STATE OF NEW MEXICO

DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES

OIL CONSERVATION COMMISSION

APPLICATION OF OIL CONSERVATION DIVISION TO ADOPT 19.15.27 NMAC AND D19.15.28 NMAC, AND TO AMEND 19.15.7 NMAC, 19.15.18 NMAC, AND 19.15.19 NMAC; STATEWIDE

CASE NO. 21528

REPORTER'S VIRTUAL TRANSCRIPT OF PROCEEDINGS

DAY 6

January 11, 2021

8:30 a.m.

Hearing Officer Felicia Orth

Chairwoman Sandoval

Commissioner Engler

Commissioner Kessler

REPORTED BY: PAUL BACA, CCR #112
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Also Present:

Dylan Rose-Coss Tech Support

John Garcia Tech Support

Florene Davidson OCC Support

I N D E X

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HEARING OFFICER ORTH: All right. Good morning, my name is Felicia Orth. I am a Hearing Officer appointed by the Oil Conservation Commission to conduct a hearing in this matter in Case 21528.

We are on our sixth day of the hearing. We broke Friday, January 8th, the Chairwoman of the Commission was finishing her examination of NMOGA's witness, Mr. Smitherman.

Madam Chair, whenever you are ready.

CHAIRWOMAN SANDOVAL: All right. Thank you.

JOHN SMITHERMAN,

after having been previously duly sworn under oath, was questioned and testified further as follows:

EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. All right. I just have a handful of questions. Most are different than Friday, a handful are on at least similar topics.

I think before diving into some of the more technical questions, one of the things that I was left somewhat confused and I would like some clarification is I could not figure out throughout your testimony exactly who or what you were representing.

It seems like we waffled back and forth from, "I am representing NMOGA and this 80-people panel," to, "I am representing myself John Smitherman and my experience from opening up one company throughout my career."

Which was it or both, but it was quite confusing for me because it sort of went all over the map.

A. Good morning, Madam Chair.

Q. Good morning.

A. I'm here as a representative of NMOGA, and actually Independent Purchasers of New Mexico, associated from New Mexico, is also a part of our team that analyzed and created, suggested modifications to this rule, so in one sense I am representing IPNM as well.

And I guess that somewhat cannot separate my experience to explain things, as I represent these different organizations. So I guess it is firmly that I am representing NMOGA, but my experience colors my ability to explain things.

MR. FELDEWERT: Madam Chair, if I may interrupt. This is Michael Feldewert.

The other point is, as you know, from our prehearing statement, Mr. Smitherman is a petroleum

engineer who has been qualified by Federal and State courts as an expert witness in petroleum engineering in oil and gas operations.

So at the request of the Commission we did not necessarily qualify him as a witness but he is here to provide his expertise as a petroleum engineer with 40 years of experience to the issues that have been raised by this rulemaking proceeding.

CHAIRWOMAN SANDOVAL: All right. That is helpful. It was just somewhat confusing throughout.

COMMISSIONER KESSLER: I have a few questions.

CHAIRWOMAN SANDOVAL: Yeah, go ahead.

COMMISSIONER KESSLER: Mr. Smitherman and Mr. Feldewert, I have heard representations that Mr. Smitherman is also speaking on behalf of IPANM. I don't see that anywhere in the prehearing statement. Is there somewhere else I should look to confirm that?

MR. FELDEWERT: Commissioner Kessler, Mr. Smitherman, first off, was named as an expert witness to provide technical testimony on behalf of NMOGA's proposed modifications. I think his testimony was beginning that not only is it NMOGA's proposed modifications, but they have been also able

to provide IPA New Mexico's opinions on this so we would not have an additional party with additional witnesses.

COMMISSIONER KESSLER: Thank you, Mr. Feldewert. I understand that. I guess what I'm asking, I saw that IPANM submitted incomings. I had not seen any kind of entry of appearance or confirmation that NMOGA and IPANM were submitting a joint proposal, and that is what I wanted to confirm.

MR. FELDEWERT: You are correct. The modifications were submitted by New Mexico Oil and Gas Association. IPA New Mexico did submit comments, but really by way of clarification. Since the filings, we have been able to essentially consolidate our position and avoid having an additional party in the case.

But technically, you are right, Mr. Smitherman is named as a witness, as a technical witness for the New Mexico Oil and Gas Association.

COMMISSIONER KESSLER: Okay. Thank you.

CHAIRWOMAN SANDOVAL: Just before we keep going, Mr. Baca, could you mute, please. There is like a lot of feedback coming from you.

Thank you.

Q. (By Chairwoman Sandoval) This may be for somebody else. There was testimony on Friday or Thursday, whatever the day was, because there was talk of -- so with the emergency and the four hours or eight hours or whatever time frame ends up there, operators who have -- and I think we got caught up on the word "SCADA."

I want to take the word "SCADA" out of this. I think we got caught up on that intricacy. There are operators who have the ability to shut-in their wells remotely.

What I would like to understand better is, is there any sort of understanding as to what percentage that may be who can versus who can't? Is it one operator can shut-in all of their wells remotely or maybe 15 percent of them or some operator can't at all, or what is mixed here? Because I think that is really important as we are trying to determine what the time limit is or if there is one in an emergency definition.

Can you provide any more information on that?

A. I certainly understand your question. I have got to say we didn't -- we didn't explore which operators do and which operators don't have that

capability, so I don't think I should speculate on it. I can tell you my experience and probably the only thing I think would be relied on, if that would be helpful.

Q. Yeah. I mean, that is helpful. This is where I get confused with your testimony. A lot of the technical stuff you are relying on your experience but you have said in your testimony you are representing this 80-member crew, and so I am sort of expecting you to be able to provide me with an overview of what these 80 members or people or groups, whatever, can do, but all I am getting is your own experience.

A. Yes, and I understand that. I guess the challenge I have is there are questions that are coming up in this hearing that perhaps we didn't anticipate and didn't have a discussion amongst this bigger team, so maybe that is a flaw from my side that we didn't think of every possible question that could come up. But maybe we should have tried harder, I don't know.

So when I don't have that information I can offer you my personal experiences, if that is helpful.

Q. That would be helpful, sure.

A. My personal experiences are that we -- we were a pretty large company. We were a top, we probably ranked 13th or 14th largest oil producer in the States, so we were a significant player in Southeast New Mexico. We had nothing in Northwest New Mexico.

And we -- I think we had a relatively sophisticated operation for a company that size and we had very, very little capability to actually affect something remote control. I know particularly, I remember very clearly even testing the ability for us to be able to affect a pump or valve at a saltwater disposal station. We wanted to do that because of its particular nature, but I don't recall that we had -- let me put it this way, I recall that we didn't have a very large ability outside of that to shut wells that -- we probably had a few, but we didn't have very much. And some of the conversation about that was, well, why would you want to have that.

Well, at the time we were thinking of things like some kind of a fire at a facility and maybe you want to be able to shut things down because of something like that. From our standpoint, from my personal standpoint, and I do

think I can represent the group. They would prefer, the operators would prefer to send a human to deal with something like an upset from a midstream, because it is not just shut everything in. That is maybe not the best response. We may be able to redirect gas to different outlets and some of these, especially some of the larger companies, and maybe not just the larger companies, have multiple outlets and they do that to be able to have more reliable gas takeaway.

That is a good thing that they have been able to establish that. So if they could get out to the field and redirect gas from Gatherer A, who has an upset, to Gatherer B who can get some gas into that line, that means they will get it produced and reduce that flaring or venting quickly, but it takes a human being.

To me it is always better to have a human being out there making decisions like that from coordinating with the midstream companies to make the best decision.

Q. And you believe eight hours is a more feasible time frame for that than four?

A. I do. You know, there is midstream upsets that we can respond to in four, but there is

probably quite a few that will take somewhere between four and eight. There is going to be some that are longer than eight, but we thought that life in eight is a reasonable compromise, if you will, to be able to address most of them safely and effectively.

Q. Do you have any idea -- so in the new Part 28, I don't have the citation, but it basically requires, right, for operator, midstream operators, to prenotify anyone two weeks ahead of time any sort of maintenance, known upset in their system.

Do you have any sort of understanding of what the percentage might be of situations where it is all preplanned and like, you know, production companies are going to know two weeks ahead of time on this date we need to route to other place, et cetera, plan ahead all of those things versus like something hits the fan and we have got to go into an emergency situation because Compressor Station A is totally down and we now can't go into the outlet.

Is there any understanding of what their frequency is of like this is preplanned versus things happened that are outside of the control?

A. Sure. Let's talk about that.

First of all, I view this as very separate

issues. We viewed it, midstream companies have historically been able to notify their upstream customers where they have planned outages. That is not new, that is not unusual, and this rule puts in some quantification of that, which is a good thing. It calls for 14 days as the standard, if you will, for notifying for scheduled events. And we think that that is ample, so we support that.

And, however, there is a, I guess a normal body of maintenance and turnaround and additions and, in essence, anything that is going to cause an upset to the flow, there is a bucket of those things.

We think that with the Division's language in the rule is proper, it is adequate. It gives upstreamers plenty of time to schedule if they are going to reroute, schedule if they are going to shut wells down, maybe schedule their own maintenance during that same period of time. That is really helpful to be able to say if you are down I am also going to be down too, so it makes it more effective and efficient. Let's set that aside for a moment.

This other body of unexpected things that the four hours or eight hours addresses. These are the things that you didn't schedule because they

happened to you. They are either something failed that you didn't expect, a weather event that came in that caused things to fail that you didn't expect. There was no ability at all to know it was coming and, therefore, no ability to preplan for those.

I see that the rule addresses those separately and that is the piece that we are saying it is the upstream -- and by the way, we appreciate the fact that the rule indicates that that midstream gas gatherer has got a requirement to notify. They typically do notify anyway, by the way, and it allows us as soon as we know, either because of our remote monitoring systems or because we have been notified, it allows us to send somebody out to the location to respond to it. That is the piece that we would like to have a little more time on.

How many of those, let me, they are not infrequent. They are not every day, but they are not infrequent that something like that does happen, especially the larger your company is and the bigger your footprint is, the more frequent that is going to be because you are connected to more gas gatherers or more sections of the gas gathering system that could have an impact on that.

Q. Okay. I wrote down on a different topic

in quotes that there is a common understanding of venting and I have a bunch of question marks under that.

What do you mean by there is a common understanding of venting? I would like to hear what that means in your mind because I don't know what the common understanding of venting is. So I am concerned if there is some reliance on some of the proposal on this "common understanding of venting" that is actually not common?

A. I guess I don't remember exactly where I testified to that. Can you help me? Did you --

Q. I am trying to recall. I think it was when there were eliminations of some of the categories on some of the reporting categories as I believe were the discussion with counsel and how some of those reporting categories were eliminated because it was not a common understanding of venting.

MR. FELDEWERT: I object, Madam Chair. I think it was also Mr. Smitherman's, as I recall, when we were discussing the definition of venting.

CHAIRWOMAN SANDOVAL: It may have been and the high and low pressure stuff, too, I believe. It may have been a couple of places.

MR. FELDEWERT: I think there was an exhibit where we showed the Colorado definition of venting. I believe that is where you came up with that.

CHAIRWOMAN SANDOVAL: Thank you.

A. Okay. That is kind of what I was thinking that you were headed. And when you look at the definition of, if you would, the definition of venting and flaring that Colorado uses that we are suggesting, it is more -- in part, it is recognizing by example some actual releases in the field that Colorado has recognized as not venting.

So it is somewhat of a definition by exception, but it tries to be clear in enumerating those particular elements and I would be happy to go back to that exhibit and kind of look at that again.

Q. (By Chairwoman Sandoval) I think it is C9.

A. Okay. In fact, it specifically talks about emissions of gas from the devices such as, and that is maybe the key words there, pneumatic devices pneumatic pumps that are designed to emit as part of mobile operations.

There are a lot -- there is a body of equipment that is designed to emit and these are

typically -- all of these are typically the low pressure sources that Colorado has recognized in their definition as not venting. So if you take those away, if you had a well that you were -- that you just -- that the operator decided that they wanted to, I don't know why you do this, but you would basically take the full gas production and open it up from a higher pressure separator like 125-payload per pressure separator and send it to the -- to a vent system, that would be venting. If you did that on purpose that would be venting?

But that is a very, very different type of circumstance that all of these low pressure sources that we are trying to recognize as Colorado has as not venting.

So it is more of a definition by example and perhaps, perhaps there is a pressure that we could use to help define those low pressure sources.

The API does recognize low pressure vessel. They have established 15 psig as a low pressure vessel. We didn't necessarily put that in the rule, but at least it might help our conversations here.

Q. I mean, but doesn't the Division's rule sort of help to address that without just explicitly

excluding? I mean, they don't "count against you" in the rule.

Now if its malfunctioning, which does happen, then that would count, but I mean, isn't that in a lot of ways already accounted for here?

A. Yes. There is certainly ways, different ways to look at it and, you know, if these low pressure sources aren't counted against us, that is, that helps. What we -- what we thought would be most helpful is to focus on those sources that you could reliably and accurately measure and record, because those were very -- we thought very clear. And, in fact, we thought long and hard on all the different sources and therefore categories that that might represent and we named every one that we could think of.

So we -- we thought perhaps following the same -- and by the way, let me point something out. The Division has looked across many different examples. They have looked at different States, they have looked at even some in Canada and they have taken some of those practices into this rule. They have looked at some of those practices that have exceeded them. 98 percent does that include exceedance from anywhere we looked at and it looked

at some of the practices and it left them behind because it didn't feel like it was going to fit New Mexico rules.

So this one that they looked to, that we looked to Colorado seemed to be a good way to, in essence, give the Division accurate information from high pressure sources that you really could measure and record with good accuracy and simply not report those pieces, those sources that you could not measure with sufficient accuracy for production accounting purposes. So that is the whole construct that we are looking at.

Q. One of those was, I don't remember the citation again, tanks, right, uncontrolled storage tanks?

A. Yes.

Q. That one perplexes me a little bit. Can you elaborate on why you want to eliminate that?

I 100 percent understand that those can be permanent to vent by the Environment Department, but we are not the Environment Department here. I think we have made allowances for those types of things within the rule.

There are countless modeling programs where you can model the emissions from tanks, things

such as simple as EP Tanks, you have HYSYS, you have ProMax, you have a suite of tank software that can model the emissions coming out of a tank, so that one is quite perplexing to me.

Can you elaborate on why you think it is impossible or not feasible to get some sort of accurate measurement, measurement is the wrong word, estimate of what would be coming out of there?

A. I think you have asked the right question because certainly measurement would be impossible to get one. You're focused on some other type of model than estimate.

And I guess my best answer there is that the -- from our perspective the -- if you have got an uncontrolled tank, it is at the end of the line, those volumes that would come to that tank are not economically capturable, so they don't represent waste. They are downstream of, in essence, enough separation equipment with a low enough flash that even the volumes are below what the NMED would suggest controlling in some way that is why you are allowed to have an uncontrolled tank.

You know, those -- those can be estimated but you tend to have numbers that are somewhat theoretical, in essence, that don't necessarily

reflect the actual parameters that actually occurred in a given day. What was the actual flow rates, what were the actual temperatures, those things that you put in HYSYS and TANKS to be able to get -- and by the way, I am not an expert on either of those two modeling programs, but I think I know enough to be conversant about them. If I misstate something I will let you know. I'm just letting you know I am not an expert in that particular area. But I know the concept and I just think that it would be somewhat of an enormous task to be able to come up with anything that represented an accurate measurement of that.

MR. FELDEWERT: Madam Chair, this is Michael Feldewert. Just so you know, we do have a witness that is going to address your question.

CHAIRWOMAN SANDOVAL: Okay. That would be good because I am finding this answer not fully satisfying. You know, I guess my concern and hopefully the next, whenever -- wait, who is the witness so I can --

MR. FELDEWERT: It is going to be David Greeves and then Mike Smith is also familiar with this.

CHAIRWOMAN SANDOVAL: Okay. I mean, my

concern here is that modeling in some of these softwares is what you design entire facilities off of, so it is a little alarming to me that it wouldn't be good enough to run a tank model going even further. These are the modeling softwares that you permit facilities with, that you do greenhouse gas reporting with, which you have to report tanks. I believe, I can't 100 percent recall productions but I know for mid-streaming you have for, jeez, ages, and so I -- like it is very concerning to me these statements. So it would be very helpful to hear, hear some more information on that later. All right. Sort of moving on.

Q. (By Chairwoman Sandoval) All right. I think it's in your proposal in the NMOGA Proposal 278, B1.

A. Yes, I am there.

Q. All right. So I think you guys are wanting to do -- so you are wanting to strike "technically feasible" and go with "reasonably practical" because you -- just elaborate a little bit on that for me, please.

A. Certainly. It somewhat gets back to this same issue that even other witnesses have talked about when you get a little more absolute.

Technically feasible can be viewed as being pretty darn absolute, that maybe you have got things that can be technically feasible but enormously expensive, and so we were concerned that that would result in, I will just use the word an unreasonable interpretation of this rule.

So if you would use the term reasonably practical using best industry practices and control technologies, we feel like that that would be effective in accomplishing what the Division was trying to accomplish here without the possibility of someone trying to take it, if you will, too far with technically feasible.

My testimony is technically feasible. It is pretty darn unreasonable and practical. So that was really the objective there is to try to make it a little more, a little better understanding.

Q. Do you think that opens the door for, I think as you have said before, mischief?

A. Well, I think that I would be happy to rely on the Division's interpretation of reasonable.

Q. But I don't think any -- correct me if I am wrong here -- I don't think any of these -- these aren't necessarily going to the Division for approval.

Now somebody could probably take something to hearing, but the Division isn't approving each and every reasonably practicable thing, so how would the Division know?

A. Well, I guess how would they know if someone was doing something that was technically feasible? So I viewed this as the Division does have the ability and the history of inspecting circumstances in the field. They do typically go, especially on drilling rigs, we expect to see them on casing jobs, cement jobs, you know, quite often, so my perspective, my personal perspective is we didn't talk about this particular thing.

Our expectation was that the Division would either on their own accord see something that they didn't think was right or we have got citizens that report to the Division and the Division may respond.

So we had no expectation either that something was going to be approved or we expected it, that the Division was going to look at an operation and say, "Hey, that is not reasonable."

We didn't want that to go to, "Well, you didn't do something that was technically feasible." I just, again, think that that is more practical. I

used the word in defining it. It just seems to me that it would be a more clear interpretation. It can't be somewhat used to mischief, I don't want to use that term. It just seems like a more appropriate term.

Q. Now, do you think that there are some ways, though, that people could really begin to pull cost into it? I understand that cost is a factor in the sense of -- I guess, let me just start with the first statement or question.

Don't you think that that could really start to circumvent things and become a loophole because people would start to pull costs into it and use that to justify them not doing something?

A. Well, let's think about this particular passage. When you think about somewhat, sometimes the issue of cost is a cost/benefit type of analysis; isn't that correct? So that would somewhat imply that these volumes that could be released during drilling operations have to be -- the cost would have to be outweighed by some kind of gas capture that you could then get revenues from, some kind of a cost/benefit. But that is not what happens in a drilling operation.

These gases are going to be released

either by venting or flaring but -- and that decision is typically made on safety, their safety reference. So if costs come into this conversation it is really going to be something that is, quite frankly, maybe obvious to many people that the cost is enormous and impracticable and unreasonable as opposed to something that is normally expected in the workplace. So for someone to come in saying, "I can't do that," and everybody else in the industry is doing it, that is unreasonable on their part. If you need to spend a little money to do what is reasonable and what is normal, then it is unreasonable not to.

Q. Okay. Do you think it is reasonable that companies may have to spend money to adequately manage their waste?

A. That is a pretty big question. Can you maybe narrow it down to something that is a little more -- I have a hard time answering that in such a big broad general form.

Q. I am trying to think how to restate that.

I mean, do you think that it is reasonable, likely, that a company in order to comply with the rule and manage their waste appropriately will have to spend money, basically

that option in order to adequately manage their waste it might be more expensive than not?

A. It seems like a statement that it might be more expensive than not, I am not sure.

Q. Does it -- no, I think it is a question. I am asking you, does it make sense to you? Do you think it is reasonable that in order to adequately manage your waste, or your, you know, a company's, using "your" in like a broad sense, a company might have to spend more money than if they were not adequately managing their waste.

Does that seem reasonable to you?

A. I guess my answer is it is a bit of a hypothetical, but I can't disagree with you that sometimes that we might expect that a company would have to -- I think the word that you used was "pay money to deal with waste."

I think that there is an expectation of that in some circumstances. I can't deny that.

Q. Do you have any concern that your language "reasonably practicable" might pull in that cost piece of it in a way that is negative or in a way where people are basically trying to justify not managing their waste because of costs, because it is too expensive?

A. I understand your question and I think I can answer it very definitively but not in this section. I think that that is not a factor.

Q. Okay. Are you familiar with OCD Rules Part 35 and Part 36? I can read you the titles if that would help.

A. I am probably not familiar enough with them. I don't even know which one 35 and 36 are.

Q. 35 is titled Waste Disposal.

36 is titled Surface Waste Management Facilities.

A. No, ma'am, I am not familiar with those.

Q. So do you agree that it is already common practice for the industry to have to sometimes pay to adequately dispose and manage their waste?

A. Yes, I am familiar with that.

Q. Okay. Thank you.

So we talked a little bit last week about AVO. And you said that the issue is not the -- well, that is awkward. That is an awkward statement.

You said the issue is basically recordkeeping, it is not that the people are not already out there on site. Do you have a solution for that? Is there a solution that you would

propose in order to make AVO more manageable?

A. I think the solution that we are offering, our solution, our proposed modification to recognize that the act of doing a -- I will call it official AVO. Let's define that.

We have got lease operators that are on location that are observing, they are hearing, and they are smelling many times every day. So that part of it is there is a little bit of conversation to have around that compared to official AVO. But let's focus, if you will, on the administrative burden. It seems like that, and you pointed me out, you were right, I may have used the word "no benefit."

There is little benefit from doing an AVO weekly versus doing an AVO monthly from an actual discovery of releases state corps. There is a big difference in the administrative burden between weekly and monthly from that aspect of it. It isn't just -- quite frankly, it is not just a, you know, Big Chief tablet with three boxes, did I smell something, did I hear something, did I hear something? Did I say that right? And it actually will have to be a little more complicated than that based on just the words in the rule.

They point to things that it is a little more complicated inspection, if you will, than simply walking around and listening and hearing and seeing. But the concept is then that has got to go into an administrative process. There is a training aspect of it, there is a documentation aspect of it, there is a QC aspect of it. Somebody is going to have to look to make sure that every well, every facility that is on the list actually got paper in, was it done right and then there is some recordkeeping points.

So what our proposal is, is to do exactly what you are asking for but simply do it on a little less frequent basis.

Q. I think, was your proposal once a month?

A. Well, it was once a month on what I'm going to call regular wells with a little bit of flexibility on some of the low volume producers. The monthly difference is you go from weekly, which is 52 times a year, to monthly, which is 12, that is a big factor difference in the administrative burden.

Q. Would two weeks not be a more reasonable jump from one week rather than one week to every month, to one week to two weeks, or do you think

that two weeks would still be too much burden?

A. Well, I quite frankly appreciate you at least being open-minded to something other than weekly. Clearly we thought that a monthly process would be fine. We didn't talk about two weeks, quite frankly, basically the big difference, the big jump from 52 to 12 is a big jump in administrative work, especially literally almost every well that is a normal producing well you are going to have a lease operator out there, seeing, smelling, hearing, virtually every day.

So you are not getting that much more physical difference in looking for things, you are getting documentation that is on site. So we didn't see much physical benefit. There is a little. When you actually have to write it down, you are probably looking a little more carefully especially when you follow these rules there are some things that we might not look at as carefully every day. So you are getting a little bit of a benefit. You are just trying to find that balance between benefit and administrative work.

Q. Okay.

COMMISSIONER ENGLER: Can I ask a follow-up on some of that?

CHAIRWOMAN SANDOVAL: Yeah, go ahead.

COMMISSIONER ENGLER: Good morning, Mr. Smitherman.

THE WITNESS: Good morning, sir.

COMMISSIONER ENGLER: I guess I am trying to make sure I understand. Your lease operator, they are still making their rounds every day or every week, correct?

THE WITNESS: Yes, they are. Generally speaking my expectation of most wells that are not low, low producers that someone is going by there every day is not too often, perhaps every couple of days is known.

COMMISSIONER ENGLER: What I recall and, of course, I am a little older now, but you used to do the other pump sheets usually depending on the type of well frequently, at least every other day, so they are still making the rounds. Do they do this -- again get me up to date. We used to do it all on sheets. Are they doing it on a tablet now or are they still all doing it on paper?

THE WITNESS: Good morning, by the way. I think you will -- I am a little older, too, by the way, you might have noticed that.

I think that you will probably find that

there is still a mix, that maybe some of your former companies have converted over to some kind of an electronic data capture and others are still using paper.

COMMISSIONER ENGLER: So they are making the rounds -- so if I understand correctly, you know, the Division is asking weekly, you are asking monthly, and it has to do with providing the, whatever the report requests that it's volume we are looking at, this change in frequency; is that correct?

THE WITNESS: Yes, sir. It's not -- there is an expectation, if you will, for companies to send lease operators to see their facilities. And there is an expectation for those lease operators to look and to make sure that things are not normal. That is one of the main reasons they were there, right, is to make sure production is optimized and that costs are optimized. If we are spilling something is very, very costly. So looking for leaks and looking for things like that is definitely part of their job description.

So they are going to do that. They are not necessarily going to fill out an AVO checklist, if you will. And if you look at the rule itself,

there is some implications or maybe some suggestions in there of the type of equipment that needs to be looked at. It is a little more detailed when you start looking at where the seals are cracked or some of the fine points there, that is probably beyond what you would expect a lease operator to look at every day. You do look for leaks. It is relatively easy to see, especially when you have liquids.

So the difference really is not as much from that lease operator, there is some because he has got to spend a little more time going through maybe a methodical type of look to make sure that checklist is filled out properly. Then it is the administrative burden of making sure all of those records are properly checked. It just doesn't seem the benefit and I got to say it is -- well, I will just say it this way. The benefit does not seem to be proportionate to the administrative burden at a weekly level. We just feel like there is a better balance than likely.

COMMISSIONER ENGLER: I guess one last question on that. Do you think, you know, if you did it weekly you have some checklists and you had this weekly data and it showed that the operator in industry was monitoring on a weekly basis and

showing repeatedly no leaks or no emissions, that maybe the benefit would be a demonstration of how well the industry is monitoring and succeeding?

THE WITNESS: I can see that, maybe I could even argue the -- I don't want to be argumentative, but if you did it monthly and found a relatively low frequency it seems to me that might convey the same message.

COMMISSIONER ENGLER: That is not argumentative. I understand it.

Thank you, Madam Chair.

THE WITNESS: Thank you, sir.

CHAIRWOMAN SANDOVAL: No problem, Dr. Engler.

Q (By Chairwoman Sandoval) Okay. And NMOGA's -- your proposal, it is on Page 15 of the white book, I think at 6?

A. Yes.

Q. I guess my question is, so as I think you have stated multiple times, a lot of the sort of low pressure things tend to be the ones that are the -- well, you stated the low pressure is hard to measure. And most of the beneficial use categories, such as the pneumatics, et cetera, are in that bucket.

Do you not think that 5 would cover 6? So 5 says, "Where metering is not practicable such as low flurry or low pressure, venting and flaring." your proposal says, "During drilling operations the operator may estimate the volume of vented or flared natural gas."

Do you not think that 5 would cover 6, the proposed 6, and if not, can you elaborate on why you think the addition of 6 is necessary? Do you see where I am talking about?

A. Yes, I do. Just a little bit of thought to that question. I can see your point that the beneficial use gas is typically, I will call it low, low volumes, but not all. And I guess there are opportunities for actually measuring some of those beneficial use gases.

Let's take the example of compressor fuel. That is beneficial use and I guess that doesn't really hit the mark.

Let's talk about like heater, treater, burner. That is a low volume, low pressure, low volume, consumption of gas that we have got, number one, a better understanding of its consumption when operating properly.

I think that beneficial use gas is

recorded separately in our reporting system. So perhaps, and I have got to say, we didn't ask this particular question of whether 5 would cover 6. So I am just kind of thinking it through that perhaps it is because we are reporting those beneficial use gases separately. And I guess beyond that, I am just going to have to maybe say I don't know. I see your point. I am not trying to evade your question as much as I just don't know.

MR. FELDEWERT: Madam Chair, this is Michael Feldewert. We do have a witness on these types of measurement issues.

CHAIRWOMAN SANDOVAL: Which one is that?

MR. FELDEWERT: Mr. David Greeves.

CHAIRWOMAN SANDOVAL: Okay.

Q (By Chairwoman Sandoval) All right. Let's go to NMOGA's proposal that is on Page 17, 27G17, little I, 7.

A. Yes, I am there.

Q. It is the addition. I just want to better understand what the intent of adding this?

A. Certainly. This relates to the body in C-129, which is an episodic release of gas. And it -- the original language basically said give us the cause and nature of venting and flaring.

Q. Right.

A. We have seen, if you will, not particularly structured and since we were already recommending these categories for reporting, we thought that it would be helpful to not only the Division or industry, but the Division also, that if we were to, in essence, tell you in that cause and nature of venting and flaring, in essence, which category it is going to fall in, that would be a cohesive, if you will, connection to where you are going to find these very volumes, reported, once they finally get reported on whatever monthly form there is.

So it seems to me, it seems to us, I should say, that this actually structures this in a way that is helpful to the Division.

Q. I mean, this is a silly question, but is it too structured? Sometimes too much structure isn't always a good thing.

A. I understand that. And we thought it was a good -- a good structure. We thought, well, if we are going to have to structure the stuff and it is going to have to be recorded in our own systems, we would like to set up a structure that says, "Hey, when the field guy says this happened, when you send

that into the office, well, what bucket do I put that in? Why don't we just build a bucket saying the starter."

Q. All right. Let's go to 19.15.25.9(A)3 and 4.

A. Can you give me a page reference?

Q. It is not in the NMOGA one, it was an add by the division, I think, after that. It is at Page 7 of the Division 27 redline.

A. Got it, yes.

Q. It has to do with the acquiring wells. You have some concerns, I think, on this. I don't know what day it was, Thursday or Friday, about maybe the need for flexibility if an operator acquires wells, et cetera. Was that correct?

A. We do have, I guess, some concerns about it, but we believe that this language that the Division has put forth addresses those needs.

Q. Okay. All right. So actually that is a good clarification. So NMOGA is good with 3 and 4, those proposals?

A. We are. And, of course, the 3 deals with acquisitions, as you just mentioned. We are good with that. We think that that is a proper way to handle it from the upstream side.

