Division's third request, isn't it true that the Division is requesting that Targa and the OCD meet to set up the criteria for when we would be notified if there's potential mechanical integrity failure; is that correct?

A. Correct.

Q. And that that set up of a criteria could initiate an MIT to be conducted; is that correct?

A. That's correct.

Q. And that this is just our hope for proactive communication between the two agencies?

A. Yes.

MS. GERHOLT: Okay. I have nothing further.

CHAIRMAN BAILEY: You may be excused.

Do you have any other witnesses?

MS. GERHOLT: The Division rests.

MR. SCOTT: May I have one moment to

confer with my witness about whether we're going to address one issue?

CHAIRMAN BAILEY: Sure. We're going to take a few minutes.

MR. SCOTT: Okay. Thank you.

(A discussion was held off the record.)

MR. SCOTT: Madam Chair, we would call Alberto Gutierrez.

CHAIRMAN BAILEY: Mr. Gutierrez, you're still under oath.

REBUTTAL EXAMINATION

BY MR. SCOTT:

Q. Mr. Gutierrez, looking at Exhibit 2 of the OCD, Mr. Jones talked a great deal about the thickness available, and he did an analysis of 50, 100, 150 feet and so on. In particular, he focused on this area of roughly 38, 39 percent shown on the left side of Exhibit 2?

A. Yes, sir.

Q. Can you address Mr. Jones' concerns or comments about that area being a preferential zone for accepting the injectate?

A. Yes. Clearly, that zone is taking a significant portion based on this test that was done. But what I would remind the Commission is that actually, if you look at this same OCD Exhibit 2, that really the zone between about 4,250 and 4,500 is what is taking the bulk of the flow. That would be about 250 feet of the zone. Then there's a zone below that that is taking very little or no flow and a zone at the bottom that's taking another 11 or 12 percent.

So I think that the -- while I would agree with Mr. Jones that, you know, based on his assumptions, which I think are reasonable assumptions in the context of the rate and the porosity -- there's no disagreement there -- but that I don't believe that at least the upper two curves that are shown on here, the 50- or 100-foot curves, really are representative of what we're seeing when you consider the distance away from the wellbore.

I think it's really -- our belief is that that flow is spread out over about 300 feet. But you know, I would agree there is some potential for that to vary. I think 200 feet is the absolute minimum that I would feel comfortable assuming.

But the most important thing that I would say is that, based on the characteristics of the San Andres, once you move away from that wellbore, it's not likely that that flow is going to stay continuous in those zones because it is a massive carbonate that has been diagenetically altered and that flow tends to even out as you get further away from the well. Or there may be other zones that may take it more preferentially at other distances away from the well.

So I would just ask the Commission to keep that in mind, and that I think what we're proposing is a very reasonable time limit for the permit under these conditions.

MR. SCOTT: All right. Thank you.

CHAIRMAN BAILEY: Ms. Gerholt?

MS. GERHOLT: No questions.

CHAIRMAN BAILEY: Commissioner Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. On Exhibit 2, the 38.3 percent curve on the distribution of injection there --

A. Yes, sir.

Q. -- that zone there, is that the zone -- would that correlate to the zone that he spoke of that's producing from the 90-plus wells in the area?

A. Absolutely not. That zone would be about 400 feet below that zone.

If you look on Exhibit 2, the zone that Mr. Jones was referring to is the Grayburg, which is above -- it's at roughly about 4,000 feet in this area, so we're way below that.

As a matter of fact, as Mr. Jones testified, I think that's the reason why the Division originally wanted their injection restricted to the area below 4,250.

COMMISSIONER DAWSON: No further questions. Thank you.

COMMISSIONER BALCH: I have no questions.

CHAIRMAN BAILEY: I have none.

You may be excused.

Do you rest your case?

MR. SCOTT: We do.

CHAIRMAN BAILEY: Do you rest your case?

MS. GERHOLT: We do, Madam Chair.

CHAIRMAN BAILEY: Do I hear a motion to go into executive session in accordance with New Mexico Statute 10-15-1 and the Oil Conservation Commission resolution on open meetings?

COMMISSIONER DAWSON: I make that motion.

CHAIRMAN BAILEY: Do I hear a second?

COMMISSIONER BALCH: I'll second.

CHAIRMAN BAILEY: All those in favor?

We will go into executive session to deliberate and we will come back out and announce our decision and ask the attorneys to develop draft orders for use of the Commission Counsel.

(Whereupon the Commission went into executive session.)

CHAIRMAN BAILEY: Do I hear a motion to go back on the record?

COMMISSIONER DAWSON: I'll motion.

COMMISSIONER BALCH: I'll second.

CHAIRMAN BAILEY: All those in favor?

The only topic that was discussed during our executive session was this case, and I would ask our Commission Counsel to outline the decision and the requests of the attorneys.

MR. BRANCARD: Thank you, Madam Chair. Case 14575, Order R-12809-C, required Targa to come back to the Commission with information on its wells. The Commission finds that Targa has presented that information as required by the order.

Targa has requested several matters from the Commission: To issue a long-term permit of 30 years for the well for acid gas injection; to increase the pressure, allowable pressure; and to increase the perforation zone.

The Commission has determined that a permit for 30 years will be issued. The permit will have a 10-year review period along with the 30-year term, and I'll explain a little more about that later.

The pressure as requested by Targa can be increased to a maximum of 1,600 psi. We understand that the issue was never raised, but the volume number that is in the permit now remains the same.

Targa's request to increase the perforation zone is denied based on insufficient data at this point to support that increase.

The Division has requested a number of conditions to be placed in the order. The first condition was to require further testing at some intervals to determine whether the distribution of injection profile that is shown in several of the charts presented by Targa can be further verified in the future.

The Commission agrees that such tests should occur every 10 years. It is to precede the review that occurs during the 10-year review and will be based on that testing. Again, as the Division has noted, if the tests -- you have a test today that works. Ten years from now, if you have a better test 10 years from now to determine that profile of the distribution of injection, then please work with the Division to agree on that.

Mechanical integrity tests will be annual for this permit due to the unique conditions on a number of surrounding wells in this area.

The Division has requested that it work with Targa on a contingency plan, and the Commission agrees that such plan should be worked on. The plan will focus on questions of potential mechanical failure and what is the backup for Targa in that case, when to notify the Division of potential concerns, when to notify producers, and under what conditions OCD may require an additional MIT at the location. Have I covered all the --

CHAIRMAN BAILEY: Yes, that's everything in my notes. Thank you. We ask that the draft orders be submitted three weeks from today.

Are there any other topics on this case?

MS. GERHOLT: Not from the Division.

MR. SCOTT: No. Thank you.

CHAIRMAN BAILEY: Then we'll go on to our next order of business, which has to do with the Oil Conservation Division's application for re-hearing of Rule Amendment 19.15.14.8 in Case Number 14744.

Call for appearances.

MR. SCOTT: Gabrielle Gerholt on behalf of the Division.

CHAIRMAN BAILEY: Do you have any witnesses?

MS. GERHOLT: I do not.

MR. FELDEWERT: Madam Chair, Michael Feldewert appearing on behalf of the New Mexico Oil & Gas Association, and we have no witnesses.

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on February 23, 2012, proceedings in the above captioned case were taken before me and that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with any of the parties or attorneys in this case and that I have no interest whatsoever in the final disposition of this case in any court.

WITNESS MY HAND this 7th day of March, 2012.

Jacqueline R. Lujan

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2012