And the second one is a little more -- it is not dealing with acquisition, it is dealing with companies that have come out of compliance, which you filed, and we are good with this, too. It provides a process for the industry to, in essence, converse with the Division as to what has happened and perhaps what they need to get back into compliance. And yet, it also gives the Division the authority, explicit authority, very, very clear authority that they have got some very serious tools in their administrative, and, I guess, penalty toolbox to make sure that this rule is going to be adhered to. So, yes, we have reviewed this and we are good with that language as well.

Q. Okay. Thank you for your clarification. I did not put a citation on here for this comment. It has to do with alarm, I believe.

A. Yes.

Q. I believe that NMOGA's proposal was that it should be once a year to incentivize, not twice.

A. That is correct.

Q. Is that correct?

A. Yes, ma'am.

Q. I mean, couldn't that put actual operators in a situation, or let's play theoretical here. You

do your alarm monitoring, whatever that may be, it is a one-time thing, some operators. It could be a technology that is static on site, I have no idea. But let's pretend it is something like a flyover, and you do your flyover on Day 1, well, then on Day 3 you spring a leak somewhere. Are we now in a situation where instead of sitting there maybe going unnoticed for half the year it is going unnoticed for an entire year potentially? Does it not put it in sort of that situation where these could actually be sitting there for longer?

A. I guess that is theoretically correct. But, again, this is an add-on. This is an addition to all the other measures that this rule has in place, the NMED has rules in place, and operators themselves by their own volition have in place to look for leaks.

Do we expect to be able to find some additional leaks with this alarm technology, well, perhaps, and especially as technology develops over time. And from a theoretical standpoint, I see your point, but from a practical standpoint we thought it would be better to incentive the operator to use this technology by not requiring them to use it twice a year, but just once a year.

Q. Didn't NMOGA do any sort of tolling of operators to justify that, like, what other operators would be more incentivized, what percentage of operators would be more incentivized to use this technology if it was once not twice?

A. Well, we didn't catch your statistics on that, but we definitely got a sense that they're -- in essence, there were operators who -- well, that they would be willing to do it once but not twice. I can't give you statistics. We didn't do an actual poll, if you will.

Q. Okay. So in the OCD proposal it is not in NMOGA proposal, it was, I think, an add after. 27.9D1D. It is on Page 9.

A. Yes, I have got it.

Q. It is a description of operational best practices that were used to utilize venting during active and planned maintenance in the natural gas plan.

A. I see that.

Q. I don't remember your exact testimony, but I wrote down, again, you referred to prudent operators and that this was unnecessary because prudent operators are already doing something of the such.

So my question would be do you think all operators are prudent?

A. No. In fact, I think you probably wouldn't have a definition for prudent operator if there were some that weren't. So kind of by the fact that you've defined it, there may not be -- there may be some operators that I wouldn't consider prudent operator.

Q. Okay. Well, does the Division, or do you agree that the Division has to write rules that regulate all 461 operators in the State and not just prudent ones?

A. That is a correct statement.

Q. So could that be a good addition for the operators who maybe aren't as prudent?

A. I guess my perception of this is that if an operator is going to be an imprudent operator, it won't make any difference that he is sent a piece of paper in describing best practices.

So our, I guess our recommendation to not except this particular subsection is more of it doesn't seem to us that it is going to result in any better operations and prudent operators are probably going to be imprudent -- and imprudent operators are going to be imprudent, regardless of whether they

are sent you a piece of paper or not. That's really kind of the basis for our position.

Q. Do you think that there could be an off chance that maybe it would push some operators to do planning that they may have done before and could potentially have a positive impact?

A. Well, I certainly can't disagree with that theoretical.

Q. Okay. All right. Do you have the Climate Advocate information?

A. Yes, ma'am.

Q. Okay. I think it is 27.9.D2C. No, D. Their proposed D. 27.9.D2D. I think it is on Page 10, maybe, of their proposal.

A. That is what I have.

Q. Okay. It says the name and location. Basically it is in the Natural Gas Management Plan, the name and location of natural gas processing plant receiving or anticipated to receive natural gas from the gathering system.

I think you testified that, you know, again, I think you have talked about it clearly today. There could be multiple routes, right, that gas can go. You know, the gathering system is more of a spiderweb than a series. So that itself may be

impracticable.

Would something more like listing the company or potential gathering companies where it could go be more feasible instead of listing, it is going Gas Plant X. It is going to Company A who owns Gas Plant X and they are the only ones we have contracted with, or we have contracted with Company A, B and C and, you know, instead of going to the detail of plant, of like what processing plant it is going to, does the level of detail, like is going to company, this company, or I have contracted with two or three companies. But that, and not say for certainty it is absolutely going here, we just know that one of these companies is going to pick it up and take it, not literally pick it up, pipe it out.

A. I think, I understand your question. Some of the realities of this are that we certainly plan quite, usually, quite a time away and quite an advance of when you are actually going to spike a well. It can be a year, it can be two years. So you don't necessarily know what company you are going to connect, you are going to contract with.

You certainly know what companies you may have reached out to, but you may not know which company that you're going to actually connect with.

You may have had enough conversations with several of the gas gatherers in the area and especially if you have got the flexibility to contract with multiple, with one of several that you may have communicated with.

And so do we have the ability to tell you who we are going contract with. And, of course, you could say, well, anticipated to connect with as long as that is not, you know, hard where we say we are going to contract with Company A and later contract with Company B. That is some kind of a ding on our reputation or something like that.

I guess I am struggling a little bit here with the theoretical, knowing the practicalities of how APBs and the timing of how things go, we are in the climate advocates. We are in Section 2.

Q. Yeah.

A. Section D2, so if I looked in D2.

Q. Are you going to NMOGA's proposal?

A. I am. I just want to be sure that I don't misquote something.

In our -- in D2, I think it is even in your -- in the Division's. Well, here who actually says that in D2B, this is the operator that is submitting to APB would have to give you the

information on the existing natural gas gathering system the operator has contracted or anticipates contracting was to gather the gas. We have not struck that.

Q. That would be B3?

A. DB -- yes, D2B which says, "The existing natural gas gathering system the operator has contracted or anticipates contracting with to gather the natural gas, including the name of the natural gas gathering system operator."

So it seems to conform to what you were requesting.

Q. Okay. Yeah, I see that, so it may be already covered potentially. Okay. That was helpful.

MR. FELDEWERT: You just saved me a redirect question. Thank you.

Q (By Chairwoman Sandoval) So you testified, again, I think this has come up earlier. But you talked about the concern about that NMED is the air quality regulator, right, and they are the ones who can dictate air quality, so whether or not you vent or flare.

Are you familiar with the regulation that this Part 27 and 28 is replacing from OCD's rules?

It is 19.15.18.12.

A. No, I have not focused on this one.

Q. I am going read you 19.15.18.12, at least part of it. "The operator shall burn all gas produced and not used and report the estimated volume on a C-115."

I think, I guess the question here is do you believe that burning likely meant flaring?

A. Well, I am not familiar with that rule and its context. I think I better just say that I don't know because the context is important. I am just not familiar with that particular part of that rule or any part of that rule, quite frankly.

Q. I think it came from us in OCD's presentation. Now I have to pull it up.

Order R4070 and then followed after that R4382, which were written in, I believe, in 1970 and 1972. So they are old.

A. Like me.

Q. With that context, do you think at that time in 1970 burning could have meant flaring?

A. Again, I really hate to speculate because I have not read the rule and context is important.

Q. Well, how else do you burn gas?

A. Well, again, I am not trying to be

argumentative, I just know that context is important and I have not read that part of the rule. I just think it would be inappropriate for me to try to respond to that.

Q. Okay. You talked about on Friday in the context, I think it was talking about royal and other royalty conversation. And you mentioned that companies have to send 1099s. Is that true?

A. I said that and I've done some research over the weekend and found that that is not always true.

Q. If it were true, would those be mailed?

A. Well, I don't know, but it isn't true, it isn't always true.

Q. If it is true, is it likely that that is mailed?

A. Well, again, the premise is if it is true and it is not true. There is a level below which a company has to file or to send that, 1099s. So it isn't true. I misspoke. I think I tried to correct myself at the time because I didn't know and I did some research over the weekend and found that it isn't true 100 percent of the time.

Q. Okay. Well, that is a good confirmation.

A. Okay.

Q. All right. Let's go to 28.9.

A. Page 9?

Q. No, Part 28, 28.9, the location requirements.

A. Yes.

Q. I believe NMOGA is at least modifying or planning to strike C?

A. Yes.

Q. And C is, "No later than May 31st of each year the operator shall file the Division an updated GIS digitally formatted as-built map of its gathering pipeline or natural gas system which included GIS layer that identify the date, location and volume of incident flare natural gas, of each emergency malfunction and release reported to the Division."

I think was it correct that your concern was that last part, the GIS flare that identifies the date, location, emergency malfunction, all that kind of stuff, was that the main concern where -- what was the issue?

A. The issue is it really kind of fits one of our overarching ideas, if you will, in trying to not be duplicative in reporting. And all of this information that is in that suggested layer, the

date, location, volume of vented flared natural gas, of each emergency malfunction release reported to the Division, that information has already been filed typically through C-129s. So it seemed duplicative to send that in again in their report. That is really the basis for our desire to strike that section. It is not diminishing the information that the Division has, it is just trying to avoid having to report it twice.

Q. So but, I believe Section F above in 8 says that, "The operator shall notify the Division of venting or flaring that exceeds 50 MCF in volume and intervals or emergency or malfunction or the last eight or more cumulatively within a 24-hour period from a single event."

That would not capture things under 50 MCF, correct?

A. That is correct. It is less than 50, a C-129 is not required.

Q. So then it is possible that the Division's files will not have all venting or flaring captured on a C-129 that could then somehow mesh with the GIS map; is that correct?

A. Actually I can see that.

Q. So then C wouldn't be duplicative because

C would not include all information, correct, or because the Division would not have all the information already?

A. I see your point. I think our perception of that it is going to be mostly duplicative.

Q. But not fully, correct?

A. I can see your point.

Q. Okay. Are you familiar, by chance, with 19.15.18.19? It is titled Gathering Transportation -- Gathering, Transporting and Sale of Drip.

A. Likely not in any real detail.

Q. Okay. I can read to you Part G of 19.15.18.19, and I would like to hear if that may end up being duplicative, assuming this rule goes into effect as proposed by the Division for all major modifications.

It says, "A gas transporter shall, on or before the first day of November of each year, file with the Division maps of its entire gathering and transportation systems, locating and identifying on the map each drip trap in the systems, the maps to be accompanied by a report, on Division-prescribed form, showing the disposition being made of the drip from each of the drip traps."

I guess maybe what I am wondering is would it be more appropriate to combine or to sort of combine those requirements, or would it be more appropriate to leave them separate since this is, I guess, a natural gas waste and drip is a waste. Drip is not a gas waste, I'm sorry.

A. I am not familiar with that rule and so without having thought about it and discussed it with the team, I think I would just be speculating. I really hate to do that, so I better pass.

Q. Okay. Does it sound from that rule to you that all natural gas gathering systems should already be reported to the Division?

A. Again, I better not speculate. I am not -- again, the same as we talked about earlier, context is important, so I would prefer not to -- I am not familiar with them, I probably shouldn't say anything about them.

Q. Okay. Well, I think --

MR. FELDEWERT: Madam Chair, this is Michael Feldewert. We do have another witness that will address that particular issue.

CHAIRWOMAN SANDOVAL: Which one is that?

MR. FELDEWERT: Mr. Rankin.

CHAIRWOMAN SANDOVAL: Okay. I think that

is my last question.

THE WITNESS: Thank you, Madam Chair.

CHAIRWOMAN SANDOVAL: I think that is it. Thank you, Mr. Smitherman.

THE WITNESS: Thank you.

HEARING OFFICER ORTH: Thank you, Madam Chair. Mr. Smitherman, we would turn now to redirect.

Mr. Feldewert, we have been going more than an hour, would you like a short break before redirect?

MR. FELDEWERT: I think that would be very helpful and I just want to clarify, I don't know if any of the other Commissioners have questions before we do that.

HEARING OFFICER ORTH: Okay. I can ask if they have questions after their questions on Friday.

Commissioner Kessler, do you have additional questions?

COMMISSIONER KESSLER: None in addition to the ones that I asked on Friday. Thank you.

HEARING OFFICER ORTH:

Commissioner Engler, did other questions occur to you?

Can't hear you, Commissioner Engler.

COMMISSIONER ENGLER: Yeah, something real quick from the previous discussion.

EXAMINATION

BY COMMISSIONER ENGLER:

Q. Mr. Smitherman, let's go back, it is in the -- it is in the NMOGA. It is that Part 27B. It takes you to Page 7 and it comes back to the director was asking about venting and flaring during drilling operations.

A. Yes, sir.

Q. And the discussion between the Division's technically feasible and your reasonably practicable. It seems -- let me ask it this way: Under the Division's request of technically feasible it appears to me that the concern is the word, is the modifier "technically"; is that correct?

A. I think the whole term "technically feasible" and, you know, because think about it in terms -- another place where that is used. In the quality language and in our -- NMOGA's proposed language on when separations go back, in fact, again, technically feasible for a separator to function has some, I guess, some bounds to it.

And we were concerned that "technically feasible" in this particular arena might not have

those same bounds to them. So asking for "reasonably practical" seems to us to be a more clear and desirable modifier, if you will.

Q. Well, I think in these questions and discussions, I think you are finding that I think we have concerns about the modifier "reasonably" and so -- and I think -- let me see how I can pose this.

I think our problem here that we are going to have to solve is the modifier such that it is feasible and/or practicable, and I think the problem is that we are the modifier, what side of the fence you want to go on, is creating this discussion. I would say -- well, really quickly, though, when you say "practicable," you know, you are saying practicable using best industry practices. You're kind of duplicating your practicable because you are already saying best industry practices, are you not?

A. We are but, of course, practices is different than practicable. Practices is things that people do and practicable has a connotation of, if you will, practicality. I think you can't use the same root word, don't we, here. But they are really different, and, you know, feasible, reasonable and/or practical, that would maybe be helpful. We thought long and hard about what words

to try to put here that would convey, convey as clearly as we could that companies should be held to a reasonableness test and the "technically feasible" goes beyond that, perhaps, in some people's interpretation. So we struggled, really struggled with trying to find the right word that conveyed a reasonableness, not necessarily an economic test but it's a reasonableness test. And that is why we came up with "reasonably practical."

COMMISSIONER ENGLER: Thank goodness we are not English majors.

Thank you very much. Thank you, Madam Chair.

THE WITNESS: Thank you, sir.

HEARING OFFICER ORTH: All right. Thank you, Commissioner Engler.

Let's take 15 minutes. It is 9:48, that would put us back at 10:03.

(A recess was taken from 9:48 a.m. to 10:04 a.m.)

MS. FOX: I would like to ask the Hearing Officer.

HEARING OFFICER ORTH: Ms. Fox.

MS. FOX: Thank you, Madam Hearing Officer.

I am going to ask for leave to ask just a little bit of follow-up of this witness on one particular limited area that I believe needs clarification. I would also note that our cross so far in this proceeding has been very limited. I know I am asking to go a little bit out of order for leave, but I would like some clarification on a particular point.

HEARING OFFICER ORTH: All right. Mr. Feldewert, I would suggest to you that it would be better to have Ms. Fox ask her questions prior to your redirect of Mr. Smitherman.

MR. FELDEWERT: Ms. Fox, are you going to be asking them or is Mr. Baake who was the initial inquisitor?

MS. FOX: I am because, you know, in a normal situation we would be in the same room and over the break we could have conferred. It is just very difficult to do that right now, so I am also asking leave that I be able to conduct this examination. It is very short. We are already probably taking as much time as my questions.

MR. FELDEWERT: I have no problem as long as we have additional leave as necessary.

HEARING OFFICER ORTH: All right. Thank

you, Mr. Feldewert.

Let's see, Mr. Smitherman, do we have you back on the screen, please.

THE WITNESS: I am.

HEARING OFFICER ORTH: All right. Please, go ahead, Ms. Fox.

EXAMINATION

BY MS. FOX:

Q. Hello, Mr. Smitherman. Thank you for your testimony.

A. Thank you, ma'am.

Q. I am going to refer you to NMOGA's proposal with regard to -- it is under venting and flaring during drilling operations, AP1.

A. I am there.

Q. And that provision reads that, "The operator shall capture combust natural gas, if technically feasible, using best industry practices and controlling technologies."

That is OCD's proposed language, correct?

A. I see that.

Q. And NMOGA's proposed language is to delete the words "technically feasible" and insert "reasonably practical," so that that provision reads, "The operator shall capture or combust

natural gas, if reasonably practicable, using best industry practices and controlled technologies"; correct?

A. Mostly. You used the word practicable and our language is "reasonably practical."

Q. Thank you.

Now you have testified this morning and last week, I believe, that NMOGA did not like the term "technically feasible" because while some operations may be technically feasible they may be very expensive and you analogized that to going to the moon, which is technically feasible, but very expensive. Wasn't that your testimony this morning and last week?

A. Yes, ma'am.

Q. But then under questioning by the Chair and Commissioner Engler, you said in response -- do you remember the Chair's line of questioning, it was around whether expense was a reasonable thing to expect for additional prevention of waste? She was asking is it reasonable to expect that operators may have to spend a little bit more in order to manage their waste and you said, "Yes."

A. I don't think that exactly characterizes my testimony. I recall the exchange.

Q. What was your testimony?

A. I think she asked, and we could go back to the record if we need to. I think she asked if I recognized that sometimes it will cost operators something to dispose of waste, and I said yes.

Q. And then she was questioning you about the language that you're proposing, "reasonably practicable," and whether the insertion of that language may cause, as she put it, mischief because operators would interpret that to mean that they don't have to spend a lot more money on -- to prevent or manage their waste; is that correct?

Do you remember her questioning?

A. I remember the exchange, I don't know that I remember that exact language, but you have oriented me to kind of generally where we were. So do you have a question about that?

Q. Yes.

So she was asking you about that. I wrote down that you testified that cost is not a factor in the consideration of reasonable practicality and then Dr. Engler asked you a series of questions about this provision as well just before our break, and you told him that if -- that economics wasn't a factor in the assessment about whether something is

reasonably practical.

So I am wondering whether cost is or is not a factor in the assessment about whether an operation is reasonably practicable because I believe you testified that it is and it is not.

MR. FELDEWERT: Hold on. Let me object, Ms. Fox, a couple of things. One, I suggest maybe you cut down your question with all the additional language and remember, again, what reasonably practical, which is different from practicable. So I would ask that you -- I object to the form of the question and just ask now that we have oriented it, pinpoint your question and get his answer.

MS. FOX: I will be glad to rephrase, but I think after being corrected by Mr. Smitherman, I am using the term reasonably practical.

Q. (By Ms. Fox) Mr. Smitherman, can you just answer us very directly whether cost is or is not a factor in considering whether equipment is reasonably practical under NMOGA's proposal.

A. I think it's one factor. I think when we look at the impact, potential impact, to drilling operations and it is -- in one sense it is a larger concept than just cost. Cost will certainly -- can be a factor but there is applicability of particular

practices on a particular drilling rig that may not be practical. It just, I should say technically feasible.

So I guess the short answer is, as I am thinking through this, it may be one of the factors.

MS. FOX: Thank you. That is all.

HEARING OFFICER ORTH: Thank you, Ms. Fox.

Mr. Feldewert, I believe it is time for your redirect.

MR. FELDEWERT: Thank you.

FURTHER EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Smitherman --

MR. FELDEWERT: First off can I have an opportunity to present, so I can share my screen.

Q. (By Mr. Feldewert) Mr. Smitherman, can you see my screen? I should be on Page 10 of the Division's proposed modification under OCD Exhibit 2A.

A. I do see that, sir.

Q. Mr. Baake, Ms. Fox's colleague, had some good questions to you about this Subsection 27.9D6B, which should be on the screen in front of you.

A. I see it, and I got it in my hand, too.

Q. Okay. And in particular he was asking

about this 90-day period?

A. Yes, sir, I remember that.

Q. I want to make sure it's clear how this works, Mr. Smitherman. Once an operator determines that they are -- that it is out of compliance, am I correct that under this provision they are required to submit a more robust natural gas management plan?

A. That is correct.

Q. And that as part of that they are required under this provision to examine, and I am looking at the language the Division has inserted, "Each well it plans to spud during the next 90 days."

A. I see that.

Q. Okay. What happens, Mr. Smitherman, if an operator remains out of compliance the next month?

A. Well, the language, and our expectation, it would cause that operator to have to, in essence, roll this same language forward one more month.

So it is a rolling requirement that each month is cumulative month that you are out of compliance. You have added another month to your requirement to submit the more detailed gas management plan on every well that you expect the spud in that next period of time. So it is always 90 days out from where you are out of compliance.

Q. Okay. Mr. Smitherman, in your opinion do you think this will provide an additional incentive for operators to get back into compliance?

A. Certainly.

Q. Now, I want to ask you about a question from Commissioner Kessler involving 28.8G1C. And her question, Mr. Smitherman, related to NMOGA's concerns it is about the certifications required in this rule.

Do you recall that questioning?

A. I do recall that.

Q. Okay. Mr. Smitherman, first off, there are various points in the rule where operators are required to certify certain information; is that correct?

A. That is correct.

Q. Now, am I correct that the only place that the division of NMOGA has concerns about the certification is in this particular subsection which exists in both Part 27 and in Part 28?

A. That is correct.

Q. And is NMOGA's concern related to the fact that at this point we would not know what additional information would be requested?

A. That is correct.

Q. And, for example, I think you mentioned that could include third-party payor?

A. True. The concept there is we don't know what the Division is going to ask for. We don't know what the source is going to be. So if we are reluctant to state before the fact that we will be able to certify that data. It is a fairly small, I guess, subset of all the things that would be reported to the Division, but we are simply unable to know whether we can certify that or not ahead of time.

Q. And so to answer Commissioner Kessler's question more directly, do operators have any concern about certifying, for example, estimated volumes?

A. No. As long as we -- I guess, the short answer is no, that is not a problem.

Q. All right. Now, Commissioner Sandoval had some questions to you, Mr. Smitherman, about low pressure sources, low volume sources. Okay?

A. That is correct.

Q. And staying here within G2, she was questioning you about NMOGA's suggestion to delete from the monthly reporting the categories such as manual liquids unloading, uncontrolled storage

tanks, et cetera, that are reflected in NMOGA's changes to Subpart G2?

A. That is correct, I recall.

Q. Okay. And there was a question about whether just reporting that is currently being suggested would or would not be counted against operators under the gas capture obligations?

A. That's correct.

Q. So I want to talk briefly about that.

Is it true, Mr. Smitherman, or I will ask you this: Based on how we read the rule, does it appear that any category that is listed here in G2 represents categories that would be counted against the operators as part of their gas capture with certain exceptions?

A. That's correct. Unless they are explicitly exempted, they would be counted against us. That is our reading of the Division's rule.

Q. Okay. That would include, for example, this other column that we see down here at the bottom of the list down under Subparagraph M, as in Mary?

MR. AMES: Objection, leading questions. This is redirect, not cross.

HEARING OFFICER ORTH: Mr. Feldewert, if

you would watch that, please.

MR. FELDEWERT: Sure.

Q (By Mr. Feldewert) I think you said all categories, Mr. Smitherman?

A. Yes, I did.

Q. Would it include this Subpart M, other?

A. What page are you on, sir?

Q. I am on Division's proposed.

A. The Division's proposed.

Yes. Now I am on the right letter. So other would count against us, as we see it.

Q. All right. As a result NMOGA has proposed the deletion of certain categories in this section, correct, Mr. Smitherman?

A. That's correct.

MR. AMES: Objection, clearly a leading question.

HEARING OFFICER ORTH: Mr. Feldewert, again, if you would watch that, please.

Q (By Mr. Feldewert) Mr. Smitherman, would you -- how would you characterize the categories that NMOGA seeks to exclude?

A. Well, we would like to exclude those categories that are difficult if not impossible to measure with any accuracy sufficient or appropriate

for production accounting reasons. And that would have an effect of those volumes not being counted against us on a gas capture requirement calculation.

Q. Okay. Just to be clear now having oriented ourself to G2 and all of these various subparagraphs, I want to go to the actual accounting. Okay, Mr. Smitherman?

A. Certainly.

Q. Let's go to 27.9B Paragraphs 1, 2, and 3.

A. I am with you.

Q. Okay. Now, as I read Subparagraphs B1, these are B1, 2, and 3. As you read it, Mr. Smitherman, are the only categories from Subpart B that would be excluded from the accounting?

MR. AMES: Objection, leading.

A. That is exactly it.

MR. AMES: Mr. Feldewert, you are not testifying, the witness is, so you need to ask questions that ask him for his testimony not tell him what his testimony is.

MR. FELDEWERT: I am trying to be efficient here, Mr. Ames, so we can get through this.

HEARING OFFICER ORTH: All right.

MR. AMES: Madam Hearing Officer, I have no objection to using leading questions to set up a topic. I do have an objection to leading questions which ask for the witness' opinions on certain things.

HEARING OFFICER ORTH: All right. Again, Mr. Feldewert, please proceed using a question and answer format.

Q (By Mr. Feldewert) Mr. Smitherman, how do you read the subcategories under 27.9B1, 2, and 3? How did it relate to the accounting?

A. The subcategories that you referred to lay out or line out those categories that would be excluded from the gas capture calculation that is referenced earlier in this rule.

Q. And based on your understanding of the rule, if they are not excluded, does that mean they are included?

A. Yes, sir. If they are not excluded they are part of what has to be reported or, excuse me, what counts against the operator in their gas capture.

Q. All right. So let's walk through these various subparagraphs. Okay?

A. Certainly.

Q. Just so we are all clear.

When you look at subparagraph B1 and its reference to Subparagraph A, Subpart 2 of G2, what is referenced in Subparagraph A?

I could tell you but I don't want to cause a problem?

A. I understand that and I don't want you to cause a problem. So Subsection G2, Point A.

Okay. I am with you. Subparagraph 1 refers to, in essence, the exclusion from counting against the operator for natural gas capture calculations Item A2A emergencies.

Q. Okay. Subparagraph B2 that says, "Beneficial Use"?

A. That's correct. It says, "The volume of natural gas reported is beneficial use," is also excluded.

Q. Okay. Subparagraph B3 we see a reference to H?

A. I see that.

Q. What does that refer to?

A. H little I, is the volume of gas is not suitable for transportation because it has nitrogen, hydrogen sulfide and carbon dioxide in it.

So those volumes are, if flared, are

excluded from counting against an operator on a gas capture percentage. The little I, is -- it is a little confusing, but it is actually the next subparagraph, the same level of H, which refers to normal operation of pneumatic controllers and pumps. So those aren't counted against the operator.

And then if you go to L of that same list, that is flaring from a delineation well. So those limited categories are very explicitly excluded from counting against an operator, which in our reading of this rule, means that every other category or item would count against an operator.

Q. Everything that we see up here on the screen in G2?

A. That is correct.

Q. Okay.

MR. FELDEWERT: That is all the questions that I have.

Thank you.

HEARING OFFICER ORTH: All right. Thank you, Mr. Feldewert. Thank you, Mr. Smitherman. Is there any reason not to excuse Mr. Smitherman?

MR. FELDEWERT: No, Madam Examiner. We would then be in a position to call our next witness who will be presented by my colleague, Adam Rankin.

HEARING OFFICER ORTH: Thank you. Mr. Smitherman, you are excused.

THE WITNESS: Thank you, Madam Hearing Examiner.

(Witness excused from the proceedings.)

HEARING OFFICER ORTH: I did just want to put a few things on the record, Mr. Feldewert, before you called your next witness.

One, we were in a conversation, which preceded the beginning of the transcript this morning. And, again, I just want to put a few things on the record.

One, although there was an opportunity for folks to sign up for public comment at the 8:30 session this morning, no one had signed up for it. So we did not break into the technical presentation to take any public comments. At this moment I am unaware of any public comment at 4:30, that might change, we will see.

Number 2 was Ms. Paranhos noted that the witness she mentioned last week who had a conflict and needed to go out of order no longer has that conflict.

Number 3, Mr. Feldewert, would you please on the transcript say what the relationship is

between NMOGA and IPANM for the purposes of this proceeding? I believe Commissioner Kessler was in a conversation with you about it. As I understand it, you have not entered an appearance on behalf of IPANM, but IPANM somehow supports NMOGA's proposal. I wasn't sure I was clear on that.

MR. FELDEWERT: The modifications were filed by New Mexico Oil and Gas Association.

Mr. Smitherman indicated during his testimony that it was his understanding that IPA New Mexico, likewise, agreed with and assisted in coming up with the modifications that were filed by the New Mexico Oil and Gas Association.

HEARING OFFICER ORTH: Thank you for that. That is my memory of the things we needed to get on to the transcript. Is there any reason not to proceed to -- oh, one more thing.

The Commission has asked that counsel review the prehearing statements and in particular their estimates of time for each of their witnesses who have not yet spoken and include the -- under maintain the estimate already filed in the prehearing statement or revise that estimate. And if you would do that, please, with an eye to whether you intend to offer some rebuttal as part of your

direct so that we could perhaps reduce the amount of rebuttal expected after the entirety of the round of direct presentation.

I believe that was it. Is there anything else we needed to talk about on the record before we proceed to another witness?

All right. Mr. Feldewert, if you would, please. I'm sorry, Mr. Rankin, if you would, please, introduce yourself for the record.

MR. RANKIN: Good morning, Madam Examiner. Can you hear me okay?

HEARING OFFICER ORTH: Yes, I can. Thank you.

MR. RANKIN: I believe that Mr. Thompson is on, so I would ask the host that Mr. Thompson be made available as a panelist.

HEARING OFFICER ORTH: I see Mr. Thompson as a panelist. Mr. Thompson, would you speak up, please, so we know your sound is good.

THE WITNESS: Can you hear me all right?

HEARING OFFICER ORTH: Yes. If you could, please, raise your hand, please.

(Whereupon the witness was sworn.)

HEARING OFFICER ORTH: Okay. Thank you very much. Mr. Rankin.

BY MR. RANKIN:

Q. Good morning, Mr. Thompson. Could you please state your full name for the record?

A. My name is Paul Curtis Thompson.

Q. And by whom are you employed, and in what capacity?

A. I am currently the president of Epic Energy. Last year I sold my interest in Walsh Engineering to my partners, but I still do some consulting engineering.

Q. Where do you reside?

A. I am happy and healthy and proud to reside in Farmington, New Mexico, which has over 200 wells inside the city limits.

MR. RANKIN: Madam Examiner, in order to make this a little more efficient, if it is okay, just identify some of the exhibits and documents I am going to be referring to just so the Commissioners and others who are following along with us.

HEARING OFFICER ORTH: Thank you.

MR. RANKIN: So for purposes of Mr. Thompson's testimony, I am going to be referring to OCD Exhibit 2A.

Also OCD's Exhibit 4B, I believe is the

correct exhibit, which is the updated version of some other issues that we will be addressing in his testimony.

And, Mr. Ames, I do not have a marked copy of that exhibit, so I will probably be using the correct exhibit. If at the time I am not using the correct exhibit, just let me know.

In addition I will be referring to NMOGA's Exhibit A, which is the white notebook addressing the modifications in Part 27. And for purposes of testimony to make this easy, I will be putting up the modifications for each section that I will be addressing on the screen so people can follow along.

And finally, Mr. Thompson has prepared exhibits behind Tab D, which are in NMOGA's big binder Exhibit M through -- sorry, C through M. So behind Exhibit D are exhibits related to Mr. Thompson's testimony. I will not be sharing those on the screen just for ease and efficiency, but I will ask you to refer to those in the paper binders so that you can follow along.

HEARING OFFICER ORTH: All right. Thank you, Mr. Rankin, for going through those exhibits. I did hear a fair amount of ambient noise. I wasn't sure because I believe you and Mr. Thompson were the

only two unmuted, who it would be coming from. I would just ask perhaps that you watch the ambient noisemaking and perhaps mute yourself if it becomes clear in this proceeding for a while.

And, two, can we get an assurance that Mr. Thompson and the subsequent NMOGA witnesses will not be repeated in a duplicative way what Mr. Smitherman covered?

Mr. Rankin, for some reason you went soft there.

MR. RANKIN: Can you hear me okay now?

HEARING OFFICER ORTH: Now I can.

MR. RANKIN: Madam Chair, there has been in OCD's presentation, we presented an overview and we intend to give an overview of procedures proposed. We now have subject matter experts who will testify on particular changes and justifications for those changes. We are trying not to duplicate and we will skim over portions that Mr. Smitherman has addressed, but we would intend to go over in more detail on the bases and justifications for the particular modifications.

In Mr. Thompson's case, we will be talking about the AVO modifications for the audio, visual and olfactory inspections.

May I proceed?

HEARING OFFICER ORTH: I have a note from the technical host that the ambient noise was coming from Mr. Thompson. Mr. Thompson, I would ask that you mute yourself if you are not speaking and try not to pace around in your environment while you are speaking. That's all.

Thank you very much.

Mr. Rankin.

MR. RANKIN: Thank you very much, Madam Examiner. I will proceed.

Q. (By Mr. Rankin) Mr. Thompson, you will be -- your testimony will address NMOGA's proposed modifications to the Division's replacement rules as it pertains to auditory, visual and olfactory inspections; is that correct?

A. Yes. Especially the required documentation.

Q. Could you please briefly just review your work experience as it pertains to managing and overseeing production engineering and operations in the field?

A. Just briefly, yes I am a product of Farmington High School, New Mexico State University. I have a degree in chemical engineering but I am a

registered professional engineer in petroleum engineering in the State of New Mexico.

I was hired by Northwest Pipeline in 1980 as the drilling engineer and drilled multiple wells throughout the San Juan Basin for them.

I was promoted to manager of fraction drilling when the Williams companies bought Northwest pipeline.

I had that position until I left in 1992 to assume my father-in-law's consulting business. We take care of everything from permitting wells through plugging wells in the San Juan Basin. I have been able to grow that company from three people when I took it over to, we have approximately 50 employees now and operate over a thousand wells.

Q. And, Mr. Thompson, do you have experience overseeing the management, scheduling, ordination of field inspections and maintenance for production facilities and operations?

A. Yes, I do.

Q. Are you familiar with the term a prudent operator and its meaning?

A. Yes, I do.

Q. And are you also familiar with what would be considered prudent operating practices in the

field regarding the management and inspection of wells related to production facilities?

A. Yes.

Q. Now, you are familiar with what has been referred to as auditory, visual, olfactory or AVO inspections?

A. Yes, I am.

Q. And you are familiar with that, those types of inspections in the oil and gas industry and particularly at wells and related production facilities?

A. Yes.

Q. And finally are you familiar with the modifications that NMOGA has proposed to the Division's proposed rule regarding the frequency and the documentation of those inspections in Part 27?

A. Yes.

Q. And, Mr. Thompson, does NMOGA Exhibit D contain exhibits that you prepared to explain proposed modifications and justification for them?

A. Yes, I do.

Q. So we have already discussed this to some extent, Mr. Thompson, but just very briefly can you explain what are AVO inspections and what is expected within the oil and gas industry during

their performance?

A. An AVO inspection is something that you would expect your lease operator to perform every time they are on location.

I think it was my production superintendent that called it preferred 101. Before you start working on optimizing your production and checking your pressures and production numbers, you just are aware of what is happening on location. You look for leaks, you listen for leaks, you smell for any unusual odors, and you do that before you proceed on with your production optimization.

It is basically the same thing that you do every day when you leave your house where you look around and you say are the lights off, do I hear the toilet running, do I smell gas. You know, you do that kind of subconsciously, but it is a function that they do every single trip.

Q. Mr. Thompson, what is expected of a -- if during the course of one of these inspections an issue is identified?

A. Well, absolutely if they can be repaired immediately, it will be repaired immediately. Some things will require replacement parts, you know, which they will know right away and try to get those

repaired just as soon as possible.

Q. In your experience if an issue or a piece of equipment is identified during the AVO inspection and is fixed, is it common for an additional piece of equipment that was identified to be identified as an issue in an immediately subsequent AVO inspection?

A. Perhaps. You know, most of the equipment that you replace obviously is not going to be a problem, but not everything breaks all at once. There will be times where, say, a pressure regulator will stick or whatever and you tap it with your crescent wrench and it quits, you know, and it starts functioning again.

If you have to do that again the next day, then probably you are going to get a kit and replace the diaphragm and stuff in the pressure regulator.

But most of the time I think you are right that once you fix a leak, pipe or union, whatever it is, it is not going to happen again the next day.

Q. So you talked about the AVO inspections. Who is it that is conducting these AVO inspections at the time they are visiting these facilities?

A. Well, we call them lease operators. Some people call them pumpers or switchers.

Q. Who are they? Are they employees of the company, are they contractors? Generally who are these folks who are doing these inspections?

A. They could be, either. That is kind of what Walsh Engineering does is we contract pump wells for many different clients. It would be the -- sometimes they are a company employee, just depends on the structure of the company.

Q. Now, Mr. Thompson --

MR. RANKIN: If I might, Madam Hearing Officer, if I might be able to share my screen so I can put up OCC's Exhibit 2A?

HEARING OFFICER ORTH: Yes, I believe the technical host will allow that.

Q (By Mr. Rankin) Are you all able to see Exhibit 2, Page 4 of Exhibit 2A?

A. Yes.

Q. Mr. Thompson, if you would direct your attention to what is marked as Exhibit 2A in Paragraph 5, in particular. Do you see where under the proposed rule the OCD has laid out the types of facilities and components that would be included in the inspection?

A. Yes, I do.

Q. Are these the same facilities and

equipment that are included in an AVO inspection in an informal manner that you are discussing?

A. Yes.

Q. The same equipment that is listed here is the equipment that we saw an operator who will be inspecting as part of its normal AVO every time that it is on site?

A. Yes.

Q. Now, I mentioned to you that you are a prudent operator, do you consider it prudent operations to conduct an AVO inspection when a lease operator or pumper visits a well or facility?

A. Absolutely. That is the first thing we would expect from a lease operator to do every trip.

Q. Now, under this proposal, scrolling down through that rule, the Division -- is it your understanding the Division would require operators to conduct and document AVO inspections at certain frequencies depending on the average production rate and the category of well?

A. Yes.

Q. What are those proposed frequencies that the division is proposing?

Actually, Mr. Thompson, I am going to switch over to what OCD has marked as Exhibit 4B,

because I have made some slight modifications to the language.

MR. RANKIN: So I am going to reference that exhibit, Madam Hearing Officer.

Q. (By Mr. Rankin) Do you see the new language they are proposing under Paragraph 5?

A. Yes, I've got you now, sorry. All right. What they propose is on a well or a facility that what I call a non-stripper well is something that makes more than 10 barrels of oil a day or 60 MCF of gas a day, that those AVO inspections would be done weekly, and continue on for at least the weekly for the first year of any new well. Any stripper well or well that makes less than 60 MCF a day would have to be done monthly, if you're on location, or quarterly.

Q. Okay. Now, what frequency is NMOGA proposing for these formal documented AVO inspections?

A. Again, we are only talking about the documenting part. The AVO inspections are done frequently, but NMOGA and IPNM's recommendation is that non-stripper wells have a documented AVO inspection monthly and that the stripper wells have a documented AVO inspection quarterly, and that

shut-in ENA wells are annual.

Q. I am going to bring up NMOGA's proposed language around this, these modifications.

Do you see that language on the screen now where NMOGA's proposed modifications are in redline?

A. Yes.

Q. So I note that under Subparagraph C you have mentioned that NMOGA -- let me back up.

Under subparagraph, yeah, Subparagraph C, NMOGA was proposing a quarterly documented AVO inspection for what you termed low production wells or wells that are producing less than 60 MCF of gas per day.

Now do you plan just a little bit more outline in proposing this quarterly as opposed to -- as this was submitted in its modifications it is proposed monthly if it is on site, but quarterly in other instances?

A. Well, to tell you the truth, I wasn't really sure why the Commission would require documented AVO's more frequently if a prudent operator was on location more frequently than if they weren't. And so it made sense to me on these lower pressure, lower volume wells that the documented AVO inspections would just be required

quarterly, whether you were, you know, irregardless of how often you went to the location.

Q. So what NMOGA is proposing here is that because an operator is going to be on site on a regular basis conducting these informal AVO inspections, it makes more sense to just require them quarterly, modification quarterly reporting for those low producing wells?

A. In my opinion, yes.

Q. Does the volume of production have anything to do with our recommendation as well?

A. Yes. You know, I think the Commission correctly split out the difference between non-stripper wells and stripper wells just because of the administrative burden in doing the documentation.

Q. So now, let's get into exactly the issue with what the Division is proposing and the concerns about it.

If operators are conducting these AVO inspections informally every time they are on site at the facility, what is the problem with the Division's proposed formal AVO documentation frequency for each of these categories of wells?

A. Well, the documentation part is going to

require scheduling, you know, actually doing the documentation on site and then tracking those reports and storing those reports.

Q. So there is a difference between what operators are already doing informally and what the division is proposing to do on a formal basis, and that is really the administrative burden of documenting those inspections?

A. Yes.

Q. Now, do you -- can you explain how in your opinion formal documented AVO inspections, in your opinion will they tend to identify opportunities of resurface waste?

A. I don't see that. I mean, there might be some serendipity the day you're scheduled to do your documented AVO inspection you find something that you didn't find the day before when you were doing your informal documentation, but it seems highly unlikely.

Q. So to be clear, NMOGA is not opposed to documenting the AVO inspections, it is opposed to the frequency of the documentation; is that right?

A. That is correct.

Q. Okay. So let's -- if you would, Mr. Thompson, I am going to ask you to refer to -- I

will stop sharing my screen.

If you would refer to NMOGA's D1 -- I'm sorry, D3. If you would just review for the Commission what this slide shows is explaining how these documents of formal instruction develop in NMOGA's concerns.

A. After we read the preliminary rules we thought about how we would accomplish these tasks and we thought this is fairly similar to what we do for bradenhead tests where we would have to schedule the tests.

You know, in the bradenhead scenario we are given a list of areas at least in the Aztec district, and then we have to schedule the test with the lease operators, tell them when you need to have those tests completed.

You send out the forms to the lease operators, the lease operator then has to actually perform the test, do the documentation, return the form back to the office. Somebody at the office has to then collect all of those forms, make sure that all wells were covered, submit those to the OCD and then file them in a manner to which, if they were requested, we would have to produce those forms, again, five years down the road.

Q. So, this Exhibit D3 is based on your experience in having to prepare formal documentation inspections for bradenhead well inspections; is that right?

A. Yes.

Q. Okay. Now, so you use this to establish an instrument for what the impact would be on the Division's proposed AVO inspection frequencies in the current rule, in the proposed rule?

A. Yes, I am.

Q. Can you flip to the next page, D4, Mr. Thompson, just review how you use that experience or analogy with bradenhead well inspections to come up with an estimate of the impacts for AVO inspections in this case?

A. Okay. We start with a scheduling function, because the difference based on volume of the producing well, whether it is a weekly or a monthly or a quarterly, whatever the proposal that you have got to keep track of that production because we will have wells that will be in and out of that criteria all the time. So I assign that constantly.

Q. Mr. Thompson, go ahead.

A. Okay. So I had assigned those tasks to

just a production analyst. So they would -- they would figure out which wells needed to be tested at what schedule. They would then send that out to the production foreman or to the lease operators.

And then I would assume that the documentation part of the AVO would only take about 15 minutes on location for the operator to walk around.

HEARING OFFICER ORTH: Mr. Rankin and Mr. Thompson, go ahead.

A. Usually these technical difficulties only happen to me so I am glad to have company.

Anyway, after the 15 minutes that I estimate that it would take the lease operator to fill out a checklist documenting the AVO inspections, then you would have to transmit that somehow back to the office where, again, then the production clerk would have to collect all of these and make sure she has got them all, they are all signed and dated, whatever, and then scan those in to some sort of a system where we could find those, sometime in the next five years at the Commission's request.

I guess, if I could to make this more sense, I guess going back to my example as you're

leaving your house and you check for the lights and the water running, et cetera, et cetera, imagine that you are the building manager of a 450-unit complex and you have to do these AVO tests documented on different schedules based on the occupancy of each apartment.

So you would have to know whether one of your tenants has family members visiting or not, and whether they are over the limit or not. So you would have to then notify each one of your tenants weekly whether or not you needed to document an AVO or not. You would have to tell them what the checklist required and then you would have to collect all of those checklists at the end of the week or at the end of the month. And it would always be, you know, I sent out 450 of these and I only got 430 back, so which 20 didn't I get and then you have to knock on doors and collect all of that stuff. By the time you got finished with that, then you would have to start it the next week. It is more than just checking a box.

Q (By Mr. Rankin) Mr. Thompson, just for clarity your analogy with the building manager there, your building manager would be your production analyst in your chart who is charged with

tracking, reporting of each of the apartments in that scenario; is that correct?

A. Yes.

Q. Okay. So review, if you would, how your estimate turns out here in terms of applying this to the Division's proposed AVO documentation frequencies.

A. Well, based on the Commission's recommendations with the weekly checks for the non-stripper wells, I have tried to estimate manhours and so it looks like 962 total manhours for the non-stripper wells and 2756 total manhours which is equivalent to a 1.33 full-time equivalent.

Q. Then to be clear that is approximately how many wells are you talking about in Epic's case?

A. Epic currently has 34 non-stripper wells and 434 stripper wells. I was just using Epic as an example.

Q. So under the Division -- so to make sure I am correct, in the Division's proposed AVO documentation frequency, that would be an impact to Epic of an additional 1.3, the equivalent of 1.33 full-time job; is that correct?

A. That's correct.

Q. Or manhours.

Now, it would -- Mr. Thompson, just flip to the next page and review the same, your same analysis but with NMOGA's proposed AVO documentation frequency.

A. So all the base assumptions are the same as to how long it would take to do the scheduling, how long to do the documentation and how long to do the filing, it would just be a difference of the frequencies.

And so based on the NMOGA and IPNM recommendations, that would drop the administrative burden down to about .39 full-time equivalent.

Q. So not insignificant but not more than one full-time employee for Epic's case?

A. That's correct.

Q. Now, Mr. Thompson, just for clarification you, in your charts, have identified the term stripper well and we talked a little bit about that.

Does that -- these are low producing wells, right, they produce 60 MCF of gas per day average?

A. That is correct.

Q. Does that low production rate also mean they would carry less revenue?

A. Yes.

Q. And can you tell me a little bit about -- does that lower revenue also mean that those low producing wells are more sensitive to economics and regulatory ratings than non-stripper wells?

A. Absolutely. You know, the lower revenue you have to really watch the expenses in order to make anything left over at the end of the day.

Q. Now, I am going to ask you to turn to the next exhibit, Mr. Thompson, on Exhibit 6. If you would just -- if you could scale up what the Division's proposed AVO documented inspection frequencies are on a quarterly basis compared to the rates or rather the frequencies that NMOGA is proposing?

A. Well, using the NM OCD's well cam and we just ramped up the number of inspections that would be required for stripper and non-stripper wells, and under the OCD's proposal that would result in over 1.7 million documented AVOs a year in the State of New Mexico, whereas the NMOGA proposal would reduce that down to about 410,000.

Q. So just doing simple math that is approximately 1.3 million more AVO inspection records under the Division's proposal than under NMOGA's proposal; is that right?

A. That's correct. It seems like that would put an undue burden on the Commission even if they only reviewed a small portion of those.

Q. So do you have an opinion, Mr. Thompson, on whether the burden that is being -- would be imposed on the operators to conduct this documented -- these documented inspections would there be a -- would the benefit outweigh the burden here in terms of the imposition on operators, in your opinion?

A. No, I don't. You know, again, it would be kind of serendipity if you were to find something leaking during your documented AVO inspection that you didn't find before. However, I think it is important that we do document some of these AVO inspections just so the public is aware that we are really doing it.

Q. So, Mr. Thompson, one other thing I wanted to point out, in addition was that NMOGA had originally proposed lifting the documented AVO inspection for what are known as TA wells or temporarily abandoned wells. Is that still the case?

A. Yes. I think based on Brandon Powell's testimony, though, that there have been times where

T&A well was found leaking, which seems rather unusual to me based on the requirements that you have to go through to put a well in a TA status but probably limiting documented AVO inspection on a T&A well to an annual basis is not totally unreasonable.

Q. And that would put the T&A well under the same category as shut-in or inactive well under NMOGA's proposal which would be a once a year, or annual, documented AVO inspection?

A. Yes.

Q. Mr. Thompson, looking at NMOGA's proposed additions and modifications to the documented AVO inspections accomplished goal under the whole producing unnecessary excessive service waste without imposing unnecessary burdens on operators?

A. I do.

Q. Mr. Thompson, have you prepared exhibits -- I am just -- I didn't mention this, Mr. Thompson, but our Exhibits D1 and D2, are those correct copies of your CV and resume?

A. Yes.

Q. And did you prepare D1 through D8?

A. Actually D7 and D8 are just copies of the OCD rules concerning T&A wells but the rest, yes, I prepared.

MR. RANKIN: At this time, Madam Hearing Officer, I would move the admission of Exhibits D1 through D8.

HEARING OFFICER ORTH: Okay. Let me pause for a moment to see if there are any objections to the admission of Exhibits D1 through D8.

Hearing no objections, D1 through D8 are admitted.

(Exhibits admitted, D1 - D8.)

MR. RANKIN: Madam Hearing Officer, no further questions, and I pass the witness, at this time.

HEARING OFFICER ORTH: Okay. Thank you very much.

Mr. Ames, do you have questions of Mr. Thompson?

MR. AMES: Yes, I have quite a few questions for Mr. Thompson.

EXAMINATION

BY MR. AMES:

Q. Good morning, Mr. Thompson.

A. Good morning.

Q. So let's start at the top with the definitions. AVO is defined in Section 7 as audio, visual, olfactory, right?

A. Correct.
Q. Basically look, listen, and smell?
A. Yes.
Q. And OCD's draft rule lists the components that it would like operators to check during an AVO, and I believe you agree that is really all part of the pleading operators AVO anyway; is that right?
A. That is correct. That is not a total list but it is certainly everything a prudent operator should check, yes.
Q. Excellent. So NMOGA has no problem with that list?
A. No.
Q. And if a prudent operator finds a leak, I think you said you fix it right away if you can, correct?
A. Absolutely.
Q. And you keep track of those fixes, right?
A. Not necessarily.
Q. Not necessarily. Can you explain?
A. Well, I think if you are walking by a leaking hammer union and you just whacked it with your hammer to tighten it up and it quit leaking, I am not sure that the lease operator would mention that on his production report for the day. That is

just something that we expect to be done and so that is what I am saying. If he gets a crew out to replace a master valve or something because it is leaking, then certainly that would be something that would be documented.

Q. Okay. So, some leaks are more significant and if they require planning and coordinated personnel, they get documented; is that right?

A. Correct.

Q. And in our case those kinds of things would go on a production report that is kept for the day?

A. Usually the pumper would make some note of that, yes.

Q. So the pumpers keep notes when they are out there?

A. Yes.

Q. Now, there are no tenants at your well sites, right?

A. Tenants like people?

Q. Well, yeah people who live there like in a hotel or an apartment building as you used in your example?

A. No. We have several wells inside the city limits of Farmington, but nobody actually lives on

location.

Q. At least we hope not. So you would go to those sites whenever you want, right?

A. Yes.

Q. You don't need to check in with anyone, you don't need to knock on doors and cabins, right?

A. Correct.

Q. But in view of Mr. Smitherman testified that prudent operators do AVOs every time they are on site; is that right?

A. Yes.

Q. I think you said that it is something that needs to be done every time they are on site before checking the production number; is that right?

A. Yes.

Q. It is -- I think it is called subconscious. It is done on every trip. It is pumper 101; is that right?

A. Yes.

Q. Okay. So Mr. Smitherman testified yesterday and I will be asking, did you hear Mr. Smitherman's testimony?

A. Most of it.

Q. Okay. Did you hear Mr. Smitherman testify that the expectation that is for most wells some go

to the site every day or at a minimum every other day?

A. You know, we probably would do that on our non-stripper wells if we can arrange the pumper schedules. We try to get there every day, certainly, three times a week. You know, the wells that are flowing gas wells that are making 20 MCF a day that don't have any rotating equipment on, maybe weekly. It varies, it varies.

Q. Okay. But I didn't hear Mr. Smitherman, I don't hear you now saying that prudent operators go to sites less frequently depending on the well's volume?

A. They do go to less wells frequently depending on the volume.

Q. They do go less frequently depending on the volume, but they still go frequently; is that right?

A. Yes, yeah.

Q. So as I understood it, Mr. Thompson, your focus seems to really be on the documentation side of things. If I understood you correctly, you suggested that less frequent recordkeeping is appropriate for lower volume wells; is that right?

A. Yes.

Q. But if you are already on the site regardless of the volume of the well, you're going to be checking the numbers. You are already going to be doing the AVOs; is that right?

A. Yes.

Q. Are you aware that OCD inspectors find leaks all the time on well sites that the operators didn't know about?

A. I am sure that happens all the time. I mean, that is why we send operators to locations frequently to fix leaks. I can't tell you that as our operator drives off the location something starts leaking and the OCD inspector follows up. I mean, you might say, "Hey, I caught this thing leaking."

You say, "Well, it wasn't leaking at 10:00 this morning."

It is leaking now, and again, the stuff breaks in the oilfield all the time, that is why we send people to the field all the time.

Q. Exactly. Thank you.

I mean, you know, that is the point I was hoping that you would say.

So Commissioner Engler asked Mr. Smitherman how prudent operators track their

visits and collect data from the wells. Earlier you said that operators, personnel wrote out their key production reports; is that right?

A. Yes.

Q. I think Mr. Smitherman in response to Commissioner Engler said that sometimes these production reports are kept on paper and nowadays they are often kept on laptops or tablets; is that right?

A. Yes.

Q. Does your company use tablets or paper?

A. Apparently we use a system which is called PRAMS, which is on laptops.

Q. On laptops.

So you heard Mr. Powell's testimony at the beginning of this hearing? Did you hear Mr. Powell's testimony or no?

A. No.

Q. You did not, okay. You didn't hear Mr. Powell testify that if the Division does not expect operators to maintain a specific form for their AVOs?

A. I didn't hear that, no.

Q. You heard him testify that an operator can use whatever means they currently use when visiting

the site to track their conduct of an AVO?

A. No.

Q. Okay. So here is my question for you.

Operators are already going to the site frequently. These are already scheduled, they are already conducting AVOs. They are already storing production and other data on paper or laptops depending on the company, using whatever format they may already have.

How exactly will the -- doing what you are already doing or what a prudent operator should be doing require another 1.33 FTE?

A. Well, I think my exhibit was pretty plain where if you have to do the documentation, it is not the AVO inspection itself, it is just the documentation required by this proposed rule is what is going to require a lot more administrative time. And that is the scheduling, actually filling out the form, no matter what kind of form it is. It is not playing in the rules like you pointed out exactly what the Commission is trying to get to.

So I would think that if it is something that the Commission wants us to save for five years, they are going to want it to be detailed enough to be able to say that we monitored something. Like, I

don't know if you find a pinhole in a tank and they go, "How long has that been leaking? Let me see your AVO inspections."

And you have an AVO inspection that says, yes, that doesn't tell you did you walk around and check the tank or not. And so I think you're going to have to have a robust enough inspection form to prove that you checked all the facilities that were cited on the rule. So it is not just a simple thing that you would document on your pumper report every day.

MR. AMES: Thank you. No further questions.

HEARING OFFICER ORTH: Thank you, Mr. Ames.

Mr. Biernoff, do you have questions of Mr. Thompson.

MR. BIERNOFF: Madam Hearing Officer, good morning again. I do not have any questions for Mr. Thompson.

HEARING OFFICER ORTH: Ms. Fox or Mr. Baake, do you have questions of Mr. Thompson?

MS. FOX: We have no questions, Madam Hearing Officer.

HEARING OFFICER ORTH: And, Ms. Paranhos,

do you have questions?

MS. PARANHOS: Thank you, Madam Hearing Officer. We have no questions.

CHAIRWOMAN SANDOVAL: Commissioner Engler, your questioning.

COMMISSIONER ENGLER: No questions, so I appreciate that. Thank you, Mr. Thompson.

THE WITNESS: You're welcome.

CHAIRWOMAN SANDOVAL: Commissioner Kessler?

COMMISSIONER KESSLER: Just one.

EXAMINATION

BY COMMISSIONER KESSLER:

Q. Good morning, Mr. Thompson. You and Mr. Ames were discussing what you -- what your company already does in terms of inspections, AVO inspections. You mentioned that you either use a laptop or some software that your company uses; is that correct?

A. That is correct.

Q. Do you know what happens to those reports? I mean, is it -- are those reports, you know, sent to somebody in the second quarter as already saved?

A. You know, our production foreman and production superintendent review those reports,

monthly. There is some data that we need to get off of those reports in order to fill out C-115s, which would be tank gauges, water production and things that you don't get from the meters. Those are reviewed monthly and then those are served on our server at work.

Q. And do those reports have documentation of AVO already on them?

A. In our Colorado wells we are required to document AVO inspections. But in that case it just has three boxes, you know, AVO, you know, check where you put audio, yes, check audio or visual. And then it has a box for things that you fixed, so I don't think that that would be sufficient for what the NM OCD is requesting.

Q. If it were sufficient, assuming it were sufficient, would there be any additional burdens that your company would be based on different regulations?

A. No.

COMMISSIONER KESSLER: Thank you.

HEARING OFFICER ORTH: Thank you, Commissioner Kessler.

Madam Chair.

CHAIRWOMAN SANDOVAL: Just a couple of

questions.

EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. I was trying to get some numbers, but I didn't quite get there. Maybe my first question is so right now, you know, we are talking about any wells under 60 MCF would be on this, as the Division proposes monthly, as I think NMOGA is proposing quarterly.

Is there a line within that 60 where wells become -- this is like even less economical, you know, like is 60 they are doing okay. We are not doing great, but we are doing okay, whereas, 30 is the part where, like, we are really struggling.

Did you see where my question is?

A. I think it would all depend on your operating costs. I mean, you can have wells that are making over 100 but if you have compression costs and high water disposal fees, et cetera, those wells might not be making any money either.

So no, I think it would be hard to draw a line in the sand based on production.

Q. Okay. I think the Division has proposed for once a month you're doing the T&A wells and NMOGA's is proposing annual. It seems like a pretty

big job. Is there a basis for that jump from monthly to annual?

A. Well, as I read the OCD's regulations for putting a well in T&A status, you know, you have to have a cast iron or a retrievable bridge plug. You have to leave the well full of inert fluid and you probably shut and lock the master valve. So you would have to have all three of those fail before you would potentially have any leaks at the surface. It seems like a pretty remote possibility to me, so I think NMOGA's first preference was to not have to do AVO inspections on T&A wells at all. But based on Brandon's testimony that maybe annually was not totally unreasonable.

Q. It seems like we are getting pretty caught on this term prudent operator. I will ask you a question that is similar to what I asked Mr. Smitherman. Do you believe that all 461 operators in the State of New Mexico are prudent?

A. Probably not.

Q. So do you see some benefit in having this additional structure for proper regulatory requirements to follow for some of those operators who are not prudent?

A. I guess I would hate, you know, I guess my

opinion, if you are not a prudent operator you are not going to be an operator for very long. I would hate to see the Commission have rules that are so onerous to everybody to take care of those people that they inadvertently wipe out some of the more marginal operators, like me.

Q. So I think, I don't remember who it was from the Division, maybe it was Brandon who testified that the time frames were coordinated with NMED with NMED's proposed rule, final rule, and that NMED had the weekly and monthly tiers.

I guess if OCD were to change the frequencies in its rule, could it actually be more burdensome to have two different regulatory frequencies, one for NMED and one for OCD?

A. Well, I'm sorry, I have not seen the NMED's proposal yet. I am not sure exactly what they would be asking as different or the same as the Commission's AVO requirements, sorry.

Q. And do you believe that Brandon also testified that they were -- they matched. So like as you were calling the regular wells it was once a week and for the stripper wells it was once a month.

So I guess my concern is and granted their rule is only a proposal, but would it actually be

more burdensome if OCD were to change their frequency and NMED were to potentially not and that you had a frequency for NMED and you had a frequency for OCD. Would that potentially cause more problems?

A. I think so, yes.

Q. Okay. I also believe I did hear Brandon say that there was -- it was Brandon. Not -- I think the level of maybe taking that required as you may be thinking. Is that, you think, a function of the ruling which is if the ruling was maybe not clear that it is just sort of a minimal, I think we can say concurred or is it a ruling that should not read that way to you? Do you think there is more required?

A. Well, it is not really clear in the rule, I guess, as to what is required, that would be the first point. So I am trying to anticipate what the Commission would ask me for five years from now on an AVO inspection. So I am thinking that if I just had a box that said A, check, you know, B, check; O, check; nothing, nothing fixed; that that really would not be of any value to the Commission.

Q. Okay.

A. But I guess maybe if you could give me an

example of what you would ask me for, three or four years from now.

Q. I can't. You know, that is the Division's proposal. What I recall Mr. Powell talking about was that, for example, if NMED did finalize theirs and publish, this documentation required for NMED that that would meet the Division's needs. There is no set approval above it beyond that, but what I am hearing is maybe the language is not clear enough in OCD's proposal as to what is either required or not for AVO; is that correct?

A. That's correct.

Q. Okay. And if there were -- I think Ms. Kessler got on this some, but would your Exhibit D5 and D4 change if it were as simple as the A, check; B, check; O, check, the burden requirement, do you think those would end up being modified?

A. Well, I think the only problem that we would have to modify would be the search, you know. I mean, if you were to ask me to look at a pumper report for July of 2019, for a particular well we could find that easy enough.

If you were to ask for the AVO inspection report that might have happened through a quarter,

we might have to check two or three different months until we found it. But other than that, no.

Q. So I think this is not -- and Mr. Smitherman testified about this a little bit in neither, or any of the proposals there is a requirement if you were to say, "Finally during the AVO inspection there is no requirement to document that that leak was fixed and how or what," you know, any of those details.

Do you think that that would add a lot of burden to this condition if you were required to also document the fixes, et cetera?

A. I think what that would mean is that someone would do an informal AVO and fix everything the day before they did the documented AVO so that there would be nothing, no corrective actions taken.

Q. Unfortunately, that does not help me. Okay?

All right. That is -- I think that is helpful, but you are saying they could end up circumventing the intent of the proposed rule?

A. Well, I think the intent of the proposed rule is to convince the public that we have people on location taking care of business. And so that would be the whole purpose of documenting the AVO

inspections.

So I don't know that the purpose of the rule is to document everything that a pumper does every day and what we would expect them to do every day as he goes about his business. We recognize that things break in the oilfield all the time and that is why we send people to the field all the time.

CHAIRWOMAN SANDOVAL: Okay. That is helpful. All right. That's all I have got.

Thank you for your time.

THE WITNESS: You're welcome.

HEARING OFFICER ORTH: Thank you, Madam Chair.

Mr. Rankin, do you have any follow-up with Mr. Thompson?

MR. RANKIN: I just have a little, Madam Hearing Officer. I want to make sure I understood Mr. Thompson's testimony on one point with Commissioner Kessler.

FURTHER EXAMINATION

BY MR. RANKIN:

Q. Mr. Thompson, you were discussing an AVO requirement that had a fairly simple form, I believe we just had three check boxes, one for auditory, one

for olfactory and one for visual; is that correct?

A. That is how our system works, yes.

Q. And you're not -- Epic is not required and is not currently conducting a similar checklist for its New Mexico properties; is that correct?

A. That's correct.

Q. So if New Mexico would require similar, very simple checklist such as the one in Colorado, that would be an additional burden on your pumpers in New Mexico, correct?

A. Not much, but it -- because it is just another window that they pop up on the PRAMS system but, yeah, it would be another step.

Q. Okay. But that wouldn't affect looking at your Exhibit D4 and D5, that would be a requirement on your administrative staff to track whether or not those inspections were done and whether or not they were documented and whether or not they were documented correctly. Is that fair to say?

A. That is correct. I mean, they probably would just get filed away with the production report.

Q. It wouldn't change the time element required for those functions at all?

A. Right.

MR. RANKIN: No further questions.
HEARING OFFICER ORTH: All right. Thank you.
Mr. Thompson, before we excuse you, would you please spell out the acronym you have been using which sounded like Pram to me.
THE WITNESS: I'm sorry, I don't know what PRAMS stands for. It is PRAMS. It is like production, reporting and automated -- I don't know, I'm sorry.
HEARING OFFICER ORTH: That is fine, thank you. Any reason not to excuse Mr. Thompson?
Thank you for your testimony, Mr. Thompson. You're excused.
THE WITNESS: Thank you.
(Witness excused from proceedings.)
HEARING OFFICER ORTH: So, Mr. Rankin, or Mr. Feldewert, I see that your next witness is Mr. Iannuzzi?
MR. RANKIN: Madam Hearing Officer, that's correct. The next witness on our list is Ms. Morgan Iannuzzi, and I am going to see if she is on yet, in fact, I don't see her yet.
HEARING OFFICER ORTH: Any reason we can't finish at least the direct presentation of

Ms. Iannuzzi before lunch?

MR. RANKIN: We will give it a good go.

(Whereupon, the witness was sworn.)

HEARING OFFICER ORTH: Go ahead, Mr. Rankin.

MORGAN IANNUZZI,

after having been first duly sworn under oath, was questioned and testified as follows:

EXAMINATION

BY MR. RANKIN:

Q. Ms. Iannuzzi, will you please state your full name for the record.

A. Morgan Ann Iannuzzi.

Q. For the benefit of the court reporter, would you please spell your name.

A. Sure. Morgan, M-O-R-G-A-N. Last name I as in igloo, A as in apple, N as in Nancy, N as in Nancy, U, Z as in zebra, Z as in zebra, I as in igloo.

Q. Thank you very much.

Would you please let us know by whom you are employed and in what capacity?

A. Sure.

I work for Chevron and I am the mid-continent business unit air team lead.

Q. Ms. Iannuzzi, I am going to ask you to refer to what has been marked as NMOGA Exhibit E.

Does Exhibit E1 accurately summarize your educational background and work experience?

A. Yes, it does.

Q. And, Ms. Iannuzzi, is your testimony going to address NMOGA's proposed modifications to the Division's definition of emergency in Part 27 as well as the proposed modifications for the flash requirements?

A. Yes.

Q. Would you please briefly summarize your experience and education working and overseeing flares and flare operations and also reporting related to flaring and venting events?

A. Sure.

So I have worked for Chevron for almost ten years in various health, environment and safety positions. And about five years of that has been working on air issues.

In my current role I am the air team lead, which means I am responsible for air permitting. And we cover Texas, New Mexico, Colorado and we have got a little bit left in Oklahoma. So I oversee a team of folks that is responsible for the day-to-day

flaring and venting reporting.

I have also been involved in developing guidance for flares, specifically flare design to minimize environmental impact. And I have also helped produce some guidance around minimizing flaring and venting in the mid-continent business unit.

Also regards to operations, I was out in the field supporting field operations for a couple of years specifically at a gas plant in Central California.

Q. And are you familiar with the modifications that NMOGA has proposed for Part 27 as it relates to flaring and their requirements?

A. Yes.

Q. You are also familiar with the modification that NMOGA is proposing that addresses the time frame that would fall within the definition of emergency under Part 27 rule?

A. Yes.

Q. And, Ms. Iannuzzi, does the NMOGA exhibits contain exhibits that you have prepared explaining these proposed modifications and the justifications for them?

A. Yes.

Q. So let's go ahead and get started with the definition of emergency.

And for the benefit of the Commission and others, again, I will do my best to put up the language on the screen so that it is shared and you can actually track the language as we go through both the OCD's proposals and NMOGA's proposed modifications.

Let's start with, again, starting with the definition of emergency. I am going to pull up on my screen the language that the Division is proposing. If you would, Ms. Iannuzzi, would you just review what it is that the Division has proposed here for the definition of emergency that you will be addressing.

A. Sure.

I don't see it up on the screen, yet.

Q. That is because I didn't click share.

So you will see along with Page 1 of OCD's Exhibit 2A this is the definition of emergency under Subpart G.

Do you see that?

A. Yes.

Q. And I will scroll down to Subparagraph 4 under that paragraph. Would you review what it is

that the OCD is proposing in terms of the time frame for these emergencies?

A. Sure.

NM OCD is proposing that any venting or flaring that is caused by emergency unscheduled maintenance or malfunction of a natural gas gathering system that is less than four hours after upstream is notified does not count as -- or does count as an emergency.

Q. Now, I am going to ask you, I am going to switch over to NMOGA's proposal. In that definition, in that same definition -- sorry for making everybody sick.

And, Ms. Iannuzzi, would you review for the Commission what it is that NMOGA is proposing in terms of modifications to this definition.

A. Sure.

NMOGA is proposing that the first eight hours of venting or flaring shall be considered an emergency, so increasing the time frame from four hours to eight hours.

Q. Okay. Now, Ms. Iannuzzi, I will ask you to refer to what is marked as Exhibit E2 in NMOGA's exhibit binder. If you would, just explain why it is using your exhibits as a rationale to explain the

rationale logic behind NMOGA's proposed preference for eight hours versus the four hours as the division has proposed.

A. Perfect.

So looking at this exhibit, we asserted a hypothetical response timeline, and you can see that our zero starts with notification, so that aligns with NM OCD's proposal.

So as soon as that notification is received that there is an emergency, unscheduled maintenance or malfunction, that kicks off the timeline. So within that first hour that one of the first things that upstream will do is reach out to midstream to find out what is going on. There is certain information that is helpful in the figuring out next steps and that information includes the preliminary cause, area of impact and anticipated duration.

This information is helpful in figuring out next steps. And sometimes, midstream doesn't know everything because they are having an emergency themselves, but it is helpful to know that preliminary cause.

And then we have an hour for the field operator arrives on site. And that is totally

reasonable, I was shocked at how far everything is spread out in the Permian Basin when I moved here about three years ago.

In California things are a little bit closer together and so it can easily take an operator two hours to reach the site. And so if you think about that in the four-hour time frame, 50 percent of your response time is just dedicated to driving.

But once the field operator gets on site they will get out of their truck and determine what they need to do. If it is shut-in or are there other mitigated measures. I believe some of the other NMOGA witnesses have testified that there are other things that an operator can do.

For example, they might be able to switch to another midstream provider to send that gas or they might be able to reinject the gas. So there is other potential alternatives to just, okay, we need to shut-in. We need to sort of evaluate the situation and decide the right course of actions.

And, let's assume that the right course of action is shutting in. And we have got a four-hour lag between hour three and hour seven. And why do we have a four-hour lag? Because there are certain

procedures that must be followed in order to shut-in the wells.

I have been working very closely with our operations group to minimize the time that we are flaring and venting. And the time that we decide to shut-in to the time that we actually have stopped producing, there is a lag there, so we wanted to acknowledge that in this hypothetical.

And then the last little time lag is between shutting in and actually stopping flaring on venting. There may be some gas left in the system, and so that may cause some additional flaring and venting. Additionally, depending on the facility and the time of day and the summertime, if we have got oil left in the tanks there may be some intermittent flaring due to the tanks heating up and there would be some off-gassing.

Q. Now, Ms. Iannuzzi, we reviewed the OCD's updated modifications to its original proposed rule. What changes did the Division make to its updated revisions that we in response apparently to some comments?

A. So in their response into some comments they added that "after notification" and they struck the "as defined in 19.15.28."

So those were the two changes and I really appreciate their "after notification" because that aligns with NMOGA's understanding that that is when the response time kicks off is once the notification is received.

Q. Now, does that change their modification to what the rule proposes, have any impact on your analysis in terms of the time requirement to respond and resolve one of these upstream upset events?

A. No. It aligns with our original assumption that our timeline kicks off with notification.

Q. So in your opinion, Ms. Iannuzzi, is four hours as proposed by the Division a reasonable time frame to impose on all New Mexico operators to respond and resolve to one of these events so that volumes vented or flared due to events caused by an upstream upset which are outside their control are not counted against the operator?

A. No, the key word in there is "all."

All of these events are going to vary and that is one thing that we can rely on is some events will be able to be responded to in less than four hours, but some will not, especially those with drive times. So eight hours is more reasonable.

Q. And I think you have touched on this, Ms. Iannuzzi, but on the bottom of your slide there are some factors that you have identified. You talked a lot about the distance here and some of the other operational considerations. There are some other factors that would play into the time frame here as well. Would you just touch on those a little more detail before we move on?

A. Sure.

Mr. Smitherman also touched on these as well, so I will try to keep this brief.

Number one, is inclement weather. If it is raining, snowing, icy weather conditions, that can have an impact on how quickly we are able to respond.

Road conditions, Mr. Smitherman mentioned some roads are unpaved and you need to go slow.

Operating conditions, I think this is a big one and I sort of touched on it in the timeline, is sometimes you can't just flip a switch and shut-in. It really depends on what is going on at the facility, at the time, so that is a key factor in determining what is the appropriate course of action.

The other one I touched on is distance to

site. Time of day also matters. If this happens at 2:00 in the morning is going to have a very different response time than at 2:00 in the afternoon.

One thing that John Smitherman mentioned was the status of utilities and communications. There are portions of New Mexico that we do not have any cell phone service. So if we do need to reach out to that midstream operator or if we need to coordinate with just among ourselves with our supervisors and our field coordinators, that can be challenging when you don't have cell phones.

And the last one is alternate means of gas takeaway, which I touched on around what else can we do with the gas rather than flare or vent it.

Q. So now, following up on this change that NMOGA proposes, there is a corresponding change that would be required in the rule language as well at Part 27.8G.2; is that correct?

A. That is correct.

Q. So I am going to share my screen now. I am going to take you to that. It is in NMOGA Exhibit A at Page 20.

Ms. Iannuzzi, do you see my screen now?

A. Yes.

Q. Would you just confirm that this is the change that corresponds to the change in the time frame definition that we just reviewed?

A. Yes. This is under the reporting section and it just aligns with the definition.

Q. Now, I want to talk a little bit about something that has come up during the course of this topic and the testimony in this hearing. And that is the discussion, rather the potential for having two time frames within which operators can respond and resolve upstream upsets and not have those additional volumes count against them.

Are you familiar with the testimony and the discussion around that topic?

A. Yes. I was listening in.

Q. Okay. And you heard some discussion around the term SCADA or -- is that my understanding is it stands for Supervisory Control and Data Acquisition Systems. You heard the testimony around that?

A. Yes.

Q. And then also the idea of having some wells and facilities may have a remote shut-in capability?

A. Yes, yeah.

Q. Now, you don't have any expertise in SCADA or remote shut-in or any of the requirements around operating those or best management practice for how those should be implemented?

A. No. My background is environmental.

Q. Okay. So your experience here is just to recording of the time frames required to get a flaring event attended to and resolved; is that right?

A. Correct.

Q. But, do you have some comments or responses to the discussion around the proposal to have two different time frames?

A. Yes, yes.

Q. What are they?

A. So I really appreciate the intent of adding some flexibility because they are very different scenarios, however, my team is responsible for training operations on what they need to report.

And we have found that keeping it simple and straightforward helps to improve the accuracy of reporting which has been touched on in previous testimony and different times for different facilities produced at some unnecessary complication. So my recommendation would be to keep

it simple and go with just one recommended or one time frame.

Q. And now, you're not -- because you are not an operations person so you may not know this, but is it as soon as possible depending on how broad an upset is that there may be a mix of wells that have remote shut-in capabilities and some that don't that are being impacted by an upstream event or rather a downstream event?

A. Yes. So when midstream has an upset, that typically causes upstream to flare or vent. In Chevron's case it is normally flaring and we use what are called centralized tank batteries. And that means that there are multiple wells going to one facility, so many wells can be affected depending on the scenario.

Q. Okay. And as far as you know, some of those wells may or may not have remote shut-in capability or not?

A. Correct.

Q. So that is part of -- I think, is that part of why you are suggesting that there only be one time frame because you have different time frames for different wells, facilities, all impacted by the same event?

A. Yes. So we could have one facility and one flare, but we would have multiple wells going to that same facility and some of them could be able to be remotely shut-in and some might not be able to and so what time frame do we go with could be a question that comes up. So it is easier to go with just one time frame.

Q. Okay. So now, I think I want to move on to the next topic of your testimony, which is around the Division's proposed flare stack requirements.

I will stop sharing my screen.

What are the three areas or topics that you will be discussing today regarding the flare stack requirements?

A. I will be covering enclosed flares and citing, flaring efficiency and retrofitting ignition systems. And the third one is using construction dates and not spud dates for determining scope.

Q. So some of these have been addressed at a high level by Mr. Smitherman. Where possible we are going to try to skim over them as quickly as we can. Okay?

So let's look at the first topic, enclosed flares and citing that you raised. Have you reviewed the Division's modifications to its

proposal for Part 27.8B2 in NM OCD Exhibit 2A at Page 2 of that exhibit?

A. Yes.

Q. And I am going to share that on my screen. Do you see it now, Ms. Iannuzzi?

A. Yes.

Q. If you would, just review briefly what it is that the Division is proposing in its updated language and the -- so that we have an understanding of what is at issue.

A. NM OCD is proposing adding the phrase, "Unless otherwise approved by the division," and striking all other language.

Q. Okay. And what is the position generally on flaring versus venting?

A. So NMOGA recognizes the importance of minimizing surface waste and we have a shared goal with NM OCD to reduce volumes. And we are in alignment with the 98 percent capture rate.

Additionally there are also safety benefits to flare as opposed to vent, but it is important that whatever rule the Commission ultimately adopts needs to be realistic and achievable. It should not impose requirements that even the EPA recognizes in its guidelines that

cannot be consistently achieved.

Q. When you talk about those guidelines in EPA, you are talking specifically about flare stack requirements; is that correct?

A. Yes.

Q. Okay. We will talk about that in more detail, but that is the overall kind of approach here.

Now, looking at -- let's see, so on that first section, on Part B2, what is it that -- what is NMOGA's position on those recommended modifications by with the Division?

A. NMOGA supports that addition of, "Unless otherwise approved by the Division," and striking of, "Shall be enclosed."

Q. Okay. And now, briefly, if you would, referring to what has been marked as Exhibit B3 if you could kind of just highlight the high-level basis for support on that, of those changes.

A. Sure.

So enclosed flares have some limitations, and they can be great in certain situations but this is specifically referring to drilling operations. And enclosed flares have capacity constraints.

In NM OCD's Exhibit 41 which is EPA's

flare design document on Page 6, it says that, "Enclosed flares generally have less capacity than open flares and are used to combust continuous constant flow vent streams."

And in drilling operations you don't have those continuous constant flow vent streams.

They are typically used for emergency situations. And, again, they generally have less capacity. So the enclosed flares aren't, in my opinion, appropriate for drilling operations.

Additionally, the term they cannot -- challenges with ensuring adequate air flow because it is enclosed as we are all probably familiar with fire, fire needs air and so there can be challenges with keeping the flame lit.

And finally it does not reduce the volume of gas flared, determining whether it is an enclosed flare or an open flare. The volume of gas will be the same going to the flare. So the waste is going to be the same and there is no additional emissions reduction benefit.

Q. Okay. So as to this portion of the rule, then, NMOGA supports the changes that are being proposed by the division as to this, right?

A. Yes. So we support the, "Unless otherwise

approved by the Division," and the striking of, "The enclosed."

Q. Okay. Now let's look at the second topic you are going to talk about, flaring efficiency and retrofitting the ignition systems. I am going to direct you down to the same portion of the rule to Subpart E, E3. If you would, just review what it is that NM OCD is proposing here for its updated rule language.

A. Yes. So what NM OCD is proposing requiring is that, "The operator shall combust the natural gas in a flare stack that is properly sized, designed, and operated for complete continuous combustion of gases sent to the flare."

Q. Now, you testified previously that in general NMOGA supports flaring over venting, but that there is concerns around imposing something that EPA doesn't require; is that right?

A. Yes, that is correct.

Q. Okay. So tell me a little bit about what is the significance of the language here in this proposed rule that would require a flare stack to be designed and operated for complete and continuous combustion.

A. Sure.

So the thing that is holding up NMOGA is around the, "operated for complete and continuous combustion." The way that I am interpreting the Division's proposal is that they would require 100 percent of combustion, 100 percent of the time during operations.

And even according to NM OCD's own exhibit, again, this is Exhibit 41, Page 4, they say that, "Combustion is complete if all the VOCs, volatile organic compounds, are converted to carbon dioxide and water."

So we are interpreting this complete, combustion to mean 100 percent.

Q. Got you. Now, is in the -- in real life out in the field is continuous 100 percent combustion possible under normal operating conditions?

A. No. This is not possible under -- to be operated at 100 percent combustion.

Q. Okay. So if you would, Ms. Iannuzzi, just referring to Exhibit B4 in NMOGA exhibit packet, you just review for the Commission some of the concerns around that language?

A. Sure.

So first, let's talk about what is

destruction efficiency. And destruction efficiency is an air emissions matter, not a prevention of waste. A destruction efficiency is talking about how effected the flare is. I am sure we all love a good chemical formula as some of us are engineers, so I put what happens with combustion just to remind everyone that you take a hydrocarbon such as methane, you add oxygen and in the perfect scenario all you end up with is carbon dioxide and water.

So the EPA defines destruction efficiency as the percentage of a specific pollutant in the flare vent gas that is converted to a different compound, such as carbon dioxide, carbon monoxide or some other hydrocarbon intermediate.

So that destruction efficiency is referring to how much of the hydrocarbon is converted into carbon dioxide.

Q. Just to be clear, because you are talking about destruction efficiency in your exhibit. The Division uses the term complete combustion. You are equating the two in your analysis here; is that right?

A. Yes. As you can see in the original language of the rule, they were using both the phrase maximum efficiency which we were also

interpreting to be 100 percent. That is generally what we are talking about when we are talking about efficiency in general.

Q. Very good. Now, I think I asked you and I think you answered this, but essentially in real world conditions you cannot achieve complete and continuous combustion. What are some of the factors that would play into, you know, achieving complete and 100 percent complete combustion efficiency?

A. So the factors that came to my mind when I was first looking at this was, number one, the gas flow rate, how much of the gas is flowing to the flare.

The gas composition itself such as the heating value, the air to fuel ratio, the type of flare. There are a lot of different types of flares. We talked about enclosed flares earlier, but there is also flares that add assist gas or steam, so that determines how efficient your flare is as well as ambient conditions such as wind and flame.

And even going back to NM OCD's Exhibit 41, Page 7, they state that the major factors effecting flare combustion are vent gas flammability, auto ignition temperature, heating

value, BTU per scuff, density and flame zone mixing.

Q. Very good.

MR. RANKIN: Madam Hearing Officer, I am just noting the time that it is noon. I don't think that we have enough time here that would make sense to take a break at some point.

That is the end of this slide so I wonder, we are at a natural break now, so are we going to take a break for lunch now or what is the Commission's preference?

HEARING OFFICER ORTH: All right. Let me see.

(Discussion off the record.)

HEARING OFFICER ORTH: Let's break, and is a half hour enough for folks?

Let's come back at 12:35. Thank you all.

(A recess was taken from 12:02 p.m. to 12:39 p.m.)

HEARING OFFICER ORTH: Let's see. Mr. Rankin and Ms. Iannuzzi, please resume.

Q. (By Mr. Rankin) I must have been thinking about my lunch, because I didn't permit you the time to finish the last point on your Slide Number 4.

So if you would, just resume before I cut you off, to discuss the last part of your Slide

Number 4. And if you would, just explain how that relates to the topic of the slide and the concerns that NMOGA has regarding the division's proposal.

A. Sure. And so the last point that I wanted to make was around the EPA control technique guidelines for the oil and natural gas industry.

These guidelines were developed in 2016 to help state, local, and tribal air agencies with information to help them determine reasonably available control technology for volatile organic compounds via the emissions.

And they were targeting ozone nonattainment zones, so it is relevant to these discussions.

And they had a quote in there that says that while flares can be designed for 98 percent control, it says we also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet the sufficiency in practice due to factors such as the variability of field conditions.

And so that just goes ahead and further supports our point that complete and continuous combustion is not achievable.

Q. So going back to the language of the

commission's proposed rule. Just as a reminder, the language imposes a requirement that flare stacks be properly sized and designed and operated for continuous operation, correct?

A. Correct.

Q. So just tell me a little bit about -- now explain the difference between, you know, what is essentially a design standard or requirement and what an operator standard would require for flares.

A. Yes. So flares can be designed so that they burn at a certain efficiency. John Zink is a very well-known flare manufacturer, and they generally state that their flares meet 98 percent design efficiency.

But when you get out into the field things don't always go as planned. And to be continuously operated at those design standards in real world conditions is just not achievable.

Also, I want to bring back to complete combustion. I mean, it goes back to -- to kind of just your basic laws of thermodynamics, where you can't have 100 percent combustion. It just doesn't happen.

So you've got your design of what it's intended for, and then you have your operation of

what it actually experiences.

Q. So in your opinion is it unreasonable, then, to impose the same standards for flare operations as for flare design?

A. Yes.

Q. It's not something that EPA imposes on anybody.

Is that fair to say?

A. Right. The EPA does not require flare operations -- flares to be operated at a certain efficiency.

Q. And here, will the combustion standard that OCD is proposing have any impact on the minimization or reduction of surface waste?

A. No. What I view as waste is the volume of gas. And the volume of gas that is flared is not going to change, no matter how efficient your flare is. It could be 100 percent efficient. It could be that magical flare. But the volume of gas that is not captured will remain the same.

Q. Now, let's turn to what -- in -- referring to NMOGA Exhibit A on page 11.

And I'll share with you my page, so that you can see NMOGA's proposed language.

If you would review for the commission

what it is that NMOGA's proposing be placed instead of the division's proposed language.

A. NMOGA is proposing to ensure proper combustion of gases, such as a flare.

Q. Now for all the reasons you stated, for purposes of this rule and its goal of reducing waste, is it your opinion that this is a better language, or preferred language, than what the division has proposed?

A. Yes.

Q. And to your earlier point, in your view this is language that is achievable and reasonable in the real world conditions?

A. Yes. It is a slight language change between complete and proper. But it makes it an achievable goal.

Q. Now with their topic that we're going to discuss today in your testimony, and you've identified, is the retrofitting issues.

And if you would, I would direct you to NMOCD Exhibit 2A. And I'll put this up on the screen so you can see it.

I believe it's at E3B.

Do you see there -- this is OCD Exhibit 2 under E3 little B.

Would you review for the division what the -- sorry.

Would you review for the commission what it is that the division is proposing in terms of retrofits?

A. Sure. It adds the -- the NMOCD added commas for clarity, after auto igniter continuous pilots, to make it clear that there are three separate technologies that can be used, and switched the "has" to "may have," because -- just because the technology is indicating that something may be wrong doesn't always mean that something actually is wrong.

Q. And NMOGA agrees and supports those changes?

A. Yes.

Q. Okay. Now, tell me where -- about the timing here for retrofit. What -- do you see -- does NMOGA have any issues for our proposed modification for the timing that's being suggested here by the rule?

A. Yes. So the division is proposing that the rule be applicable to all existing flares installed before June 1, 2021. And those flares would need to be retrofitted to comply with the

rule.

And so NMOGA has proposed an alternative, instead of an 18-month deadline to retrofit those flares, to be a 24-month deadline.

Q. Okay. So that would be an addition of another six-month time frame to -- to meet those retrofitted requirements?

A. Yes.

Q. I will go ahead and bring that language up here. I believe it's on -- that would be Paragraph 3, little B. And that's the language indicated on the redline on the bottom of this page.

Is that correct?

A. Yes.

Q. Okay. Now, there's some additional redline in there as well. What else are you proposing as a modification to the rule?

A. In addition to the 24 months instead of 18 months, NMOGA had added "or by an alternative date approved by the division."

This allows a mechanism, in case an operator cannot meet that deadline, that the division can approve some other approved deadline.

Q. So let's -- let's talk about the issues around meeting the time frame, then.

You've got a slide marked Exhibit B5. Would you just review for the examiners, what are the challenges that NMOGA perceives in terms of being able to meet that time frame and why they're asking for an additional six months?

A. Sure. So retrofitting, we need to look at the entire process from start to finish. And there are a lot of different steps in that. It's not just the installation time.

The first thing that comes to mind is that the manufacturers actually need to produce those ignition systems. And if all operators in New Mexico are all clammering for auto igniters and continuous pilots, that could cause a strain on the supply chain.

And then operators have certain steps that they need to go through in order to make those retrofit changes.

Number one, they need to allocate capital resources. That's typically an annual cycle, so we need to build it into our budgets.

Number two is engineering systems. And in my opinion, that's probably the most important step, is making sure that we have the right ignition system for the right flare. You need to think, is

an auto igniter right for this case, or would a continuous pilot work better?

Then you've got your installation, which is what you would normally think about. And normally, that installation is completed by a contractor. So again, you might have a competition for limited resources, similar to the manufacturing issue.

And finally, we need to train our employees on the proper use. They need to know what the ignition system is designed to do. And if they get an alarm, what are they supposed to respond to?

There's other thing that we need to do, like updating our piping and instrumentation diagrams, so that our process safety information is correct for each site.

So there's a lot that goes on behind the scene in a retrofit such as this.

Q. Now, there's one other area in which there were some additional modifications on the topic of your -- your testimony. And I'll switch back over to OCD's Exhibit 2A. And I believe it's at E4, where there was -- let me know if you can see that here -- where there's a language change deleting "located at a well spud," and replaced with the word

"constructed."

Would you just review the significance of that language and NMOGA's position on it?

A. Yes. So NMOGA supports this change, so I'll start off with our position.

This is a good change because, really, the applicability is all about the flare stack construction date.

As we talked about in the previous one, we talked about the installation date, construction date, that's similar.

But the well spud, and when the well actually starts producing, may not be applicable.

As I've mentioned earlier, Chevron uses centralized tank batteries, so you've got multiple wells that might all be connected to one flare. So what date do we end up using?

So focusing in on the flare makes it much more straightforward.

Also, adding "unless otherwise approved by the division" allows flexibility as appropriate in those instances where 100 feet may not be workable or feasible in that situation.

Q. Very good. Thank you very much, Ms. Iannuzzi.

Now I'd like to talk about some of the other parties' modifications that were proposed.

Have you had a chance to review EDF's proposed modifications to Part 27 of the rules?

A. Yes.

Q. In particular, EDF's proposed modifications to Part E in 27.8E3 little E?

A. Yes.

Q. Let me see if I can get us there and share my page so we can look at the language.

I believe I've got it up on the screen.

Can you see here where this is EDF Exhibit 4, at page 4 of that exhibit?

Do you see the language of that highlighted with my cursor?

A. Yes.

Q. Would you agree -- I'm sorry.

You have reviewed this language?

A. Yes.

Q. And tell me what your position is, or NMOGA's position is on this proposed change and the time frame suggested.

A. So what EDF is proposing is to decrease the time to retrofit from 18 months to 6 months.

And that isn't reasonable, considering all

of the different factors, as I just previously explained. We need to think about the entire process of making modifications.

Q. And would accelerating that time frame in the proposal do anything to minimize or reduce surface waste?

A. No. It's not going to reduce the volume of gas going to the flare. What having an automatic ignition system or one of the other ignition systems will do is ensure reliable combustion.

And so the only justification for shortening the time frame is to address air emissions.

The other thing that I want to point out is that EDF does not allow for any flexibility if the operator cannot meet this time line, and that was what NMOGA proposed by adding the phrase "or by an alternative date approved by the division."

Q. And the same -- same essential issues arise with EDF's proposal for Subparagraph C as well.

Is that correct?

A. Yes.

Q. All right. The same thing. As I said, the time frame issue. And then also, it does not

begin to reduce surface waste?

A. Correct.

Q. Now, there's some additional language changes by proposing new language.

Have you reviewed that language in the same part on page 5 of Exhibit 4?

A. Yes.

Q. And I've highlighted it here. It's the redline under Paragraphs 8 and 9.

You just reviewed for us what that language proposed to do, and also your concerns, NMOGA's concerns, with the requirements contained in that language.

A. Sure. So let me start off with Number 8, which states:

"Operators shall submit to the division an engineer's certification that all flares or combustors will have sufficient and consistent gas flow and keep content to achieve the manufacturer's designed destruction efficiency."

So NMOGA's interpretation on that is that a professional -- or a registered professional engineer would need to state that the designed destruction efficiency would be met in operation.

And I am not a registered professional

engineer. But I would be challenged to be able even to state that, yes, this flare will meet the design efficiency, because it's very difficult to predict what operating conditions, such as gas flow and heat content, will be.

A lot of times we use flares in emergency situations. And so being able to say that we are able to meet certain design standards would be challenging.

Q. Doesn't that just go back to the guidelines you discussed earlier of the EPA, if there's not an expectation that a flare can operate at its design efficiencies?

A. Yes. It cannot operate at its design efficiency continuously.

Q. So now the division has not reported their proposal to adopt this language.

Do you agree that -- with the division that such a requirement is not appropriate and should not be adopted here?

A. Correct. This language should not be adopted. It's focused on emissions issues, but not reducing the volume of gas going to the flare.

Q. Okay. That's true for both of these provisions, correct?

A. Correct.

Q. Now -- okay.

I think the next thing to talk about would be Climate Advocates. Is there anything further on EDF's proposed language on these topics that I've missed, Ms. Iannuzzi, that we need to discuss?

A. I think we should go back to E9 and look at that in detail.

Q. Okay.

A. E9 states:

"All flaring during completion and production shall be done with an enclosed device that has a design destruction efficiency of 98 percent."

And I want to reference my earlier testimony that enclosed flares are not always -- or enclosed devices are not always the best. Because many flares exist for emergency purposes, and enclosed flares have capacity restraints. They also have issues ensuring adequate airflow, especially for the center of the flame.

So this -- this could be an inappropriate requirement.

And it does not reduce the volume of gas going to the flare by requiring it to be enclosed.

So it's really an air quality issue.

Additionally, if you look at it, it's going to require that all flaring is to be done in an enclosed device. So the way that I'm interpreting this is that we're going to have to retrofit all of our open flares, and there are quite a lot of open flares.

And so the -- this could result in undue and unnecessary burdens that aren't minimizing surface waste.

And then the other requirement around the design destruction efficiency, I think I've spoken at length around design efficiency and how that is an air emissions issue, as opposed to minimizing waste.

Q. Got you. Okay. Good. I'm glad you brought that up.

Is there some -- let's see. I think that's all we need to cover on that.

Let's see. Now, on -- on the Climate Advocates' proposed changes, do they generally track what EDF has proposed as well?

A. Yes. So Climate Advocates has approximately three changes that are related to my testimony.

Number one, they require flares to have a destruction removal efficiency of at least 98 percent. And you can find that in Part 27.8B2, Part 27.8C1, Part 27.8D.5 little I, Part 27.8E3A.

So those all refer to having a destruction removal efficiency of at least 98 percent.

The second thing that's related to my testimony is eliminating the option for continuous pilot or other technology that alerts the operator that the flare stack may have malfunctioned.

And you can find those references in very similar places: Part 27.8B2, Part 27.8C2B, Part 27.8C3A, Part 27.8D.5 little I, Part 27.8E3A and E3B.

All of those have that strikeout of continuous pilot or technology that alerts the operator and removes those two options.

And the last thing is -- right there. You don't have to scroll at all, Adam -- is Part 27.8E3B, which reduces the time to retrofit ignition systems to 120 days, or four months.

Q. And for all the reasons you've testified, that time frame is all the more less reasonable given the constraints and the issues of combustion. Is that right?

A. Yes.

Q. Okay. Now, you've brought up the point that Climate Advocates is proposing to delete the continuous pilots.

Is that right?

A. Yes. Yes.

Q. Does NMOGA have concerns with requiring only automatic igniters, as it is -- that are being approved under the rule?

A. Yes. And if you take a look at my Exhibit E5, all three types of ignition systems are reliable to ensure the combustion of gases.

And so we need the flexibility to select the right one for the specific operational scenario.

Also determining what types of ignition systems there are. If it's an air emissions issue, it does not reduce the volume of gas that is not captured.

Q. And just to summarize, going back on the time frame.

NMOGA's proposal is for 24 months, right?

A. Correct.

Q. And you think that's a workable achievement time frame for industry in New Mexico to obtain -- to achieve these compliance requirements

for retrofitting?

A. Yes.

Q. More workable than either what the division or these other parties are proposing?

A. Yes.

Q. Okay. Now in your opinion, do NMOGA's proposed revisions, the proposed rules of reducing surface waste -- without imposing undue and necessary burdens on operators?

A. Yes.

Q. Were Exhibits E1 through E5 prepared by you or under your supervision?

A. Yes.

MR. RANKIN: At this time, Madam Hearing Officer, I will move the admission of Exhibits E1 through E5 for the record.

HEARING OFFICER ORTH: Let me pause for a moment, in the event there are objections to NMOGA Exhibits E1 through E5.

No?

(Exhibit admitted, E1 - E5.)

E1 through E5 are admitted.

MR. RANKIN: At this time, Madam Hearing Officer, I will pass the witness for questioning.

HEARING OFFICER ORTH: Thank you,

Mr. Rankin.

Mr. Ames, do you have questions of the witness?

MS. POLAK: Madam Hearing Examiner, this is Tiffany Polak.

I need to make you aware that Mr. Ames lost internet capability. He is on the phone. So if Mr. Garcia can allow him to be unmuted on the phone, I believe he will be able to speak.

HEARING OFFICER ORTH: Thank you very much, Ms. Polak.

Mr. Ames, we can hear you.

Do you have questions of Ms. Iannuzzi?

MR. AMES: Thank you, John, for letting me in.

I do not have any questions for Ms. Iannuzzi. Thank you.

HEARING OFFICER ORTH: All right. Thank you.

Mr. Biernoff, questions of Ms. Iannuzzi?

MR. BIERNOFF: Madam Hearing Officer, I do not have any questions for Ms. Iannuzzi.

HEARING OFFICER ORTH: Thank you.

Ms. Fox or Mr. Baake?

MR. BAAKE: Madam Hearing Officer, I do

have questions.

And Ms. Fox and I are going to be switching back and forth probably for the most part. So...

EXAMINATION

BY MR. BAAKE:

Q. Ms. Iannuzzi, am I saying that correctly?

A. Yes.

Q. Okay. Great. I just have a couple of questions.

First of all, I'm looking at your CV here. And it looks to me that your background is in engineering, correct?

A. Yes. I have a bachelor's of science in environmental systems engineering from Penn State.

Q. But you don't have a law degree.

Is that correct?

A. That is correct.

Q. Okay. So to the extent that you opine that certain issues -- or air quality issues, but not necessarily waste issues, that would not be persuasive as to what OCD's authorities are. It's not a legal opinion, in other words?

A. Yes. Legal questions are outside of my area of expertise. But I do have extensive

experience with environmental issues. And so I take the basic generic definition of waste meaning the volume of gas as opposed to air emissions, which are the emissions resulting from flaring and venting.

Q. Understood.

And I -- I wanted to ask you: Are you familiar with Colorado's regulations related to the fresh air acts?

A. I have a general awareness. I'm not an expert.

Q. Okay. Fair enough.

Would you agree, or are you aware, that Colorado's rules do require auto igniters for all their flares?

A. I believe I have heard that.

Q. Okay. And so I think you tes- -- and this is actually just a completely -- a question that is based on the fact that I didn't hear you.

I think you said you had an exhibit, and I don't remember which one, that suggested that all three of the technologies were equally reliable.

What was that exhibit again?

A. So I didn't go into it in detail. It's Exhibit E5. I had originally planned to talk more at length around the three different technologies

for ignition systems, but that has been covered extensively by prior witnesses, so I kind of cut that out of my testimony.

Q. Understood. And we do have the exhibits we can look at, so I appreciate that.

My question is: If that is true, that they're all equally reliable, do you have any idea why Colorado and other regulators might require only the auto igniters?

MR. RANKIN: Objection. It calls for speculation, and it's outside the scope of Ms. Iannuzzi's testimony.

HEARING OFFICER ORTH: Yes, Mr. Baake?

MR. BAAKE: Let me see if I can rephrase that.

I think it -- it's within the scope of her testimony, because she testified that they were all three equally valid. But I understand she can't testify as to what Colorado regulators might have thought.

Q. (By Mr. Baake) So would you agree that auto igniters are generally considered to be the most reliable of those three technologies?

A. No, I don't know if I would agree with that. In fact, the EPA requires continuous pilot,

according to 60.1E.

So if the EPA requires continuous pilot, I would assume that they are relatively reliable.

Q. Okay. You wouldn't necessarily have a ranking of those three technologies?

A. No, I would not.

MR. BAAKE: Okay. All right. I think I'm done.

I will pass. Thank you so much.

HEARING OFFICER ORTH: Thank you, Mr. Baake.

Ms. Paranhos?

MS. PARANHOS: Thank you, Madam Hearing Officer. I do have a few questions for the witness.

EXAMINATION

BY MS. PARANHOS:

Q. Good afternoon, Ms. Iannuzzi.

A. Good afternoon.

Q. I have a few questions.

Are you aware of EDF studies in the Permian Basin finding unlit and partially lit flares?

A. Yes.

Q. Do you agree that a partially lit or an unlit flare releases more methane than a properly

functioning lit flare?

A. Yes.

Q. And do you agree that installing auto igniters or continuous pilot lights on flares can help reduce the incidence of partially lit or unlit flares?

A. Yes. Certainly.

Q. Do you agree that a flare that is designed and operated to achieve the design destruction efficiency of 98 percent releases less methane than one that is designed to achieve a lesser destruction efficiency such as, for example, 70 percent?

A. Yes. But it really goes back to what -- the design efficiency is all about how effective the flare is. And again, my understanding of this rule is to prevent waste.

And so requiring that does not prevent the loss of gas. And so really, the focus should be on reducing the volume and focusing on driving that 98 percent capture rate.

And that's what we want to focus on.

Q. I understand that that's NMOGA's position. I believe OCD and other parties have a different understanding of what are the goals of the rules.

MS. PARANHOS: But those are all my

questions. Thank you very much for your testimony.

HEARING OFFICER ORTH: Thank you, Ms. Paranhos.

Commissioner Engler, do you have questions of Ms. Iannuzzi?

COMMISSIONER ENGLER: I do. Thank you.

EXAMINATION

BY COMMISSIONER ENGLER:

Q. Good afternoon, Ms. Iannuzzi.

You can hear me?

A. Yes. Good afternoon.

Q. A couple of quick things.

I am going to refer first -- it's your Exhibit E2 that has to do with your hypothetical time line.

A. Sure.

Q. All right. And in that time line, again you stated that, you know, from Hour 3 to Hour 7, basically that was from -- from the 3 to 7 hours was -- the main emphasis, or main issue, was you just can't shut things down right away. It's more of a production operations or operating conditions issue.

Is that correct?

A. Yes, that's correct. And it really

depends on the scenario. Some fields can be shut in quicker, some can be -- some can take longer to shut in.

So -- but it's really what time does it take to shut in the field?

Q. And do you know -- again -- and you can say this is beyond your scope.

Do you have ideas from the operations people what would -- what could constitute something that would be fairly short and quick, and what would take a long time to be able to do?

A. So I spoke to our field coordinator about this, when this rule was proposed.

And I was, like, what time line do you think is reasonable?

And for our newer wells, those we are able to shut in more quickly. But some of our older wells take longer.

Other factors include location. So there's just a lot of factors at play, like I've mentioned.

Q. Yes. Well -- okay. I don't want to go past that response.

Another question, I'm going to go to your ignition systems. That's your Exhibit E5.

A. Uh-huh.

Q. And one of the things you mentioned was, you have three -- you have different separate technologies.

And one of the issues you're mentioning, or NMOGA is trying to get a much longer time line.

Do you have any idea -- have you talked to vendors to see how many -- how much technology, how many of these -- how much of this equipment they do have in stock, or how long it would take to be able to make or create all of this?

A. No.

Q. Do you have -- again, you have to have installers, I believe you said, to install these technologies.

Do you have an idea, having talked to them, about how many -- how much they can do and how fast they can do it?

A. No, I have not. However, I did participate -- a couple of years ago we were working on doing some flare replacements. Our flares had gotten old and we needed to replace them. So -- so my experience with that was it took us several months.

And I don't even know about the

engineering that goes into it beforehand, because I just got involved because of the air permitting issue. So I am sorry, I'm not as familiar with that area.

Q. Do you know -- you're in the Midland Permian Basin now, correct?

A. Correct.

Q. Do you know how many flare stacks would have to be retrofitted, in this case, on the New Mexico side of the Permian Basin?

A. So I can't speak for everyone. I can only speak for Chevron. And I think we have between 10 and 15 flares that we need to retrofit.

But every operator is different, so I don't have a good number for you on that.

Q. I appreciate that. Thank you.

COMMISSIONER ENGLER: I am finished.

HEARING OFFICER ORTH: Thank you.

Commissioner Kessler, do you have questions of Ms. Iannuzzi?

COMMISSIONER KESSLER: I do.

EXAMINATION

BY COMMISSIONER KESSLER:

Q. Did you say that you were involved with retrofitting in Colorado, or no?

A. I have a basic awareness. I have one member on my team who has received air emissions in Colorado.

Q. Okay. You testified earlier that there were concerns related to composition for equipping retrofits, and put together a time that you're requesting -- that NMOGA is requesting for ramp-up of retrofitting.

Do you have any examples of where this has occurred prior, or is this just a kind of general concern?

A. It's a general concern, just based on NMOGA's past experience with dealing with these types of things.

We were thinking that 24 months is more reasonable, just based on our experience of getting the money. You would be surprised how long that takes, the engineering behind it.

So it wasn't just the manufacturers, but it was just kind of looking at the whole process. And we were thinking we can definitely get it done within 24 months.

Q. Okay. So I'm just trying to determine -- I understand that you outlined little different components of that time line. And I'm just trying

to figure out, particularly with respect to competition for resources, whether or not there are any prior examples that you can give the commission, or if it's just, as you say, just a sort of general concern?

A. Sorry, I don't have any examples.

COMMISSIONER KESSLER: Okay. Thank you.

HEARING OFFICER ORTH: Thank you, Commissioner Kessler.

Madam Chair, do you have any questions?

CHAIRWOMAN SANDOVAL: I do, of course.

EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. I forgot to ask these of the last witness. Do you support this rule?

A. So I can only speak for the parts of the rules that were included in my testimony. So they are namely 27.7G, which is the emergency definition; 27.8B2, which is talking about drilling; 27.8E3 and E3B, which we're talking about the continuous combustion and the timing for retrofitting; and E4, which was the spudding versus construction date question.

So I do support NMOCD's proposed rules, as shown in Exhibit 2A for Part 28.7, Part 27.8B2, and

Part 27.8E4.

But I did not support NMOCD's proposed rule as shown in Exhibit A2A for Part 27.7G, Part 27.8 E3, and E3B.

But if those technical changes, as proposed by NMOGA are incorporated -- and I think with a little bit of tweaking, we can get there.

Q. Okay. Do you believe that this was, from your experience with regulatory processes, a collaborative process?

A. So my role in all of this was to provide technical support. And so I didn't do any of the collaboration between stakeholders, so I can't speak to that.

Q. Okay. So you talked about how some of -- you know, during some emergency situations, instead of shutting in, you may want to switch to another gathering system, et cetera.

What does it physically look like on site? Like what are you physically required to do, if anything?

A. So I can't really speak to that because I'm not an operations expert.

But my understanding is that it does require some hands on work on site.

Q. Okay. I think you used the term "all," when you referred to it being, you know, sort of all-encompassing, and how you could respond to some in four hours, but you couldn't respond to all in four hours.

Could you respond to all in eight hours?

A. No.

Q. Do you have a percentage estimate of what you could respond to?

A. So I did a quick look, when you were talking about data last week, at Chevron's data. That's all I have.

And of Chevron's 243 emission events in 2020, four were related due to third-party takeaway issues. And of those four, one took longer than eight hours and the other three took less than eight hours.

Q. So we're really talking about potentially a very small number of events that could not be managed in eight hours?

A. So -- for Chevron.

Q. At least for Chevron. Correct?

A. (No verbal response.)

Q. Let's say that, you know, maybe the NMOGA proposition -- proposal of eight hours were to go

forward. How do you think -- or do you think that there could be operators who would take advantage of that?

And what I mean by that is people who would choose to wait it out, see if, you know, maybe the situation might change, until 7 hours and 59 minutes.

Or is there -- is there an opportunity for people to do that?

A. So my entire career has been with Chevron, so I hate to speculate what other operators would do.

Q. Do you think there's potential for that, with that large of a time window?

A. To be honest, if you look at the time line, eight hours is reasonable because of the drive time, because of the actual time that it takes to get on site. Also, eight is a nice round number.

We had extensive discussions within the NMOGA group that John Smitherman mentioned. I'm one of the 79.

We really talked about what -- and what would be reasonable. And we feel that the eight is not excessive because, you know, we see our outlets -- well, maybe 24 hours. No. 24 hours

would be excessive and could potentially lead to what you're talking about.

But eight hours is reasonable.

Q. Okay. That's helpful. Thank you.

Okay. In Exhibit 2A and 27.8 -- I think it is E3.

So you talked about -- so we talked about the complete and continuous, and what your concerns are on that.

The original language there was "maximum efficiency." And I think you said, in your mind, that equated to 100 percent.

Would -- I think more kindly, when something is called -- termed "maximum efficiency," isn't it more common to state the maximum efficiency of the technology and not 100 percent, or whatever that may be?

A. I don't know the answer to that. But it was my interpretation that maximum would mean 100 percent of all of NMOGA's interpretation.

Perhaps we could add language to clarify. I -- I don't know.

Q. Well, if there's confusion amongst several people, then -- I guess if there's confusion among several people, would you take that to mean there

may need to be some clarity?

A. Yes.

Q. Okay. Do you have any information regarding the actual costs that are associated with any of these three different systems? Or -- I think the three systems were auto ignite, continuous pilot, or technology that does something else. So two plus, or something like that.

Do you have any costs associated with retrofitting, and how much is it for each type?

A. I don't have any cost information. My focus is on air emissions and then figuring out what we can get for the air permits and stuff like that.

Q. And is there anyone who would have cost information?

THE WITNESS: Mr. Rankin, can you help me out?

MR. RANKIN: Madam Chair, I don't know. I think that's something that we can look at. I don't think, in the time frame that you've identified, cost is an issue. So I think there may be someone that can look at that.

I'm sorry I don't have an answer for you right now.

CHAIRWOMAN SANDOVAL: Okay.

Q. (By Chairwoman Sandoval) I mean, wouldn't the cost make a difference in terms of the -- you're talking in an air time line, right, that you have to allocate capital resources.

So wouldn't that cost make a difference on what the time frame is for that capital allocation?

A. No. Any capital allocation has to follow the same process, whether it's a million dollars or whether it's $10,000, at least for Chevron.

We have a process where you have budgeting requests for the following year. That usually happens in, like, early April. And then managers get together and they talk about it. And usually the budget for the following year is figured out by November of the current year.

So this -- the amount does not actually impact the time line.

Q. But don't you think that it would be a much easier ask if -- so for example, you said Chevron has 10 to 13 retrofits. If you're talking about $50,000 as opposed to a million, wouldn't that change the capital request, though, and potentially change the availability of funds?

A. I can't really speak to that. Again, my role at Chevron is to get the regulation and make

sure that we're in compliance with it.

Q. All right. Can you speak to the stripper well exemption in here of having to retrofit unless a continued -- or I'm sorry -- unless replaced?

Are you able to speak to that and the validity of that?

And Climate Advocates have a different proposal.

Is -- is this appropriate, that what's in there now versus what the other parties are proposing?

A. So NMOCD and NMOGA are aligned with the stripper well retrofit, which is if you end up replacing the flare, which does happen. I was involved in a project early -- a couple of years on that. Then we would replace the ignition system.

And so NMOGA supports NMOCD's proposal that as you replace flares at low-volume wells, you will update the ignition system.

Q. Okay. And so I think what Mr. Thompson said earlier is, you know, stripper wells are sort of on that marginal economic viability basis.

I can guess that that is why -- I believe maybe the OCD testified to this -- but that is why they gave some assumptions to save costs.

But is there a way you can think of to accurately -- or adequately, really, evaluate if this proposal of the division or NMOGA's is adequate without that cost information?

A. I don't know what you're asking.

Can you rephrase?

Q. Okay. So the division and NMOGA are saying on one side, stripper wells should get this exemption based on -- they shouldn't have to spend this extra capital, right? They're on the economic margin.

Climate Advocates and EDF are over here going, No, no. No exemption. They need to retrofit. They may need a little bit longer in time frame than the regular well.

I'm asking: How do I make a decision or evaluate which -- which party is presenting the best information, if I don't have costs yet?

So that's my question. How do I adequately evaluate these proposals if I don't have cost data to know, does it cost $2,000 to retrofit it or does it cost $20,000 per well or $200,000?

That's the question I'm asking. Does that make sense?

A. Yes, that makes sense.

It all goes back to what's the justification for why do stripper wells or low-volume wells not need to be replaced with the same frequency of others.

And I think it all goes back to what was the NMOCD's justification for making that change and having those two different states.

And I cannot speak for the decision as to why it wasn't a cost-free event, or an additional -- saying there's not actually that much flaring that occurs at those wells, because those wells are low-volume wells.

So I don't know the answer to that, whether it was cost driven, or was it actually from a waste perspective, that those flares are not as active as other flares.

So I guess that question would be better asked of someone else.

Q. Okay. But at the end of the day, you're confirming that we have no cost data.

A. Correct. I do not have any cost data.

Q. Okay. All right.

What -- in your, you know, experience with Chevron -- or I think you said you have only been with Chevron.

How often do flares get replaced? Or what's the scenario around flare replacement, and why does that happen?

A. So the reason why flares get replaced is they get old and break, just like anything else, so that can be a cause.

Another cause can be that we might be increasing production to a site, and so we no longer need a stripper well. It may actually be one of the normal producers. And so that's why we might not have adequate capacity.

So those are kind of the two general reasons as to why things get replaced, is general age or malfunction, as well as capacity constraints.

Q. Okay. What -- is there an average age range for, like, the life of a flare?

A. I don't know that. I'm sorry.

Q. Okay. Could you talk about, maybe, the scenarios around when it's more appropriate to use an auto igniter versus a continuous pilot?

A. Yes, I can speak generally. I'm not an engineer. I do have an engineering degree, but it's in environmental engineering.

Generally, first of all, we start looking at regulatory requirements. As I've mentioned, the

EPA requires, for the new storage performance standard 15.18, that they have continuous pilots, so we start off with that. So if it's required to have a continuous pilot, it gets a continuous pilot.

And then we look at -- is it an emergency flare or is it a process flare? Those are sort of the two different types of flares.

And in general, when it's an emergency flare, an auto igniter can be more appropriate, because they do not require pilot gas and is not expected to be lit all the time.

Whereas, if you have a process flare, that's going to be lit all the time, and it's going to have a steady flow type of gas, and that won't be a problem.

And then of course there's always alternative technology that lets us know whether or not the flare is lit. And that could be -- I don't know. There must be some technical reasons for wanting to do that, generally, but -- preferred to having auto igniters or continuous flares. That is my understanding.

Q. Okay. So basically it comes down to, first, what the regulation requires and to -- mostly if it's an emergency or a process flare. Like what

type -- what's the function of the flare, and that's what drives it, correct?

A. Yes, that's correct.

Q. Okay.

A. The other factors. There can be, you know, gas composition, that could be an issue. The heating value that can play into can gas actually burn?

There are a lot of things that go into flare design, and that's one thing that I've learned, and I definitely don't know it all.

But that's been my experience.

Q. Okay. I think you said that Chevron estimates that it has 10 to 15 retrofits?

A. Yes.

Q. Out of how many?

A. I do not know the number of flares that we've got in New Mexico.

Q. Is it like a hundred or a thousand or somewhere in between that, or is there a magnitude?

A. I know -- this is just generally. Don't hold me to this number -- it is -- between Texas and New Mexico and Colorado we have around 150 flares.

Q. Okay. Did NMOGA do any sort of analysis on if -- if the -- your regulation were to go

through as the division proposed, or as NMOGA proposed, what -- how many would need to be retrofitted?

A. Not to my knowledge. But I was not involved in every aspect of this rule making.

Q. Okay. So then you wouldn't be able to adequately know on E5, right?

(Discussion off the record.)

Q. (By Chairwoman Sandoval) Okay. So you said in E5, your Exhibit E5, in one of the timing issues and why you're justifying 24 months as opposed to the division's 18 months, was for manufacturers to propose emission systems.

So how do you know if it's going to get strained on the manufacturers to produce the emission systems if you don't know how many actually need to be retrofitted?

A. That is a great question, and I don't know.

Q. Okay. All right.

CHAIRWOMAN SANDOVAL: Well, I think that's all of my questions. Thank you for your time today.

THE WITNESS: Thank you.

HEARING OFFICER ORTH: Thank you, commissioners, Madam Chair.

Mr. Rankin, do you have any followup?

MR. RANKIN: I don't have any followup questions and ask that this witness be dismissed.

HEARING OFFICER ORTH: Thank you. So there's no reason not to excuse Ms. Iannuzzi.

Thank you very much for your testimony, Ms. Iannuzzi.

THE WITNESS: Thank you.

HEARING OFFICER ORTH: Mr. Rankin, your next witness I see is estimated at an hour. That's Mr. Reinermann.

Perhaps you could lead him through, say, 20, 25 minutes or so, and then we can take a break.

MR. RANKIN: Madam Hearing Officer, at this time Mr. Feldewert will be taking over examination of Mr. Reinermann, so I will leave it to him to identify an appropriate breaking point.

HEARING OFFICER ORTH: All right. Thank you.

Is that you, Mr. Reinermann, that I see on the screen?

THE WITNESS: Yes, it is, ma'am. Good afternoon.

HEARING OFFICER ORTH: I can hear you quite clearly.

(Witness sworn.)
HEARING OFFICER ORTH: Mr. Feldewert?
MR. FELDEWERT: Yes. Can you hear me okay?
HEARING OFFICER ORTH: Yes.

PAUL S. REINERMANN,

after having been first duly sworn under oath, was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Reinermann, would you please state your full name, identify with whom you are employed, and in what capacity?

A. My name is Paul S. Reinermann. I'm employed by Enterprise Products Partners, and I'm a field environmental manager.

Q. And have how long have you been with Enterprise as your employer?

A. I've been with Enterprise for eight and a half years.

Q. And as a result of your job responsibilities, are you familiar with the field operation of natural gas gathering lines and related equipment?

A. Yes, sir.

Q. If I turn to what's been marked as NMOGA Exhibit F1 through F5, does that accurately reflect your educational background and work experience?

A. Yes, sir, it does.

Q. It indicates, Mr. Reinermann, you have a degree in chemical engineering?

A. That is correct.

Q. And that you were employed by the EPA for seven years?

A. I was. I was employed in Atlanta, Georgia, in Region 4, in the enforcement group, and I was the chief of the compliance monitoring system at EPA headquarters.

Q. And that was for the seven-year period of time?

A. That is correct.

Q. Are you familiar with AVO inspections and frequencies imposed by state and federal agencies?

A. Yes, I am.

Q. Okay. And prior to joining Enterprise, after you left the EPA, what -- generally, what did your job responsibilities include?

A. Prior to joining the EPA?

Q. Or after you left the EPA and before you joined Enterprise.

A. Yes, sir. I worked for a company in Northern Virginia, Maryland, called US Generating Company. There, I was an environmental engineer for them. They were a power producing company.

Then I worked for a software company out of Austin, Texas, selling environmental software solutions.

And then I worked for Invista, out of Victoria, Texas, as a senior environmental engineer and a program leader.

Q. And have -- have you been involved in interpreting and commenting and ensuring compliance with regulations, state and federal?

A. I have, sir. I've had quite a bit of experience with new source performance standards, max standards, data regulations in Texas and New Mexico, predominantly -- almost exclusively recently, and also permits.

Q. Okay. Now, I want to focus on your experience with field operations for gathering systems. Okay, Mr. Reinermann?

A. Yes, sir.

Q. Would you turn to what's been marked as NMOGA Exhibit F6?

A. (Witness complies.)

Q. And does this reflect the first topic of your discussions?

A. Yes, sir, it does.

Q. And it involves the definition of emergency?

A. Correct.

Q. And I want to focus first on -- now, this is 27 -- I'm sorry -- Part 28.7B35?

A. Right.

Q. Where we see that NMOGA has proposed striking "including recurring equipment failure"?

A. That's correct.

Q. And there's a comparable provision in Part 27.

Right, Mr. Reinermann?

A. I believe so, yes, sir.

Q. Okay. Now, I want to focus on your actual experience. Okay?

A. Sure.

Q. Now when you see a regulation like this, and it says "recurring equipment failure," do you understand what that means?

A. Recurring, to me, means it occurs more than one time, which is a very tight standard to have to go with. I've heard others -- testimony

from OCD state that they are looking for a pattern. So a pattern is more than recurring. Recurring, to me, means more than once.

So that's why we believe that that language should be struck.

Q. Okay. Would you focus on your experience and provide the commission with experience that you have -- experiences that you have seen that would substantiate removing recurring equipment failure, so that it is not always considered to be operator negligence?

A. Yes, sir. There's a couple of examples I've included in my exhibits.

And the -- the first one I'll point to is the -- a compressor that could have a safety alarm be triggered on in the engine, that shuts down the engine.

The engine is a very complex piece of equipment. Some are older, some are newer.

The older ones will have just -- for lack of a better sake, a light that comes on that says "engine." That's it. The engine.

So the operator then is challenged to go try to find the reason why that engine shut down.

He'll go out and evaluate, and he might

come up with what he believes is the cause of it, and go to try to fix it.

If he does not -- if he -- he'll restart the engine, get it going again. Sometimes it might run for half an hour, sometimes an hour, sometimes a few hours, sometimes a couple of days. But then again, it could shut down.

So it might recur; that same engine alarm pops up again. And he'll go and try a different cure for that. And generally, eventually, gets it running back up and in good fashion.

For a newer engine, a lot of times we have a very specific alarm. It would say that you have a high cylinder temperature. So that person would go out there and replace the thermocouple that monitors that temperature. He puts it back into service.

And all of a sudden, after it's back online it, again, will trip off. And if that happens, what could occur is, then, that he might have to replace the line that goes between the thermocouple and the sensor, the computer that's actually controlling it, and replace that line.

I've seen this in this practice. I do quite a few semiannual monitoring reports for OCD -- sorry. Excuse me -- for NMED.

And I also do quite a number of semiannual deviation reports in the state of Texas. And you see this, that it might take three or four times troubleshooting to get the trouble right.

And each time that that engine shuts down it blows down. It blows down because it's a safety device. It's needed to be blown down. It needs to blow itself down, and that's for safety.

So that's one example I have with some engines there.

The other one is with regards to a process safety valve. This actually happened in the field in New Mexico. And the process safety valve failed, opened prematurely. And when it did so, we brought in a qualified technician to come and evaluate the PSV. It is a third party that provides quick process safety valves.

And the person determined that what needed to be done was the line needed to be cleared.

Then he went and tested the valve three successive times with nitrogen. That's his practice, to make sure that it relieves at the proper pressure.

He put it back in service.

Within an hour that valve popped again.

And this time the technician decided to take the PSV completely apart and put it back together again.

So it -- it popped twice. So that is a recurring failure.

However, we don't believe that that is necessarily a pattern. We actually believe that was indicative of good operation maintenance and engineering practices.

Q. And the concern here, Mr. Reinermann, is, as drafted, that would always be considered operator negligence?

A. That's correct. And that's not the case. Negligence is a very strong word.

Q. Okay. Now, I think you covered your Exhibits F7 and F8.

Let's go back to F6.

I want to move to the second topic. And that is, we see that there is a provision in there that if you have three or more emergencies experienced by the operator within a preceding 60 days, then the third emergency, no matter what happens, no matter what the cause, would not be authorized as a venting and flaring event.

Is that how you understand it?

A. Yes, sir. That's the way I understand it.

Q. And NMOGA has proposed to add the phrase "at one site," and then the phrase "for similar causes." Okay?

A. Yes, sir.

Q. I want to apply your experience and what you've seen.

And please explain to the commissioners why you believe "at one site" is an appropriate addition here.

A. Absolutely. I have had experience where you've had a power outage occur in a wide area, knocking out several compressor stations at the same time. When that occurs, all of them will vent.

So by the way this -- by the way I would read this rule is that I would generally count three of those ventings. I could not account for more of them.

Quite a few times --

Q. Mr. Reinermann, I want to interrupt you.

Is that -- is it true it would be three, or would only the first two be used?

A. You would be correct. Just two out of those. Yes. Two would be excused. That's right.

Q. Okay. Go ahead. I'm sorry.

A. No -- no problem. Thank you.

So those types of emergencies do occur out there.

Weather related, some people have spoke to those. Lightning strikes also occur out there. It's not as simple as putting in a lightning rod to protect equipment from a direct lightning strike and shutting it down.

The lightning strike can affect much more than the equipment. A lot of times it will affect the electricity coming into the plant. And when that happens, it can shut down that plant and cause it to vent.

Can these things occur, you know, more than three times in a 60-day period? You bet. Absolutely, especially in the wintertime.

And also in the hot summer months there could be a lot of electricity issues in the hot summer months.

I've been involved with rolling brownouts occurring in situations in Texas, at least, where we have had to basically curtail operations. And that would affect emissions.

Q. Okay. Now, I want to focus on the second part of that phrase that NMOGA seeks to add, the phrase "for similar causes."

Why is that equally important, Mr. Reinermann?

A. It's important because at a facility, you can have emergencies arise for different causes during a period of time. And so it's very important to segregate them out.

I would almost say that -- you know that one phrase "for similar causes," is -- and you're only limiting it to two at the site for similar causes, it could be also rather tight.

However, we believe that the limitations there by the -- the people who worked with the NMOGA group, believe that that would be a right way to go about doing it.

We didn't see fit to change it to three or more, but we do believe it should be at one site for similar causes.

Q. Do you have any examples, for example -- have you seen any circumstances where you had more than three within 60 days because of incidences involving Fireyes?

A. Yes, sir. Yes. We have a -- I have a compressor station in Texas that -- a lot of compressor stations utilize Fireyes to detect whether or not there's a pending fire. And if it

does see an impending fire, or it believes that there is an impending fire, it will shut down the station and vent the station.

I have seen Fireyes where they have seen a welder's rod from a distance, turn it -- and have it go off.

And then also a flare from an adjacent facility go off and cause the Fireye to detect the possible presence of a flame and then cause the station to be vented down.

And I have seen that occur several times in the time frame. Now those type of emergencies, you know, a Fireye's designed to de-fire. False positives are fine, based upon the design.

There is a design document of a Fireye. It will say that false positives are possible.

False negatives, though, you don't want to have happen. False negatives means there's a fire and it doesn't see it. You don't want that to happen.

So you definitely want to have your Fireyes be a little bit on the sensitive side rather than on the insensitive side, for safety purposes.

Q. Mr. Reinermann, based on your experience, then, and what you've seen in the field, do three or

more emergencies experienced by an operator within a 60-day period indicate operator negligence or poor maintenance?

A. No, it would not.

Q. And does NMOGA's proposed language here effectuate the intent and the balance that we believe the division is trying to reach here?

A. Could you rephrase that, Michael? I didn't quite understand that.

Q. Sure. Does NMOGA's proposed language take away from the intent of the -- as you understand it -- of the division's reasons for addressing this type of clause?

MR. AMES: Assumes facts not in evidence. The witness has not testified what he believes the OCD's intent was.

HEARING OFFICER ORTH: All right. That is sustained.

Would you restate, Mr. Feldewert?

MR. FELDEWERT: I thought he said he understood it's because they were trying to seek a pattern.

HEARING OFFICER ORTH: To seek a --

MR. FELDEWERT: Pattern.

HEARING OFFICER ORTH: Oh, a pattern.

Would you please rephrase your question?

Q. (By Mr. Feldewert) So, Mr. Reinermann, in your opinion, does the phrase "at one site for similar causes," is that appropriate here?

A. Yes, sir.

Q. Okay. And based on your understanding of what the division is trying to accomplish here, would the addition of that phrase take away from that intent?

A. No, it would not. It -- it was very clear, when OCD testified that -- with regards to recuring equipment failure, they're looking for a pattern. And that same type of pattern would be looked at when you're looking at similar causes.

Q. Okay. Then I want to share my screen, if I may.

Do you see my screen, Mr. Reinermann?

A. Yes, I do, sir.

Q. This is NMOGA's -- I'm sorry -- the OCD's Exhibit 3E, which deals with Part 28.

A. Yes, sir.

Q. And if I go down to Subpart 28.8B -- it used to be 3, now it's 2, Subpart A.

You'll see that the division has included "scheduled" in front of repair.

You see that here?

A. Yes, sir.

Q. Would you start -- would you turn to NMOGA Exhibit 12, and explain why you believe, based on your experience, this change is appropriate in Part 28 as well as Part 27?

A. Sure. And that is what is by NMOGA, and it's clearly in the new OCD draft of the rule.

But both scheduled and unscheduled maintenance, regardless of how you go about doing it, is going to be -- it's going to have the necessity of blowing down the equipment for safety purposes.

Typically, the first step in any type of repair maintenance is to isolate the equipment. And then once you have it isolated, to blow that equipment down safely.

So if you -- regardless of it --

(Discussion off the record.)

A. Repair and maintenance. Whatever you do with repair and maintenance, regardless if it's scheduled or unscheduled, you're always going to be isolating the equipment, isolating the piece of pipe, and then blowing that down. So you always have to do that.

So the change in this rule, it allows both scheduled and unscheduled repair and maintenance to be blown down and have that volume not count against our capture efficiency.

Q. (By Mr. Feldewert) Can you explain, Mr. Reinermann, based on your experience, why you would have unscheduled maintenance?

A. Yes, sir. For example, an operator making his rounds, hears something going on with an engine, that I need to shut the engine down in order to get it running right. Something is not quite right with it.

He will then contact his supervisor, discuss the situation. If there's another engine available on site they might crank it up to take the flow of gas. If not, then they would, perhaps, have to notify upstream that -- that they're taking down that engine.

But then they would go ahead and take down that engine. The first thing they do when we take it down, they would shut it down. And when it would isolate, then it would blow down the piping that's in the site.

Q. Mr. Reinermann, based on your years of experience, is it appropriate to afford the same

ability to vent and flare, whether it's scheduled or unscheduled maintenance?

A. Yes, sir.

Q. Okay. All right.

Now, I want to take a look at a change proposed by Climate Advocates to this particular section. Okay?

A. Yes, sir.

Q. And I believe I have it up on the screen. And it relates to Part 28.8E3.

A. Okay.

Q. And you'll see, Mr. Reinermann, on the screen, that they propose to add a clause on repair and maintenance that says "only where the gas cannot be rerouted back into the pipeline outside of the depressurized zone or otherwise beneficially used."

Based on your experience, is that proposal reasonable and practicable?

A. It's not something that's currently done in practice at Enterprise Products.

Q. Okay.

A. Typically what we try to do, though, is we try to move as much gas out of a pipeline or out of a process as we can before we have to isolate it and then blow it down.

Q. Is this something that can be done by existing gathering lines? Are they configured to do this?

A. In my knowledge of looking at this situation, I have seen where it's done in transportation by certain companies, where they will set up and do this. Typically it's on much larger lines than what you see -- from my understanding, it's on large lines, like 30-inch, 36-inch lines, that you see in transportation, or bigger, not on ones that you see in gathering, such as 4-inch lines or 6-inch lines or 8-inch lines.

I've never done it in practice that way, but I have heard it done for large transportation lines.

Q. Okay. Okay.

I want to now take a look at what has been marked as NMOGA Exhibit F13. Okay?

A. Yes, sir.

Q. And this relates to Subpart 28.8B3. And I thought it was on here, but I guess I need to look at the division's changes on that, so hold on one second.

Okay. So I'm on the division's exhibit -- OCD's Exhibit 3A. Okay, Mr. Reinermann?

A. Yes, sir.
Q. And I'm on page 2.
A. Okay.
Q. And you'll see that the division has, with their modifications, added some additional operations to subpart -- what used to be B3 and is now B2?
A. Yes, sir.
Q. Okay. In your experience and opinion, are these additional operations appropriate here?
A. Absolutely. The first addition on Line C about dehydration units -- well, ambient treaters and dehydration units are, in my experience, pretty much go hand-in-hand.

Actually, first, you go through an ambient treater to remove H2S and carbon dioxide. And then -- then you go to the dehydration unit.

So they will both create a flash gas, and they will also have a seal associated with them. Because what you're trying to do is the chemical recovery of all of the ambient, or in the case of a dehydration unit, the triethylene glycol.

So that just makes sense, as far as that goes, and to not include those.

In fact, I'll point out that in some cases

carbon dioxide can be as high as 2, 3, or 4 percent or more in the incoming gas. And if that's the case, if you weren't allowed to discount that, then that natural gas -- you could not make 98 percent recovery on it, because you'd already be removing 3 or 4 percent carbon dioxide. So the addition of the ambient treater is a very important one to have in here, and we appreciate that.

Q. And do you have a further description of the ambient treaters on NMOGA Exhibit F14?

A. I do, yes, sir.

Q. Okay. Now focusing on this as a circumstance for the operators authorized to vent or flare, Exhibit F15, I believe, discusses the addition of the language "turbines."

Do you see that?

A. Yes, sir.

Q. Would you please explain why that is an appropriate add, as an authorized instance to vent or flare?

A. I believe Mr. Smitherman brought this up in his testimony.

The turbines drive compressors just like engines do. They're used in different circumstances. It depends upon what the need is in

the field, as far as if you're going to utilize a turbine or an engine out in the field. So it just makes sense to include turbines in the same line as compressor engines.

Q. And one of the things I want to touch on is the Subpart E, 28.8B2 Subpart E, dealing with thief hatches.

Do you see that, Mr. Reinermann?

A. I sure do, yes, sir.

Q. What is a thief hatch, and why is it appropriate to have here as an authorized venting and flaring event under the circumstances described in the division's language?

A. Right. The -- what we try to do with the -- well, my reading here in the division language, it says "but not including venting from a thief hatch that is not properly closed and maintained."

And wait a second. I'm sorry. I think I read from the wrong exhibit, I apologize.

Q. I think you're -- we're on Exhibit F15.

A. Right. Yes.

Q. Tell us what a thief hatch does and why this is appropriate.

A. Sure. What a thief hatch will do, if a

tank fills up with liquid, it has gas in that liquid, and it also is displacing the gas. So the gas has to go someplace. It will go out the thief hatch. It will overpressure it and it will go out the thief hatch and vent.

Then when the liquid level gets stable in there, the thief hatch will quit venting, and it will hold a slight pressure on it.

As you drop it down it acts as a vacuum breaker to prevent the tank from either collapsing in or expanding out. In either case, this is what you want. That's why you have a thief hatch.

Q. Okay. And in your opinion, that, likewise, is an appropriate authorized venting and flaring event?

A. Yes, it is.

Q. Okay. Now, I want to switch gears here and go to NMOGA's proposed -- one of NMOGA's proposed changes here. Okay?

A. Yes, sir.

Q. Now, I am on NMOGA Exhibit B.

A. Okay.

Q. And I'm under the same section, Part 28.83 -- B3?

A. Yes, sir.

Q. It lists -- and I see a proposed addition by NMOGA for "fugitive emission components such as valves, flanges, and connectors." Okay?

A. Yes, sir.

Q. Now there was some discussion about this yesterday, and I want you to -- perhaps using your Exhibits F15 or F16 and F17, to explain what you're talking about here and why this is an appropriate addition to this section that authorizes venting and flaring as the division has defined it.

A. Okay. These emission components, they've been around in our industry starting back to KKK requirements under 40 CFR part 60. And they defined a leak rate for different components.

Originally, leak ratings were 10,000 parts per million for flanges. And now typically, today, you see 500 -- or for flanges and valves. Now they see 500 parts per million as a leak detection rate.

So they will vent emissions. That -- and that's the key. They will vent emissions. They will release them.

We have to permit these with NMED. They are permitted emissions.

And the two examples that I have here note these emissions for this -- a compressor site,

compressor station, of 3.6.

And then on the next page is another site where F-001 are also the fugitive components. This is a very large facility that has emissions of 35.9 tons per year permitted through the state of New Mexico, through NMED.

And so those -- when you permit in the state of New Mexico, you're not allowed to reflect any type of control efficiencies for AVOs or for doing your leak detection reporting. You just use the flatout flares. You don't actually report the actual emissions.

So that -- in Texas and other states, you're allowed to make an assumption. The numbers are much less with regards to emission factors and control factors.

An AVO would give you a 30 percent control factor, for example, in Texas; whereas, traditional method, one monitoring would give you 97 percent credit for emission reductions when you go to permit. So that would be why we want those emissions permitted.

I would also state that I would agree that a valve that is leaking above its leak rate is malfunctioning. That valve needs to be repaired.

It will be repaired, and we do so.

So in this program where we have AVOs, when we find a leak out there, when we hear a leak, when we see a leak, when we smell a leak, we will go to fix that leak such as that we no longer either see, smell, or hear it anymore.

So in that case, when we hear it, then I believe that there could be some techniques that we could use to say, This is how much my malfunctioning component has emissions. But in that case it would be a malfunction.

So the language that we have proposed here, where it talks about fugitive emissions, is reflective of normal operating fugitive emissions. The fact that you would have permitted, not the ones that go above the regulatory limits that NMED or EPA has.

Q. Okay. And these emissions, can they be captured and sent to a sales line?

A. No, sir.

Q. All right. There's been a lot of discussion about commissioning of pipeline equipment facilities.

Have you heard that, Mr. Reinermann?

A. Yes, sir.

Q. I don't want to belabor it. But based on your experience, is that an appropriate addition here of an authorized venting and flaring activity?

A. Yes, sir, it absolutely is.

Q. Okay. Then I want to move here to page 6 of NMOGA's Exhibit B. And I also believe it's reproduced on your Exhibit F19.

Is that correct?

A. Yes, sir.

Q. Okay. All right.

I want you to discuss -- because this relates to gathering system operators. Okay?

Would you please apply your expertise and explain, A, what -- what you're seeking to accomplish here, and why that's appropriate?

A. Absolutely. You know, I think one of the things -- I want to step back real quick and say basic understanding of midstream of our industry is to get the gas from the well to the end customers, to move that gas. We get paid for moving the gas. We don't get paid for losing the gas, basically.

So ideally, we want to capture as much gas as we humanly can and as physically possible as we can, so we -- we attempt to do that.

We have in place many of the plans that

are listed here, that are identified here.

However, we don't believe that it would be the wherewithal of OCD to review all of these plans that they asked for to be brought in.

What we believe, instead, is that when we get through the first six months' exercise of gathering data, and we determine that we have issues, as we go through that to achieve that 98 percent capture efficiency, which I believe from my company, we should be able to do on the first pass.

I don't think that there's any need for us to submit in all of our operating plans, all of our procedures. They're managed by different parts of the company. You have -- you have a pipeline integrity group, you have a corrosion group, you have a commodity protection group, you have our maintenance group that works on the engines and things like that. We should have these plans throughout the organization.

The important thing is that when you see you are not making your requirements, to do something about it. I guarantee you, when we start gathering data, come July 1st for this rule, we will be looking at it weekly, monthly, quarterly, to see

where we're at and where we're not at with it and make adjustments to our system.

I'll point out that with regards to our maintenance plans, if we find an issue with a source that something is a pattern -- we've heard the use of the word "pattern" before -- there's a pattern that comes up, we might well adjust our -- our maintenance program to do something a little bit more frequently to prevent that pattern from occurring.

I'm not talking about when we would want to have to adjust our plans or submit revisions to the plan -- it's not real clear on this -- that we would ever have to do it, or it's just a one-time submittal, but it is quite a bit of work.

I believe that the idea of a mitigation plan to mitigate the cause of not achieving 98 percent capture efficiency is a real key to having people focus on the cause. And by focusing on the cause, you can have a solution to achieve it. That's what I believe.

Q. Okay. Let me ask you a couple of things, Mr. Reinermann.

First off, when you look at items such as cathodic protection, corrosion control, liquids

management, and integrity management, you mentioned you have various groups within the company.

I think those individual groups address those individual items?

A. That's correct.

Q. And are they working, in doing that, with meeting the obligations of other state and federal agencies?

A. At -- sometimes they are, yes, sir.

Q. Okay. And if I turn to what's been marked as NMOGA Exhibit 20, does this summarize the approach that you have suggested, that you submit a mitigation plan, if there -- if there's an operator that is -- after the first six months that this rule is in effect -- is not able to meet its gas capture quotas?

A. That's correct. That is what the feeling is here.

I want to say, when I used to do enforcement of EPA rules, there's a regulation called 40 CFR 64.11B that, basically, if you have excess emissions, that the administrator can make a finding that you do not properly operate and maintain your facility. And enforcing those rules I would routinely say, you know, your -- you -- your

percent of time over the limit was more than your competitor. I want to know what your maintenance procedures are for the activity that caused this.

And I would get that maintenance procedure in and review it and address it with them.

There -- from time to time, some of the maintenance procedures needed to be adjusted, and the companies did not really look at it.

So to me, that should be the focus, if the capture efficiency requirements aren't being met, if you're not doing your catch-up like you're supposed to, OCD should be asking proactively, Where are you at with this coming in to us, and what are you going to do to get into compliance?

So that's really where we want to be at with it.

Q. And does that provide operators -- gathering operators the flexibility they need to then focus on the issues of concern?

A. Yes, it absolutely does. And you know, the -- besides focusing on the issues of concern for not hitting capture efficiency requirements, the -- the other thing about a mitigation plan is that it is really akin to when you have an excess emission occur out there.

You are asked very directly, What is -- what is the cause? What is the corrective action? And in some cases, What is the preventative action? All three.

And that would align with what this mitigation plan is. You identify the cause; therefore, you must initiate a corrective action and a preventative action plan.

Q. In your opinion, would NMOGA's approach here incentivize gathering operators to meet their gas capture requirements?

A. It would. It would incentivize them to make sure they really pay attention to it. And when they are looking like they're falling off, to fix it quickly.

Q. And avoid having to put together a mitigation plan?

A. That's correct. At least one that, formally, they would have to submit.

Q. All right. Now I want to briefly, now, turn to your experience with AVO inspections. Okay?

A. Yes, sir.

Q. And I believe your Exhibit F21 identifies NMOGA's proposed modifications for gathering for operator frequency, correct?

A. Yes, sir, it does.

Q. And we have some similar proposed frequency changes for upstream operators?

A. Yes, sir.

Q. You mentioned that you were familiar with AVO inspections when you were with the EPA?

A. I'm more familiar with AVO inspections since I've been with Enterprise.

Q. Okay. All right.

And what do you observe about EPA's AVO inspection requirements, and what experiences EPA have seen from them?

A. I like to sort of broaden AVO. AVO is a fugitive emissions monitoring program, a type of it.

There's other types that are actually alluded to in the draft-proposed NMED rules, which are not part of this.

You have AVO, audio, visual, olfactory, looking for leaks. Basically looking, smelling, and hearing for leaks.

And then you have the traditional way, what's called leak detection and repair program, utilizing method 21, which is a handheld analyzer, that you go and you go through the plant systematically looking at each and every valve and

connector to determine if it has a leak.

The other type -- there's a newer type that came out in Quad-O and Quad-OA, which is utilizing OGI, which is a type of optical gas -- sorry. It's an optical gas instrument, so an optical gas instrument that sees leaks. People refer to them as flare cameras, which is an infrared type technology.

So EPA, under KKK, under Quad-O, Quad-OA, says that on the first month you go out to a brand-new site you will look for leaks.

You will go again for a second month and look for leaks.

Thereafter, if your leak rate is less than 2 percent, you go on a quarterly basis.

All of the sites that I have that have that type of scenario, month, month, quarterly, stay on a quarterly basis because their leaks always stay nice and low, well below the 2 percent leaker rate that's prescribed.

So the same thing --

Q. Hold on. Let me stop you right there.

A. Okay.

Q. So first off, you've testified that EPA currently has a monthly requirement.

Is that right?

A. It starts out monthly for -- this would be for a natural gas processing plant.

If you go to Subpart Quad-OA, you will find that it is on a semiannual basis. It had been on a quarterly basis. But if you're doing OGI monitoring, it's now on a semiannual basis.

Q. Okay. And when they -- when you had facilities move from monthly to quarterly, you testified, based on your experience, you had never seen them go back, have to go back to monthly?

A. That's correct. And that's because the first time through a plant you will find those leaks that first month. But then by the time you get to the second month, there will be -- all your bad actors will be gone.

And you'll have a few here and there that occur due to vibration and other things that would be considered to be a leaker, which is varied from 10,000 parts per million. Which, when I talked before, I mentioned under this rule it sounds like it would be a malfunction.

Q. Okay. Now, what does EPA recommend in terms of EPA -- or annual inspection frequencies, Mr. Reinermann?

A. EPA really only has AVO in a couple of rules that affect pumps. And in that basis, it is weekly for pumps. You are looking for a leak from a pump. That is a single piece of equipment.

I can -- in the current oil and gas -- oil and gas permit from NMED, it calls for monthly for sour gas facilities like these.

So being a sour gas, that's much -- sour gas is much more deadly than methane -- excuse me -- it just is, if you get high concentrations of it.

In the rule it says, basically, to inspect it on a monthly basis for the AVO, in the current oil and gas GTP permit.

So in that case, that -- this monthly recommendation we have here would be consistent with that.

I will say, though, that the current draft-proposed NMED rule speaks verbatim, almost, of a rule that we see here in OCD, which is to do weekly AVO inspections.

Q. Okay. I want to get to that in a minute.

Before we get to that, I want to take a look at NMOGA Exhibit F22.

A. Okay.

Q. And does this express what EPA's approach

is with respect to AVO inspections?

A. The compressor station, subject to 40 CFR Part 60 Subpart Quad-OA are subject to correlated leak detection monitoring. That is correct. That's done by an OGI monitoring system.

Q. Okay. Now, poor Paul Baca is trying to take this down, so we --

A. I'm sorry. I'm sorry, Mr. Baca.

Compression stations that are subject to 40 CFR part 60 Subpart Quad-OA are subject to leak detection monitoring quarterly, leak detection monitoring using a -- OGI monitoring.

Q. Okay. Now I want to ask you, based on your experience, does the monthly AVO inspection obligation that NMOGA suggests is appropriate here, is that consistent with what EPA requires?

A. What -- weekly is definitely more than the quarterly leak detection, much more frequently.

The -- the -- I've heard it said a couple of times by OCD that it's just a matter of checking a box that you either saw a leak, you're looking for a leak, or you smell a leak. It's just as simple as that.

If the rule says visually inspect for leaks, I think we'd be fine with this rule. And it

says listening for pressure and liquid leaks. It says smelling for unusual and strong odors.

But it says visually inspecting externally for cracks and holes.

Does that mean they have to be leaking or not?

Loose connections. Loose connections by themselves, whether or not they're leaking or not, we've got to look for them.

Then leaks. That's leaks.

Broken and missing caps.

Broken, damaged seals and gaskets.

Broken, missing, and open hatches and broken, missing, and open hatch access cover devices, whether or not they're leaking or not.

Visually looking at this.

It's much more than just going out and looking for a leak. Again, if it says visually inspecting for leaks, we'll get a whole lot simpler. That's an easier checkmark of a box and, yeah, we go fix the thing.

And it has been asked several times about who comes on site. Yeah, they come on site quite a bit, operators do. Once a week, typically, for compressor stations, without a doubt.

And do they look for leaks? Darn tootin' they do.

Do they fix them? Yes, they do, when they get out of there.

But they don't necessarily go through the entire site and look for the -- what I'll refer to as a list of equipment and cracks and holes and loose connections and broken and missing caps, et cetera.

They don't necessarily do all of that, but they do look for leaks. There's a difference there, a big difference.

Q. And, Mr. Reinermann, I know you're passionate about this.

Were you reading from the rule itself when you referenced all the things that are -- purportedly that are required by this rule?

A. Yes, sir. It's OCD Exhibit 3A. It's under 19.15.28.8C4A1.

Q. Okay. All right.

Now in your opinion, okay, will the weekly AVO inspections currently suggested by the division's rules substantially reduce surface waste, when you compare that to monthly or quarterly inspections?

A. No, I -- I don't believe so. Because the -- the -- typically, like I said before, you find leaks, you fix the leaks, the bad actors. You'll go back and find very few the next time you go out there.

So if you're going to initiate the program from the beginning, I would expect that that first time out, that first month, you might find more leaks than you otherwise would.

However, we have to operate safe facilities, reliable facilities. Part of being a safe and reliable facility is to make sure that we don't have leaks going out there. We fix our leaks.

So operators do do these AVO's already. I don't think we're going to see any difference in what we have now versus later. I don't think that volume of gas will change and go down at all for our industry.

Q. Okay. Now, I want to share the screen again. I want to look at what's been marked as NMOGA Exhibit 21.

Do you see that in front of you, Mr. Reinermann?

A. No, sir. I believe you need to share.

Q. You're right. I do. Thank you.

Can you see it now?

A. Yes, sir.

Q. Okay. Now, I want to focus on this last sentence that NMOGA has proposed to add here.

A. Right.

Q. Now, Mr. Reinermann, I believe it was previously discussed that this could either be a second sentence or an introductory clause.

But this proposed sentence would exclude AVO requirements if they're required by other agencies listed here, correct?

A. Yes, sir.

Q. Okay. We've heard some discussion that the NMED has proposed -- they have not adopted -- that they have apparently proposed weekly AVO inspections. Okay?

A. That's -- that is correct.

Q. Now if this sentence was added to the AVO frequency requirement, would that address the circumstance that would arise once the NMED actually decided the frequency that would be appropriate for what they're attempting to do?

A. Yes, it would. You know, I've heard that the idea is not to be overly burdensome with these rules; that OCD and NMED worked together, they

collaborated together.

This section of the rule was brought to AVOs, at least the part that's in OCD, is completely redundant for our industry. And what's in the proposed NMED rules at 20.2.50.16.C, completely redundant of it.

And so if we're going to be subject to the NMED rules that are exactly the same as these rules, then when we shouldn't have two masters. Just one -- just the one master. That would be NMED, in that case.

Q. And, Mr. Reinermann, at this point, we don't know what the NMED is going to adopt, correct?

MR. AMES: Objection, leading.

Q. (By Mr. Feldewert) Mr. Reinermann, do we know at this point what the NMED is going to adopt?

A. No, sir, we don't.

Q. Okay. And this provision would address the circumstance -- would address whatever NMED decides to do?

MR. AMES: Objection, leading.

HEARING OFFICER ORTH: Mr. Feldewert, please watch that and rephrase.

Q. (By Mr. Feldewert) Mr. Reinermann, what do you -- would the addition of this sentence assist

in addressing whatever the New Mexico Environment Department decides to do?

A. It would allow us to focus on one set of regulations instead of two, for accomplishing the same purpose.

Q. Okay. All right.

Now, I want to take a look at the division's Exhibit 3B -- or Exhibit 3A, I'm sorry.

And I want to go to Page 3.

Do you see that up in front of you?

A. Yes, sir.

Q. Okay. Do you see that the division has proposed some changes to 28.8C5?

A. Yes, sir.

Q. And they relate to aerial visual inspections?

A. That is correct.

Q. Do you agree with this language change, based on your experience with AVO inspections for gathering facilities?

A. This is -- you don't really -- or at least I don't really think of AVOs for pipelines as much, which this is what this is about. I think of them as just doing visual inspections for leaks, basically.

But yes, that reflects what is done with regards to pipelines. And for -- that's for a number of our systems.

Q. Okay. And you'll see that it says to perform annual instrument monitoring of the entire length of the gathering pipeline.

Is that appropriate, in your opinion?

A. I would recommend striking the word "instrument" on that, just say annual monitoring. Because a gathering pipeline using an AVO technique along the technology of aerial visual inspection does not necessarily use an instrument.

There are some times when a flare camera or an OGI system is actually used to take a look at the line that is being flown over.

So it's not always done that way, though. A lot of times it's just a visual inspection.

So "instrument," to me, could be struck.

Q. Okay. And as we go halfway through, the division has added some language that would require the operator to retain records for at least five years.

Do you see that?

A. Yes, sir.

Q. Do you think that's an appropriate balance

of the burdens?

A. I do. It's -- typically, when we get requests from agencies for past records, very seldom do they go back two years, three years. They're usually more on top of it than that. So having five years gives them about a two-year backup in case they want to go back further and take a look.

Q. Okay. And then you see that they -- that the division has made a change to remove the names of personnel from the public records.

Do you see that?

A. Yes, sir.

Q. Do you think that is appropriate, and if so, why?

A. I think it's appropriate. The important part is that that person is qualified, and that he's -- he's documented as qualified in records that are kept, not necessarily in a report that's issued.

Q. And the way the division drafted it, would it require the name of that person to be in the records?

A. No. The person's name would not have to be in that record.

But I find that, typically, people always sign their work.

Q. Okay. And we'll go ahead and do -- we would avoid the name of the person in the public record, right?

A. That is correct.

Q. Now, I want to move to NMOGA's Exhibit F25.

Okay, Mr. Reinermann?

A. Yes, sir.

Q. And I believe I'm getting it up on the screen, here.

This is a change to Subsection 28.9C.

A. Right.

Q. All right. There is -- do you understand how this provision works under Subparagraphs A and B?

A. Under A and B? I -- yeah. By reading it, I do. I don't know who in our company will provide a GIS visually formatted as-built map, but I understand what that is.

We have something like that in house, that we can go and look at our lines with and see where they're at, with a lot of the information that's indicated there.

I don't know if we necessarily have all of the small lines and connections, but I know we have

the major ones.

Q. Okay. So under this Provision A, Subpart A and B, what is a company going to be required to provide?

A. I imagine -- this would be just as I would have to imagine it. We would submit in a -- either an electronic file via e-mail, upload it to some type of HTP site, probably, that OCD would then download and put into a system, a mapping system of some sort, that they would do it.

Then they would have GIS visually formatted data, and they would put it into their system.

They would probably want to give us specifications, to make sure that what we give them map -- map up to their mapping system.

And what I mean by that is that, you know, in -- you have degrees and pounds, and you also have other ways of expressing GPS data.

And in New Mexico we have sections and things like that, so we have a variety of different ways to do it.

So how do they want that data to come in to them? We make sure that we give it to them in that right type of order and fashion.

But then the idea would be to have some type of key that would allow them to identify the type of line it is and the service it's in.

Q. And so when I look at this provision, you're going to have to -- the operator is going to have to file a map of their system, right?

A. Correct.

Q. And then under -- what is to occur if they add any elements to their system?

A. If they're going to add elements to the system, then basically we have 90 days to provide them with an updated map.

Q. Okay. All right.

And under Subpart B, will that -- what will that information that you provide to the division include?

A. It's going to provide them the size of the pipeline, which is typically the inside diameter, and also the construction material of the pipe, which would be sealed, for Enterprise.

Q. Okay. So having known all of that, what's the problem with Subpart C, and why do you gathering operators suggest that this be removed?

A. So the way that I read this, as well as the NMOGA team members read this, is that where it

speaks to the part about the -- it says at the very last line, "release reported to the division since 19.15.28.9 NMAC became applicable to the pipeline or system."

We believe that that line there, release reported, we -- we report releases in that C 129 form. So that is -- that would be the ones greater than 50 MCF.

I did not read it, as Madam Chair had alluded to earlier, about that being ones that are less than 50 MCF. We haven't even contemplated that aspect, if that's going to be a requirement, because that's not real clear.

Because those are releases that we don't report on the C 129. We would report them in aggregate, I believe on a C 115B for the system, but not necessarily on a point-by-point basis for the other ones.

So the -- the thing is, is that when we submit in the -- I assume that the C 129 is going to be electronic, just like the current C 141 is.

And on that C 141 we provide the GPS locations in two different ways. And my thought would be that -- I believe it was Mr. Powell who spoke about the -- making the systems be better and

working smoother, is that when you put in that number and you're putting in the volume of gas released, that those two could be almost instantaneously pinpointed on a map.

Now as I'm working for Enterprise, I'm also part of the public. If there's releases going on out there throughout the year and they occur this month, when would they get on the map under this current rule? They wouldn't get on this map until May of 2022. Probably June 1, 2022. So that's almost 14 or 15 months later; whereas, coming in on the C 129 form, if I submit one today, it's the final form, that could be on tomorrow. There's no problem with that. They could keep their maps up to date easier than we could, and in a more time efficient manner.

Also, they could -- they could see patterns out there, potentially, also, and in a more time efficient manner than waiting until May 31 of the following year.

Q. And is that -- what you just discussed, Mr. Reinermann, is that reflected in NMOGA Exhibit F26?

A. Yes, it is.

Q. And is this something that the division is

currently doing anyway?

A. The division does have an OCD methane tracking dashboard. And frankly, looking at it, I couldn't figure out how it was actually populated with data. It may be where -- where the information comes from.

But I could see how that methane tracker dashboard that they have, you could use the C 129 data to populate it.

Q. Now, Ms. Sandoval is correct that the C 129 data would not include releases that are less than 50 MCF.

Correct, Mr. Reinermann?

A. That's correct.

Q. Okay. And that has been a threshold that the division has used for quite some time in their reporting.

Is that right?

A. That's correct.

Q. And how do you understand the -- what you -- how do you view a release of less than 50 MCF in terms of magnitude?

A. Okay. So in NMED, if it occurs at one of my compressor stations, I have to look at it as far as excess emissions goes.

I have certain caps at my site that allow me to have some emissions associated with unscheduled blowdowns, so I have to make sure I make compliance with that.

If I'm not, then what I would do is -- with NMED, I would submit an excess emission report.

So we -- we do have to be knowledgeable of them when they occur, if there's something that we can and do keep track of that could be put into a system.

However, we don't necessarily -- well, we don't report it on a form. We don't necessarily keep the GPS information for all of those type of things, especially on a pipeline, if it's a small one on a pipeline.

My experience is, is that most of our pipeline releases that we have, we have to do a C 141 form for because -- not so much for the leaks, but because of the blowdown we have to do to repair that leak is going to be greater than the 50. It's typically miles of -- a mile or two of pipeline might have to be blown down.

Q. And when you say a C 141, is that filed under existing division Rule 29?

A. Yes, sir.

Q. And does existing division Rule 29 require any filing for releases that are less than 50 MCF?

A. The only time you would do that is if you had a mostly liquid release that was greater than the threshold. In gas, it's slightly less. You might do it then.

But other than that, no, sir. It would not be the driving force for a report in that case.

Q. Okay. And with -- once the -- if the commission removes its Subpart C that we see in F21, the division will have received data of all releases in excess of 50 MCF, correct?

A. Correct.

MR. FELDEWERT: Madam Hearing Officer, I believe that that concludes my examination.

I pass the witness.

HEARING OFFICER ORTH: All right. Would you like to move your exhibits?

MR. FELDEWERT: Oh, thank you very much. Yes, I need to move the admission into evidence of NMOGA Exhibits F1 through F26.

HEARING OFFICER ORTH: All right. Let me pause for a moment in the event there are objections to NMOGA F1 through F26.

(Exhibits admitted, F1 - F26.)

HEARING OFFICER ORTH: F1 through F26 are admitted.

We do need a break. Let's take 15 minutes. We've been going more than two hours at this point.

When we return, Mr. Ames will have some questions for you, Mr. Reinermann.

THE WITNESS: Yes, ma'am. Thank you.

HEARING OFFICER ORTH: Let's come back at 3:05.

(A recess was taken from 2:49 p.m. to 3:07 p.m.)

HEARING OFFICER ORTH: Mr. Ames, you may continue.

MR. AMES: Thank you, Ms. Orth.

EXAMINATION

BY MR. AMES:

Q. Good afternoon, Mr. Reinermann.

A. Good afternoon, Mr. Ames.

Q. So I have a few questions for you this afternoon.

I heard Mr. Smitherman and you, as well, say that the GIS layer should not duplicate the C 129 reports.

Is that right?

A. It should not, that's correct. The way we read it, I would agree with that. Yes, sir.

Q. And so events less than 50 MCF don't get reported on a C 129?

A. Never have, no, sir.

Q. Don't say never will?

A. I did not.

Q. I know.

Under the OCD's rule, the GIS layer is going to show all emergencies, malfunctions, and releases regardless of size, right?

A. I don't know. I don't know if it could be interpreted that way, if you read the one part on it that talks about being for reported release events. And I would assume that a reported release event is one that's done on a C 129.

Q. But it also refers to emergencies and malfunctions, doesn't it?

A. It does. But again, I believe that it was -- the way that we looked at it as a group, is that it went back to the part about being reported to the division.

So an emergency malfunction and release reported to the division. So a C 129 for a release

that's less than 50 would not be reported to the division.

Q. So -- I'm sorry.

So you're reading it to a limitation to events larger than 50 MCF.

Is that right?

A. That is correct.

Q. Okay. So a prudent operator, a prudent midstream operator -- because Enterprise is a midstream operator, right?

A. Yes, sir.

Q. A prudent midstream operator that were to prepare a GIS, like requested in the OCD rule, would look at it, wouldn't it?

A. What do you mean by we would look at it, sir?

Q. Well, you prepare it, you put data in, you would take a look at it?

A. Yeah, absolutely. Yeah. Absolutely, yeah.

Q. Absolutely. You evaluate it for patterns?

A. You would -- you would -- you would look for leaks that occur on a recurring basis. And we have done that, as Enterprise. And when it came time to do it, we decided we have to shut down the

line and replace the portion of that line because it had too many leaks on it. That's correct.

Some of them were not large enough to be reported under the current C 141. Other ones were.

Q. A prudent operator, like Enterprise, would look at this GIS and consider whether it should investigate these patterns further?

A. We wouldn't have to have the GIS to do that. We would know it from our own internal documentation of the leaks when they occur out there.

Q. But if you had a GIS, you would look at it, and that would help you, wouldn't it?

A. Well, that is part of an evaluation, when you're looking at leaks that occur on pipelines, as to the area, because it's not necessarily the entire pipeline that might have to get replaced, but just a segment of it, not the entire thing.

So you would -- you would know that ahead of time, well before what it says here, May 31 of the year following.

If it started happening in January, February, March of this year, we would be on it faster than that, much faster than May 31, 2022.

Q. Right. You would want to keep the map up

to date?

A. No, not really. We would want to get that line fixed so it doesn't leak anymore. That's our first and foremost thing. We would be reporting the leaks to OCD. OCD may or may not take notice of it.

You would -- you would think that as they're getting in the data they would say, Hey, we see a pattern here. They should be able to see that pattern as quickly as we can, which we would.

But we don't have to have that on a GIS map to know that. We know that that line has an issue going on.

Q. Well, my question is: If you had that GIS layer, where you were mapping those emergencies, malfunctions, and releases of all different sizes, that's a helpful tool, isn't it?

A. No, not has helpful as you would think it might be. Because it is really looking at the line and looking at that system. It's looking at that specific engine that's having a problem out there in the field.

So it's -- it's -- a lot of times it's equipment line specific. The map would not be -- would not be something that we would do. It would just be a reporting tool in this case.

Q. Do you have, like, one person who does all your C 129s?

A. No, we don't have just one person that does our C 129s. We do not.

Q. How many people do you have?

A. We have -- well, none, because we don't do C 129s yet.

Q. Okay. Well --

A. Sorry.

Q. That's a fair point.

When you do start doing C 129s, who is going to do them?

A. I would imagine that my environmental staff would in my area. And then another manager, who manages the Farmington area, his staff would do his up there. So probably two or three.

Q. Two or three other people. And where are you right now, or where do you work from?

A. I work from Kenedy, Texas, sir.

Q. Okay. So someone in Farmington, someone in Kenedy.

Is there another location as well?

A. The person that works out of Midland, Texas. We have an opening in Carlsbad, though, if somebody is interested.

Q. Oh. So a lot of people with their hands in the pie on this one?

A. Not really, no. Operations is very focused on their lines, on their equipment. You have a supervisor who knows his equipment, who knows his lines. He knows when he's having issues. He doesn't have to have a map to go out and find it.

Q. Okay. Never goes on vacation, he's always there, he's watching everything all the time.

Is that what you're telling me?

A. There would always be somebody there who would back him up, a person who has the operational knowledge that that same person does.

The other thing is, also you're talking about something that's a pattern, okay? So you're looking at things that happen maybe a few times on the line in a system. And him being on vacation for a week or two, no, that -- that timing wouldn't matter that much.

Q. Patterns occur over longer periods of time, don't they?

A. They very much can, yes.

Q. And people move on over the course of time?

A. We do.

Q. So recordkeeping -- mapping, is a form of recordkeeping. It helps people -- it helps keep people in the loop, doesn't it?

A. I could see that that could help. We do have other systems in place that keeps track of those leaks. That can be very specific to -- to lines and locations and pieces of equipment.

Q. Okay. So I heard you say you want to capture as much gas as humanly possible.

A. That's how we make money.

Q. Do you recall saying that?

A. Yes, sir.

Q. Okay. And you also said that your company already has an operation plan?

A. We don't have just a single operations plan. Okay?

We have a myriad of plans out there that are similar to what is listed on this list here.

We have integrity programs.

We have engine maintenance programs, preventative maintenance programs.

We have people that do corrosion work with pigging of the lines periodically, to make sure that they stay clean as we get the liquids moved out of them.

So we have lots of different programs in place already to, basically, run our system, to ensure that we capture all the gas that we're contracted to capture, and to pass on to customers upstream -- further downstream, sorry.

Q. So you've got lots of plans, lots of programs, all in some way seeking to maintain the integrity of your system, prevent leaks, maximize the amount of gas that you move through your system. Is that right?

A. It takes a small army of people to do it right, that's correct. And they're all focused on doing it in a coordinated manner.

The person who is the operations supervisor knows what's planned for his lines and his activities. And so he's aware of when someone says, I need to do a pigging on your line. He knows when someone says, We have to do some cathodic protection work out there on your line to evaluate your cathodes and connections, to make sure they're right.

He knows when maintenance has to be done, so that two weeks prior he can notify someone upstream that we might be shutting down and could affect their operations. So we have a person that

coordinates all of that.

Q. So you have a coordinator for all the planning?

A. You could say that the supervisor is the coordinator for all the planning, yes, sir.

Q. Okay. And that coordinator understands how all the plans fit together?

A. I would say, yes, sir. Absolutely.

Q. And knows where, in this small army, to go to and figure something out that's going on?

A. Absolutely. Yes, sir.

Q. But not every operator does the same amount of planning that Enterprise does, do they?

A. I can't speak to that.

Q. You're not aware of the general practices in the field?

A. I've only worked for one midstream company. That's Enterprise Products, sir, so I cannot speak to others.

Q. But you did work for the EPA, right?

A. I did.

Q. And at the EPA, you did enforcement work?

A. I did. But we did not have oil and gas as a major company back then. In the southeast United States there aren't too many refineries and

petroleum plants and things like that down there. So this was back -- you know, back in the '80s. So we just -- really didn't have that much, as far as rules went, at that time.

Q. Sure. My focus here is not so much on oil and gas. It's just the fact that you did a lot of enforcement back then.

A. Yes, sir. That is correct.

Q. Brought a lot of actions against violators?

A. I participated in doing that, yes, sir.

Q. So would it be fair to say that not everyone is doing as good a job as Enterprise is?

A. Based upon my experience, if you, you know, look at -- look at ten companies and you go and meet with them and talk with all ten of those companies, they will absolutely tell you that they have safety, reliability, and environmental as forefronts for their companies, and that aim to be -- have safe operations, reliable operations, and environmentally good operations. All three would be in those ten companies. So ten out of ten, I believe, would say that.

Now how you go about accomplishing that, your -- your wherewithal, that could be different.

When we're talking about these plans -- if I could offer something to you, sir -- is that you have a requirement that you have these plans in place, not necessarily that you have to gather them all up and submit them. You have a checklist. Effectively, you've made a checklist here that you have to have these type of plans in place.

I could see that working well. And then basically, when you have problems meeting your capture efficiency requirements, tell us how you're going to fix things to get them right, the mitigation plan idea.

Q. Not every company has a small army like Enterprise, right, to manage its planning.

Is that right?

A. That -- that might well be true.

Q. And not every company out there, not every operator out there is like Enterprise, that has a supervisor who has the skills and ability to coordinate all of this small army and its planning activities.

Is that correct?

A. I -- I don't think so. I mean most companies that I've run into have plant managers, have people that are responsible for their

compressor stations, are responsible for their pipelines. They're either called supervisors, superintendents, or managers.

So they -- they do have a person that's in place that's responsible for the operation of that. And that would include making sure the maintenance is done properly and things like that.

So in most cases, plants that I'm aware of have supervisors in place.

Q. That's the position, right? But my question was: Do most companies have supervisors like yours, like your company, that is very adept at coordinating all plans to make sure that everything happens at the right time at the right place with the right people and the right equipment?

A. I don't know. I can't speak to that.

Q. So let's go back to the question that I asked that you didn't answer.

I asked you about your enforcement experience and whether you brought action against violators.

You said that you participated in many actions. So -- and then you told me that everybody out there says they do the same thing. They do a good job, they try and do the right thing. You

named four things in particular, the four pillars of good practice.

But you didn't answer my question, which is: Not all of them actually follow through, do they?

A. I think they -- I think they've tried to follow through. The actions that I've taken against power plants, against paper mills out there that I've ran into -- some very large names, which I won't mention -- will have operational procedures, maintenance procedures for specific pieces of equipment.

And when they have an issue with excess pollution going on, you ask them, What in your maintenance plans does it say how you reduce the excess emissions that occur? How do you reduce pollution?

And they'll say, Well, frankly, we don't -- the course I've had is most of them don't have something like that in line. They don't have a specific direction to the operator to do that.

And when we get that in place, they go do it.

So they are missing a line, basically, in their manual, and not the whole manual.

Q. So you're telling me that in the course of your practice with EPA, you've never come across a company or an actor who didn't cut corners?

Is that what you're telling me?

A. I didn't -- could you define "cutting corners"?

Q. Not doing what they're supposed to do, as required by the regulations that you were enforcing.

A. We never took any criminal actions at all, which is what you're alluding to, in my mind, at least, that they are trying to specifically escape the requirements. I'm not familiar with that. I didn't do any criminal activities.

Q. Well, in the civil context, you never were involved in enforcement actions where somebody didn't comply with the rules?

A. Oh, absolutely. I can think of a small boiler operator in a -- in North Carolina. In a wood-fired boiler that he built, put in place. And he put a baghouse on the back end of it, and it was under-designed for the application. But he was told that it was designed for the application.

And so he relied upon a reputable vendor, and that reputable vendor was wrong. And we took an enforcement action to get him to change it out.

Q. That's extraordinary. You mean the one example you just gave me, someone who really didn't -- wasn't, arguably, responsible for the violation itself. It sounds like you had smooth sailing in the enforcement area out there in North Carolina.

So let's talk about the operations plan and submitting it to OCD.

You testified, quote, you don't think it's important for OCD to review the plan.

Remember that?

A. I believe I said I don't think they have the wherewithal to review the plan.

Q. That's your opinion, right?

A. Uh-huh.

Q. Okay. So let's say an operator claims emergency and OCD says, Hey, that's -- it looks like recurring equipment failure to us. Let's see your plan.

If I understand your proposal correctly, your response is, We'll do a mitigation plan. I asked them to fix the problem. That's already occurred.

How is that supposed to help the operator foresee the problem before it happens?

A. Well, the thing is that with mechanical equipment, electrical-driven equipment, you can't possibly contemplate all the things that are going to occur out there that might cause you to have an upset that requires you to do maintenance on it. You might have to adjust that maintenance somewhere down the line to prevent that.

So in that regard, the plan could be looking at everything that is recommended by a manufacturer to be addressed, recommended by EPA and regulations, or under, like, Quad-Z, 40 CFR Part 63 Quad-Z requirements.

So you could -- you could address those, analyze, dot Is and Ts crossed. But you know what? You don't have enough.

So then what happens, you have -- my experience has been more, like, the excess emissions. Okay?

So this is sort of like the wolfs that happen out there. What we're trying -- what we're trying to do here is minimize waste, which is also the same thing. We're trying to minimize excess emissions. It's the same thing as what we're trying to do.

And so when we have excess emissions occur

out there, it is because our maintenance needs to get adjusted -- well, adjust the maintenance and get it right.

And that's what the idea of a mitigation plan is, is that, Hey, we've had this occur too many times out here. Let's get it fixed.

Q. So I think you already realize that a mitigation plan is an incentive to avoid a problem, even though it happens after the fact. So you would agree, then, though that a plan up front would be an incentive too, if there were some liability following for not following it?

A. The plan, in my mind, did not address the cause of -- of the emergency or malfunction that occurred. Therefore, that's why you'd have to adjust that plan. Okay?

You cannot possibly -- you don't necessarily plan for all things that could occur out there, all malfunctions, all emergencies, that could -- a lot of times what you do is you plan how to react to them.

You know, the main thing at one of our plant sites is when you have an issue -- let's say you would have too many liquids coming into a compressor station and it fills up the separator.

It's going to trigger a high, high alarm. It's going to isolate and shut down the process equipment promptly, because you don't want any damage to occur. And so it's going to vent the equipment in the plant.

At the same time, it's stopping the flow of gas into the plant, so that's going to be an unscheduled shutdown that we're going to let upstream know, Hey, we're getting too many liquids in here. You-all need to figure out what's going on in your upstream area.

So you know, we can -- we can work with the companies. We adjust our picking schedules, for example, sometimes, to prevent that from occurring. But it's sort of done more on the fly than it is in a specific plan. There is no specif- -- the plan would be to say we're going to be picking on a monthly basis.

And then you find out that really, we need to start doing it every two weeks, in order to operate more effectively and not have shutdowns. So you adjust that plan.

And this says it requires to submit any adjustments to a plan.

Q. Doesn't our plan require you to look for

potential problems before they occur, as opposed to after, which is what your proposal does?

MR. FELDEWERT: Let me object. When you say "your plan," Mr. Ames, what is "your plan"? What are you talking about here?

MR. AMES: The plan proposed by your rule.

MR. FELDEWERT: You're talking about the plan that's identified in 28.8C1?

MR. AMES: I am talking about the plan that Mr. Reinermann is saying is adequate. A mitigation plan. His plan. His proposal for a plan.

MR. FELDEWERT: You're talking about the mitigation plan?

MR. AMES: I just said that.

MR. FELDEWERT: Okay. Thank you.

A. I'm ready.

So basically, the mitigation plan would effectively have two parts to it.

It's going to have a corrective action plan, being what are you going to do to correct the situation as it currently stands?

The next part is, it's going to have a preventative plan in it. Because it's something that you have not foreseen occurring out there,

because it's never occurred before. And so you're going to try to devise a way to prevent it from recurring.

So that mitigation plan would have the correction -- a correction plan to it and a preventative maintenance program associated with it, or a preventative program for it.

Q. (By Mr. Ames) Okay. So it's an after-the-fact plan. That's what you want to do, right?

A. No. I have a plan already in place, that you would require me to have in place, that we have for all the categories that you have listed here.

Pulling that all together is a monumental task. It's a lot of paper that, frankly, I don't -- I don't think I would ever wade through it.

When we have an issue occur at a -- at a site, we do periodically get asked by BEDQ, sometimes NMED, about -- we'd like to see the last time you did maintenance on XYZ equipment. How are you going about doing it?

And we would provide them with the maintenance documentation that we kept for that site.

So it's typically done -- it's -- we have

a maintenance already in place. We've done it. It just so happens that we had a mechanical breakdown that we did not think would happen because we're doing our preventative maintenance that we're supposed to be doing.

So you would see a preventative maintenance plan and say, Did you do the preventative maintenance plan on the pump?

Yes.

Well, why did the pump break?

Well, the pump runs at 3,000 RPM and, you know, it -- when it has an issue mechanically, it can break. It's sort of like a car engine. You know, if it runs too often, you can have issues with it that you just don't foresee.

And what are you going to do to prevent it?

Well, that -- we would have to look into it and see how we're going to do a better job with it.

Q. And the operators who don't have plans like your company, what about them?

A. I'm unfamiliar with folks -- with companies that don't have operation and maintenance programs and procedures in place.

If you look at almost -- you know in midstream, if you look at almost -- if you look at the oil and gas GCP permits, we're required to have maintenance programs out there. We're required to have NM programs out there. We're required to keep those programs. We're not required to submit them all, but we're required to have those plans.

Q. You just don't want to give it to us, because you don't think we can handle it.

Is that what it is?

MR. FELDEWERT: Object to the form of the question. That misstates his testimony, Mr. Ames.

MR. AMES: Well, he said he didn't believe that the OCD had the wherewithal to handle the plans.

HEARING OFFICER ORTH: Okay. Go ahead.

A. Okay. I don't think it would -- I don't think it would benefit the goal of this program to reduce emissions at all by handing over all of these plans, I think -- I've heard some companies' plans for OCD to have.

I don't think that those plans would be worthwhile to have in your hands. It's going to be that case-by-case basis, where you're going to want to look specifically at the problem child and

address the problem child.

Q. (By Mr. Ames) After the fact. Okay.

MR. AMES: Thank you. That's all I have.

THE WITNESS: Thank you, sir.

HEARING OFFICER ORTH: Thank you, Mr. Ames.

Mr. Biernoff, do you have questions of Mr. Reinermann?

MR. BIERNOFF: Madam Hearing Officer, I do not have any questions for Mr. Reinermann.

HEARING OFFICER ORTH: Thank you.

Ms. Fox or Mr. Baake, do you have questions for Mr. Reinermann?

MS. FOX: Thank you, Madam Hearing Officer. I have a couple.

EXAMINATION

BY MS. FOX:

Q. Good afternoon, Mr. Reinermann.

A. Good afternoon, Ms. Fox.

Q. Thank you for your testimony.

Mr. Reinermann, you've testified, at the beginning of your testimony, with regard to the definition of emergency?

A. Yes, ma'am.

Q. In 28.7D.

A. Okay.

Q. And you testified regarding an exception to that definition 28.7D5, which reads, in terms of OCD's proposed language, and exception to the definition would be what would include the operator's negligence, including a recurring equipment failure.

Do you recall that testimony?

A. Yes, ma'am.

Q. And you're proposing that the phrase "including a recurring equipment failure" be struck, correct?

A. That's correct.

Q. And you testified that you believe that should be struck because you believe "recurring" means more than one time, that it could be two times; and, therefore, two times wouldn't be fair to -- to count as negligence.

Is that essentially your testimony?

A. Yes, ma'am.

Q. And did I understand from your testimony, then, that if the equipment failure were a pattern, or occurred multiple times, that you would support operator's negligence as an exception to the definition of emergency?

A. I don't recall saying that exactly. I do recall saying that the OCD witnesses that spoke about being a pattern of equipment failure, which means, to me, multiple times occurring.

You know, this isn't within 60 days, either. This is for the life of the facility. So if I have something break down this week and I have something break down next year and the next year, the following thing, you know, or related to it, I have trouble seeing that as either recurring or negligence at all.

We have lots of large mechanical equipment out there. I am specifically thinking about our engines that we have out there, and turbines, that are very complex pieces of machinery. And that -- that I would not support saying -- I only support striking that language in there, not even changing the word to "pattern."

Q. So if, for example, there were a pattern of equipment failure, you don't think that OCD could attribute that pattern, that recurring pattern -- say it happens 10, 15, 20 times -- to operator negligence.

Is that correct? Is that what you're saying?

A. So when we report excess emissions to NMED, which -- which is similar to what occurs here when you have this recurring pattern going on, is you report each incident that happens, or you report it to the state of Texas.

Q. Is this related to the definition of emergency? Because I'd like to keep the witness on track.

I asked a pretty specific question.

A. I'm sorry. Could you please repeat the question?

Q. What I'm wondering is, I thought the implication of your earlier testimony was that you would support including language to the effect of, if the operat- -- if equipment failure were a pattern or repetitive, you might support adding -- changing the definition to include that.

But you just told me no, that was not what you testified to.

And I just asked you for further clarification as to whether, in terms of this particular definition of emergency, and the extent to which when equipment failure occurs repeatedly, whether that should ever count as operator negligence. Say for example, there's equipment

failure, you know, 10, 15 times, the same piece of equipment?

A. Yes, it could.

Q. And then in terms of your -- your definition of recurring, as I recall, is if it occurs -- if equipment failure occurs more than once, could be two times, correct?

A. That's correct.

Q. And before you gave us your own definition of recurring, did you bother looking in a dictionary for the definition of recurring?

A. I -- I did not.

Q. So let me just read to you, from Merriam Webster, which is an online dictionary -- I'm glad to submit this if need be for the record.

But their definition of recurring is:

"Occurring repeatedly, happening or appearing multiple times."

And so would it surprise you that that's the dictionary definition of recurring?

A. No, ma'am.

Q. Mr. Reinermann, you also testified with respect to language proposed by Climate Advocates in 28.8B3A.

A. Yes.

Q. And so that language has to do with exceptions to the prohibition on venting and flaring, correct?

A. Yes.

Q. And one of those exceptions, as proposed by OCD, is scheduled repair and maintenance, including blowing down and depressurizing equipment to perform repair or maintenance, correct?

A. Yes, ma'am.

Q. And Climate Advocates is proposing a caveat to that exception to include the following language:

"But only where the gas cannot be rerouted back into the pipeline outside of the depressurized zone or otherwise beneficially used."

You provided testimony on that proposal, correct?

A. Yes, ma'am.

Q. And I believe in -- I believe Mr. Feldewert asked you whether existing gathering lines are configured to accomplish this.

Is that correct?

A. That is correct.

Q. And you said that as far as you're aware, gathering lines are not currently configured to

accomplish this purpose, but that some -- but the transportation line -- you're aware of transportation lines that are.

Is that correct?

A. I am.

Q. Now you did not testify, did you, that it is not technically infeasible for gathering lines to be configured to accomplish this, did you?

A. No, ma'am.

MS. FOX: That's all I have.

HEARING OFFICER ORTH: Thank you, Ms. Fox.

Mr. Paranhos?

MS. PARANHOS: Thank you, Madam Hearing Officer. I do have just a few questions.

EXAMINATION

BY MS. PARANHOS:

Q. Good afternoon, Mr. Reinermann.

A. Good afternoon.

Q. You provided testimony regarding NMOGA's suggestion that OCD add a provision that explicitly allows for them to remove flaring from fugitive emission components, such as valves, flanges, connectors, in 28.8B3H.

Is that correct?

A. Yes, ma'am.

Q. And I believe you testified that NMOGA's intent for this provision is to apply to normally operating fugitive emission components.

Is that correct?

A. That would be correct, yes, ma'am.

Q. Thank you. And can you clarify for me which fugitive emission components you believe leak during normal operation?

A. Well, a valve will leak. A flange will leak. Other components will leak.

Now the thing is, are they above what's referred to as the leak threshold that requires them to be repaired under a rule?

So the ones that I would consider to be normal are the ones that we typically are permitted, that we do not have to take any type of action to correct.

Q. Thank you.

And you also testified that fugitive emission components may malfunction, and that leads to leaks, and that such leaks stemming from malfunctioning components are not covered by your proposed -- or by or NMOGA's, I'm sorry -- proposed exception.

Is that accurate?

A. That would be correct.

Q. Great. And just one point of clarification.

As you look at NMOGA's suggested language, is it specific that fugitive emission components in the exception only refers to normally operating fugitive emission components and not malfunctioning components?

A. I would say that it's not that clear. If that -- the word "normally" would be a better way to do it.

MS. PARANHOS: Thank you so much.

Those are all my questions.

THE WITNESS: Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Paranhos.

Commissioner Engler, your questions?

COMMISSIONER ENGLER: Thank you.

Mr. Reinermann, I do not have any questions. I want to defer to Chair Sandoval, who is much more an expert on midstream than I.

HEARING OFFICER ORTH: Thank you.

Commissioner Kessler?

COMMISSIONER KESSLER: No pressure for that on me. I was also actually going to say that

I'm going to defer to the chair, who I'm sure will do a good job.

I don't have any questions.

Thank you for your testimony.

THE WITNESS: Thank you, ma'am. You're welcome.

HEARING OFFICER ORTH: Madam Chair?

CHAIRWOMAN SANDOVAL: There's really no pressure at all.

EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. Okay. I also have another minute to get my notes in order, but we can start rolling.

Okay.

A. Good afternoon.

Q. Good afternoon.

Can we go back to this definition of emergency?

A. Yes, ma'am.

Q. Let's see. So you talk about -- let me find the page on here. It was Example 2. It was the PSV. And your -- it was the PSV example on F8.

A. Right. Yes, ma'am.

Q. And what you stated in your testimony was that that would be considered negligence.

Is that correct?

A. No, that it should not be considered negligence. That we did do proper operation and maintenance of that PSV when it released.

Q. But it would be counted against you under this rule.

Is that correct?

A. Under the rule, in this case for this one, because it happened -- well, you -- so the rule, as it's written, says three or more in the system, basically. So this would be two -- it depends if I had taken any other ones in the system already.

So if I had already a couple of releases from the system, then they would count against me.

Q. Okay. So maybe I misunderstood your testimony. I had thought -- or it had sounded like you were saying that would fall under negligence and not be a, quote, emergency.

So you're clarifying that you do think, as long as you've requested your three, that would count as an emergency.

A. So the thing is, is that -- reading the rule, 5 says operator's negligence, including a recurring equipment failure. So this is one where the PSV failed twice.

So the next one says three or more emergencies. And if this was an emergency, when a PSV pops, so you take it out. That's activated and it's released.

So in some respects, you have -- both categories fit the release.

Q. Okay. So you -- I think we talked about this a little bit, or Ms. Fox talked about it a little bit.

NMOGA is opting to, on 5, for the op- -- Number 5, to get rid of the -- the recurring equipment failure.

Now, I can understand where there may be a line of a recurring equipment failure that is negligence and a recurring equipment failure that is not.

Do you -- is there a way to craft language which would delineate those things?

A. Well, see -- the operator shall...

Q. I think you, in your -- you've demonstrated some examples where -- and some ambiguity with the term "recurring."

But I'm not hearing a solution. And so that's my question.

Do you have a solution, other than just

slashing that language?

A. I think slashing the language is best. And the reason is, I think it should be done on a case-by-case basis. Okay?

So when you're -- when you're trying to -- if you're saying that we have operator negligence, I don't think an operator is going to call that on himself. That's going to have to come up when the C 115B gets reviewed and there's questions as to why you're not achieving a 98 percent capture efficiency.

We don't have it necessarily as a category, but that could come up in the questioning, as to -- as to that.

So I don't think anyone will really think about things being too much as operator's negligence. Because again, we try to operate and maintain systems. You know from your days at Marathon how we try to do things out there to stay in compliance.

So with regards to the negligence part, I think striking that last part is the best bet. And doing it on a case-by-case basis, when OCD is looking at doing a review of documentation associated with the annual reports.

Q. So -- but the definition, as written, it doesn't -- it doesn't allow for a case-by-case basis, does it?

A. Well, I think you've pointed out that OCD has enforcement and enforcement wherewithal -- enforcement-- oh, what's the word I want to use there?

Q. Enforcement discretion?

A. Enforcement discretion, yes. Enforcement activities that they can employ.

So when they would see that someone is not achieving 98 percent capture efficiency, or not meeting their progress, they'll be asking about -- about their -- about the emergencies that occurred out there. Why did you have so many? What were the reasons?

And you could look at them and say, Here's where they're at.

Q. Okay. So the other clarification -- you're, I think, as- -- the requirement asking for is in 6, where it says three or more emergencies at one site for similar causes -- not at one site for similar causes -- has been added by NMOGA, experienced by the operator within the preceding 60 days.

Do you feel like that could be taken advantage of by operators?

A. No, ma'am, I don't. We are required already, under NMED rules, to keep track of our venting that we have going on from our facilities and the reasons why they occurred.

So we would have an accurate accounting of that type of activity, and you would be able to get those specific records, oil and gas GCP permits.

Q. To cross-reference, you mean? Like if OCD wanted to cross-reference that information?

A. Well, you can -- you can ask for information regarding your -- your logs that you keep for NMED, I would think, to determine how you're doing with the rest, keeping track of emergencies, to make sure you're not misclassifying things when you're reporting them up the line in the C 115B.

This will be a different kind -- can you hear me still? Did I close out?

(Technical difficulties.)

(A recess was taken from 3:49 p.m. to 4:03 p.m.)

HEARING OFFICER ORTH: Madam Chair, can you hear us?

(Discussion off the record.)

HEARING OFFICER ORTH: So if you will proceed, the -- with Mr. Reinermann, and we'll try to wrap this up here.

CHAIRWOMAN SANDOVAL: Just let me know if you can't hear for some reason.

Q. (By Chairwoman Sandoval) I think Ms. Paranhos hit on this a little bit. So we talked about fugitive emissions. And we talked some with Mr. Smitherman previously. It's at 28.8 --

A. B3.

Q. B3. Yeah.

And I think you hit on it in F15 of your testimony -- or I'm sorry, your exhibit.

If the word added somewhere else in here -- I think it's "normal operations of," would that meet the intent of what NMOGA was trying to do, add similar language to what's added in front of the dehydrators, the AMIEE unit, that sort of language, would that still meet the intent of what NMOGA was trying to do?

A. Yes, ma'am.

Q. Okay. So essentially, it would say something like normal operations of fugitive emissions component?

A. Correct.

Q. Okay. I am trying to find out where that is.

MR. FELDEWERT: Madam Chair, this is Michael Feldewert.

I think you'll find it in 28.8D. Okay?

CHAIRWOMAN SANDOVAL: Yeah. I think it's on page 5 of the black binder. I finally put my hands on it.

MR. FELDEWERT: And then you'll find similar language in Part 27 as well, in a comparable provision in Part 27. Okay?

CHAIRWOMAN SANDOVAL: Okay.

Q. (By Chairwoman Sandoval) As we talked about this in Mr. Smitherman's testimony as well, you say fugitive components such as the valves, flanges, and connectors.

Is that the complete list --

A. No, ma'am.

Q. -- of components?

A. No, ma'am. There are other components. Compressor vents would be one. Compressors have fugitive components. They just don't vent. But they also have rod packing emissions and other things that are considered to be normal.

You have pumps that could have drips or drabs. That would be also a leak that might have some gaseous component to it.

So there are other types of fugitive emission components than those three.

That's why the word "such as" is a good way to indicate it.

Q. But without actually having a definition for this, how does the rule ever confine it?

A. I would guess you would say what is normally considered, in practice, to be a fugitive emission component from a -- from a compressor station that's subject to Quad-OA defines what a fugitive emission component is.

You would find a list there that everybody would say -- that list is the one that everybody would point to and say, Those are fugitive emission components.

Q. But I think as you pointed out, OCD is -- does not regulate emissions, do they?

A. They regulate releases, so they do regulate emissions. They're requiring us, by Part 29 right now -- by Part 29 with their C 141, whenever we have a release we're basically doing that release of gas to the atmosphere which is, in

my mind, emissions.

Q. But not within the confines of the OCD rule, correct?

A. Well, the OCD rule is going to basically have us -- they're going to limit our waste, if you want to put it that way. I think of emissions as being waste in a lot of respects.

Can you hear me okay, Madam Chair?

Okay. Great.

Limits our -- they limit our emissions, or our waste, basically, by these rules.

So in -- you know, what is the natural gas that we have emitted from our sites, when it emits? It's due to normal operations that don't see the beneficial use. Some of it is due to fugitive emission components.

So in a way, we are -- we have to be accountable for our emissions, for our ventings that we have.

Q. So -- so you've mentioned rod packing. Would rod packing vents fall under B, normal operation of a compressor or a compressor engine and turbine?

A. That's -- for me, when I look at Quad-OA, they make a distinction between the two.

And also, when you're talking about excess emissions, because a lot of times what will happen is that a compressor, when it shuts down, will be isolated and vent.

That's not necessarily the rod packing vent that's going on semi continuously. So it's a different piece of the compressor.

Q. Understood. But couldn't the rod packing vent be put in that category?

A. It could. I could see how you could do that.

Q. Are there other types of fugitive emissions components, as you term it, that would not fit in any of these other buckets?

A. Well, valves, flanges, and connectors clearly don't, and so they would not fit in those buckets.

Q. Understood. Okay.

So other than valves, flanges, connectors, and -- anything else that would fit under these standard categories that are already there?

A. That's correct. I think the word "such as" is a good phrase to use, because there could be some additional ones. I'm trying to --

Q. You don't think, though, in that sense --

A. We have -- I'm sorry.

Sampling systems can also be a type of fugitive component. That's a listed one, is a sampling system.

Q. But don't you think, if you listed emissions components as not clearly defined, then there is -- to use Mr. Smitherman's term again -- the potential for mischief by operators who are not the most prudent?

A. I don't know. It is -- I can't speak -- I know that Enterprise would not be doing that type of activity.

Q. But there is potential that other, maybe less reputable, operators could. That that door is open.

I know that you don't have experience, but you're saying that door could be open?

A. I think if you look at any rule that's out there, people can try to make any type of loophole that you want.

For example, you just said, Well, rod packing, doesn't that fit under compressors?

Well, yeah, it does. I'll go ahead and check that one off. It's taken care of. You know, you have things like that that, you know, you can

read in the rules.

It's -- for example, you might be getting to another part of the rule that we read about that you might get into as -- with regards to the -- hold on one second.

Oh. With regard to the C 129 and the 50 MCF, and having to report that onto a map.

I would -- frankly, everybody that I know of in the NMOGA group read that to be strictly thief hatch emissions that were reported on the new C 129 form, not that were -- that's all inclusive of emergencies, where you might group them together, the smaller ones.

So nobody read it that way.

So it's -- then, you know, you have to come out with some type of guidance for us as to how to read this part of the rule that's not being well read right now. That happens all the time with rules and requirements. There's interpretations done on rules and regulations quite a bit.

Q. Understood. Okay.

Let's pick on the fugitive emissions component.

A. Yes, ma'am.

Q. I know it's rather common, I think, in --

in some of the processing plants, it's becoming more prominent. They're common in the refineries at this point.

Are operators looking to or utilizing low-emission valves?

A. We will specify valves that meet the requirements of what we have to put into a system.

For example, when we build a brand-new natural gas processing plant, like we've done in New Mexico, as well as in the Permian Basin area, they had to be designed with valves that were less than 500 parts per million.

So in that case, yeah, we would use -- we'd spec out those -- those lower-emitting valves.

Q. Do you do that at compressor stations as well, or just processing facilities?

A. With regards to compressor facilities, we don't want valves to leak, plain and simple. It's a safety issue if they leak too much.

So as far as what is actually specified in our building for a compressor station, I cannot speak to that. I can only speak to ones that we have with the larger plants we build.

Q. So you're saying the NMOGA -- the NMOGA rule here is saying there should be an allowance for

fugitive emissions components because they leak at low levels as a part of normal operations, correct?

A. That's correct.

Q. But what about on newer facilities? Understanding the low emission valves still can leak, wouldn't it be less potential waste to use Low-E valves on all types of new facilities?

A. Well, I think that this type of regulation might drive you to that decision, because you have to have capture efficiency that you're going to have to get. You want to make sure you're capturing it all and having -- you're going to be doing AVOs under the program for any proposed draft program.

The NMED will be going out there with leak detection equipment, like OGI and other things. OGI typically is good to less than a thousand, 2000 parts per million. It depends on the flare camera that you're using.

So you know, we would be needing to have those -- those type of components out there like that, that would meet those requirements.

Q. Okay. So you're saying that it may be necessary in the future to install Low-E valves on new facilities?

A. That, and existing facilities. Because

it -- my experience has been with Quad-OA. We had a brand-new -- sorry.

We had a facility become subject to Quad-OA because we added horsepower to move the gas. That triggers Quad-OA for a natural gas compressor station.

And so basically, we had one new compressor, but then we had a whole bunch of other equipment out there.

So when we went out there with our flare camera the first time, we found a number of valves that needed to be either replaced or tightened up or fixed to do that.

So on a case-by-case basis, looking with the flare camera, you would go and replace those valves with ones that you know would not leak any further.

Q. Okay. So is that -- is that what the retrofitting process would be? Could you describe what, I guess, that retrofitting process would be for existing facilities?

A. Sure. There's a -- I'm going to talk about the -- a gas plant I'm very familiar with that became subject to ESPS 40 CFR Part 60, Subpart KKK, and -- back in 2012.

So when it became subject to that rule, we first did our monitoring. We had about -- out of 6,000 components, we had about 100 that we had to replace; valves, basically.

So basically, we went on what's referred to as delay of repair. You might have heard of delay of repair.

So once we did delay of repair, and -- basically, when there was a plant shut down, there was 109 valves out there ready to get replaced and put into play, so that basically they would then have it.

Today that facility has no complaints on DOR.

The one thing I found interesting was in that replacement project, we replaced one control valve that cost $75,000, a brand-new valve. And you know what that valve did when we put it in service? It leaked. It leaked like a sieve.

However, it was a new valve, so it had packing and things like that, that you could adjust to make it where it was leak free.

So you -- you can -- you know, the fugitive program that -- more so than NMED has, than that you all have, it's going to drive things with

regards to reducing fugitive emissions out there.

Because they're saying to go -- to go out there with a flare camera and evaluate things.

You don't have that in your rules.

Q. Understood. Would it be reasonable, as valves need to be replaced at facilities via a compressor station or a processing plant, that they should be replaced, when possible, with Low-E valves?

A. I think that -- I believe the following best practices. And it talks about best practices in this rule.

If that is a viable technology that is required, then yes, it should be. Otherwise, I think that utilizing a technology that meets the requirements is sufficient.

Q. Okay. Do you have any experience with Low-E valves at production sites?

A. No, ma'am. Not that I'm aware of.

Q. Okay. Moving on a little bit to AVO.

Okay. And your Exhibit F22 -- and by "your," I mean NMOGA's Exhibit F22.

A. Yes, ma'am.

Q. It says a number of things.

AVO inspections are intended to address

air emissions, not surface waste.

Is that correct?

A. My experience is that AVOs are for addressing air emissions and reducing air emissions. That's -- that's been the predominant reason for them.

This rule brings them into another area.

Q. So maybe it would be more accurate to say something like AVO inspections are previously intended to address air emissions, not -- you know, like, not surface waste, until now?

A. That probably could be a good way to write it.

Q. Okay. So let's just run through a scenario, though.

If you have a valve or a flange or a connector, or whatever you want it to be here, that is -- is leaking. You know, you -- maybe you go out there and you view your AVO and you smell something or you hear something, and you know something is up. Maybe you confirm it with a camera. However, you would do your operational practices, et cetera, and you find a valve, connector, flange, et cetera, that's leaking.

If that valve, connector, flange,

et cetera, had not been leaking, would that gas that is now leaking out still be in the pipeline or in the process?

A. Again, it depends on the piece of equipment. It could be in the fuel system that's going to get burned for beneficial use.

So it -- it could be in the dehydration unit. It could be in the ambient unit that you have out there.

So it does not necessarily have to be gas or a leak that would be part of a piping system where the pipes come in and out of a compressor station.

Q. I said pipe or process.

Would it still be in process, you know, somewhere in the process there?

A. Yeah.

Q. Looking at a process flow diagram or, you know, you're looking at where everything is going. That -- if that valve, flange, or connector was not leaking, that gas would still be in the process, be it to go to your beneficial use on the heater trigger or whatever it may be?

A. Yes, ma'am. Yes, ma'am.

Q. Okay. So when it says with NMOGA here --

and I think NMOGA has made statements previously trying to assert, maybe, that it's not surface waste.

But what I'm hearing from you, correct, is that it would actually still be in the pipe, or the process, if there wasn't that leak?

A. That's correct. It would be.

Q. Okay. So that is or could be, as you said, beneficial use or salable gas, correct?

A. Yes, ma'am. It could also be going to a control device.

Q. It could be. Which could make it waste, if it is coming out of a leaking connector, flange, et cetera?

A. That's correct.

Q. All right. Thank you.

So AVO inspections, then, I think is kind of winding this up -- actually can prevent waste and aren't just associated with air emissions?

A. If -- yes. Because the way we've talked about it here is that that leak from an AVO leak that you find is, by definition in my mind, if you look at the definition of malfunction, it's a malfunction. So you would -- you would keep that leak down there and you would -- you would report

that in the malfunction category in your C 115B.

Q. Okay. Thank you.

A. Yes, ma'am.

Q. I think you said midstream operators are -- I want to make sure I got this down correct -- are typically on site once a week on average?

A. Yes. Yes. It's a lot more than that, but yes, ma'am.

Q. So -- and similar to the question that I asked Mr. Smitherman, would it be a more reasonable jump to jump to AVO every other week as opposed to once a month?

A. So the -- the definition -- no, I'm sorry. It's not the definition. The definition of AVO is very simple in the rules -- audio, visual, olfactory. That's it. That's the definition.

The rule itself, though, talks about visually inspecting externally for cracks and holes. It doesn't matter if the crack or hole has a leak. It might just be a small surface crack.

Loose connections, then leaks. So we're not just visually looking for leaks. We're almost doing a quasi engineering look at things out there. It's really going over the equipment with a

fine-tooth comb up front, with it up front and personal with it almost.

Because when you're looking for leaks, you're listening for things and smelling for things. You're -- you should have a defined path to walk through the facility, like you do with Quad-OA, and to basically make sure you're checking out all the pieces of equipment and see if you have any smells, any drips, anything that looks like a leak.

But to go and specifically look for a -- broken access covers, things like that, it's hard to see that unless it's actually leaking.

So if the rule would just say visually inspect for leaks, I could be supportive of doing it every two weeks or twice a month on it, without a doubt.

But the way the rule is, there's a lot more detail than in a checklist for doing a visual part.

Q. So I -- I hear you. Would it be more reasonable to do something such as that detailed inspection? You know, you check for cracks -- oh, I don't have the language right in front of me -- but all of that detail listing, once a month.

But every time you're out on site with

that operator there, once a week, you're just doing, you know, your audio, visual, olfactory. Do you see something? Do you hear something? Do you smell something?

Would that be more reasonable?

A. Yes, ma'am. In my mind, it would be.

Q. So having maybe a tiered system might be more practical?

A. Yes, ma'am, it would be.

Q. Okay. Thank you.

HEARING OFFICER ORTH: Madam Chair? I'm sorry to interrupt you. It's almost 4:30, and the technical host did let me know that both of the two public commenters we have are on the line.

I didn't know if this was a good place to take up --

CHAIRWOMAN SANDOVAL: I have a couple more questions. But if you want to break and do the comments right now, that's fine.

HEARING OFFICER ORTH: All right. Thank you very much.

So good afternoon to our two public commenters.

As you know, this is Case 21528. And I will call you in this order. Crawford MacCallum,

and Anna Hansen.

So, Crawford MacCallum.

Mr. Garcia, would you unmute him?

MR. MacCALLUM: Am I unmuted?

HEARING OFFICER ORTH: I can hear you, yes.

And if you would please spell your name before you begin speaking, and try to keep your comments to just a few minutes.

MR. MacCALLUM: I am Crawford, C-R-A-W-F-O-R-D. MacCallum is M-A-C-C-A-L-L-U-M, of Tijeras, Bernalillo County.

Good afternoon, members of the commission, Madam Chair, and all present.

Previous comments to the commission have already covered the harm being done to public health and climate change by an increase in emissions of methane.

Rather than repeat previous comments, I come before you this afternoon to frighten you. Climate change is already here, and I won't repeat them, as we are concerned with the future.

At some time, close to the end of this century, we will be struggling in a different world. Most of the cities will be underwater, world

agricultural production and distribution will be in disarray, and the heatwaves will be common. New diseases will emerge, and a military strike will be coming, et cetera.

But until this time, the dangers are understandable, and to some extent predictable. But at this time, computer calculations that the arrival of tipping points -- more certain. The tipping point is a phenomenon which beginning time cannot be predicted, but which are substantial and irreversible.

For example, this is an exclusionary permanent force material which releases methane and CO2, which raises the temperature, which increases the rate of exposure and so on.

A dozen or more other tipping points will come later. At some time, hopefully in the next century, we will begin to slide into an unpredictable and uncontrollable future.

Foreseeable points from there are the stuff covered -- with ocean -- is considered --

HEARING OFFICER ORTH: Mr. MacCallum, I'm sorry. Your last sentence was broken up.

Would you start from the beginning, please?

MR. MacCALLUM: So at some time, hopefully in the next century, we will begin to slide into an unpredictable and uncontrollable future.

Stable end points from there are the stuff of science fiction, a second runaway to unlikely -- a sea world governed with ocean, is considered likely.

Well, if the sky is falling, the end is nigh, then why worry about collecting methane in the Permian?

Typically, because anything that can slow down and ameliorate the story -- I can understand that, that is the changes.

I thank the commission for your time.

HEARING OFFICER ORTH: Thank you very much, Mr. MacCallum.

Ms. Hansen?

MS. HANSEN: Thank you.

Can you hear me?

HEARING OFFICER ORTH: Very clearly. Thank you.

MS. HANSEN: Thank you.

I'm speaking to support Governor Michelle Lujan Grisham's call for a nation-leading methane reduction rule. To achieve that goal, the Oil

Conservation Commission must strengthen the Oil Conservation Division's proposed methane rules, methane waste rules, to eliminate unnecessary waste and pollution.

The final rule must achieve three key goals.

One, the ban of routine venting and flaring, and only allow such activity when necessary for health and safety, and require flaring over venting, except when necessary for health and safety.

Two, require oil and gas companies to capture 98 percent of methane emissions by 2026 or sooner.

Three, strengthen state reporting and public notice requirements to improve transparency and ensure accountability of oil and gas operations.

Methane is a powerful greenhouse gas that is responsible for more than 25 percent of the climate change we are experiencing today.

Oil and gas companies release more than 1.1 million tons of methane, which has the same climate impact as about 25 coal-fired plants.

Methane is also the primary component of natural gas, which means when methane is wasted, it

costs our schools upwards of 43 million in royalties and tax revenue.

The 2020 New Mexico climate strategy progress and recommendation reports reveal that the oil and gas sector generates 53 percent of all greenhouse gas emissions in the state, more than twice the amount that was previously estimated, and I believe it to be higher.

Critically, the climate strategy report finds our current and proposed climate strategies will make a significant dent in our greenhouse gas emissions profile by 2030. But reaching our target will require renewed ambition and additional action.

To achieve our goals, the oil conservation committee should require green completion to minimize methane emissions during completion and recompletion.

Toughen provisions to ensure that flares stay lit and work properly at all times, preventing methane from being vented into the atmosphere.

Require operators to immediately notify persons in communities and communities at risk when methane releases threaten public health and safety or the environment -- and the environment.

Deny permits to drilling new wells if

operators are out of compliance with gas capture requirements.

Operators should be required to invest funds in complying with their legal requirement to prevent methane waste and pollution before they drill new wells.

Prohibit routine venting and flaring during pipeline maintenance and repair, and only allow for flaring if necessary for safety.

Ensure that all leaks are repaired through the ALARM program are verified by an independent third party, to ensure the integrity of the program.

While voluntary ALARM holds promise in incentivizing technological innovations, these programs are not a substitute for mandating leak detection and repair requirements, a most important tool for reducing methane leaks.

Since nearly 70 percent of oil and gas methane pollution in New Mexico occurs through leaks, it is critical that the New Mexico environment department adopt a rule that holds polluters accountable and cuts emissions across the oil and gas supply chain.

NMED's draft rule fails to protect public health and our climate by exempting 95 percent of

wells from regulation across the state from oversight and basic leak detection and repair requirements.

The commission should make clear that the agency must work in parallel to achieve comprehensive rules that cut methane and air pollution.

It's very simple. If you leak, you don't frac, you don't drill. That is it.

You know there's no excuse, not in this day and age, for this type of release of methane.

Methane is having a huge impact on the climate. And the arctic is melting; and, therefore, more methane is being released than is actually being reported, because we are way behind in capturing methane.

So I ask you, please, to make these rules stronger immediately.

And I thank you for your time.

I'm Santa Fe County Commissioner Anna Hansen. And if you need me to spell my name -- I know it's spelled properly on the screen.

HEARING OFFICER ORTH: Yes, please. It's H-A-N-S-E-N.

MS. HANSEN: Yes, correct.

HEARING OFFICER ORTH: Thank you very much, Commissioner Hansen.

Those were our two public commenters for this afternoon. There are two additional opportunities each day, each subsequent day of the hearing, at 8:30 and at 4:30.

So far we don't have any commenters tomorrow morning at 8:30. We do have two more at 4:30 tomorrow afternoon.

So, Madam Chair, if you would, please -- sorry for the interruption -- resume your questions of Mr. Reinermann.

CONTINUED EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. Can you hear me?

A. Yes, ma'am, I can.

Q. All right. Great.

So one of the things you said was that you don't actually know all of the locations of your gas pipelines, particularly some of the smaller ones.

Is that correct?

A. I said that I don't. I don't know of them exactly. But as a company, I'm pretty sure everybody would know where the meter begins at to where it gets to the trunkline at.

So I apologize for misstating that.

Q. Okay. Just confirming, Enterprise, in general, should know where their pipelines are, correct?

A. Right. Yeah. We've got about 283 meter stations. And from that meter station on, we know where that line is. Yes, ma'am.

Q. Okay. That's good.

So going to -- I think it's page 8 of NMOGA's Part 28. That proposal by NMOGA is -- is proposed, number three, to strike the word "instruments"?

A. What section are we at, ma'am?

Q. I'm sorry. It's at the bottom of page 8. I think it is 28.8C -- I think it is C3 in the proposal by NMOGA.

It's annual monitoring of the pipeline?

A. Correct.

Q. And I think NMOGA is proposing to strike the word "instrument"?

A. That's correct.

Q. What would a non instrument phase review entail?

A. Sure. OCD reflected that in their Exhibit 3A, an aerial visual inspection. An aerial

visual inspection will fly the line and look for dark spots on the line that indicate a leak.

That would be one example of that.

Q. Okay. What are some of the other options that you might use to inspect the line?

A. I understand that some aerial inspections -- I do not -- I do not have a lot of familiarity with this. I'm not in the transportation compliance group. But they do do aerial inspections with a flare camera on it, to look for methane coming from the ground.

That would be another way to do that.

Q. So that actually, I think, segues into my next question, then, I think when it came to talking about the performance standards.

So it's that same Section 28, at 28.8C -- or 3C. Yeah. So this is the plan, you know, with the -- you know, to detail out procedures to review leaks, et cetera.

So you said throughout the company, you know, a lot of different groups have plans to manage these pieces.

Is that correct?

A. That's correct. You know, we have -- yes, ma'am.

That's correct.

Q. Is there ever a gathering of all of these groups in one location to discuss the different components of all of your plans that are going on?

A. Well, from time to time, because they -- we do plan things out into the future, preventative maintenance activities.

When they plan on doing an activity such as a pigging event on part of a pipeline they may, at the same time, plan on doing maintenance on another part of the line. So they might bring in a different group to say, Hey, you've got this plan for three months out. We're doing -- we need to do this now. Can you get yours done sooner?

So yes, there is that type of planning and oversight done, because we don't want to interrupt the operations as much as possible. We want to keep things going.

So instead of doing maintenance activities A now and B six months later that requires me to maybe shut in/shut down, you do A and B at the same time.

So there is a coordination. And that is typically done by the supervisor. That supervisor will work with the maintenance people, the cathodic

protection people, the pipeline integrity people, to make sure that those type of things are done in a coordinated effort to minimize downtime.

Q. So from my experience, there can be -- you have got operations, you have maintenance, you have pipeline safety, you may have reliability in there. You're going to have the regulatory people, which could mean environmental, safety, health. There's relia- -- you know, all of these different groups from -- from some of my experience in industry, they did not always communicate that well to each other and there were missteps that happened because of that.

Has that ever, in your recollection of your eight years at Enterprise, ever happened? Did something occur -- you know, one group planned on doing X, Y, and Z, did not adequately communicate it to somebody else, and there was a misstep, either in planning or some environmental ramification, et cetera, because of it?

A. Yes. Yes, but not so much environmental as much as having to shut something down twice and curtail production.

Q. So could having a plan, such as what is proposed by the division, actually help to foster

that coordination and communication within a company?

A. Not that I could see, no, ma'am.

Q. So you see absolutely zero benefit in requiring a forum for all of those five, six -- however many groups -- to come together to make sure that they're coordinated?

A. They do that on a project-by-project basis or pipeline-by-pipeline basis. It's not anything that's written in a general plan or program that's followed.

(Discussion off the record.)

Q. (By Chairwoman Sandoval) So what you just said is, there have been missteps that have resulted in, potentially, shutting a piece of equipment down twice, correct?

A. Correct.

Q. So that would be extra waste, as you say it, because more -- if you had to depressure a unit twice --

A. Sure.

Q. -- that's blowing it down two times, so that's double the amount of waste that may have previously happened, correct?

A. Yes. You asked if it ever. So "ever" is

a fairly large word. So I'd have to say yes to that.

Does it happen frequently? Heck no. It doesn't happen very often at all.

Q. Understood. There are likely lessons learned, things like that, that could happen.

Understanding that.

So -- but you still don't see a huge -- or any benefit to having this coordinated plan?

A. It's not a coordinated plan that's proposed here. What's proposed here is, I'm going to give you a binder for maintenance. I'm going to give you a binder for corrosion. I'm going to give you a binder for this, a binder for that.

None of it is a coordinated effort to say, Here's how we're going to make sure that we do all of the coordination here together.

It's not part of what you would get as what's requested here.

Q. Is there a way to make it more so that other than, I think, what's known in this proposal, which is to do a plan after the fact?

Is there a mechanism to make that plan a more useful plan for the company?

A. I can't envision that, no, ma'am.

Q. So there's no way to make it better, other than to just require it for companies who are not meeting their compliance obligations?

A. We believe that that's the best thing to do, is to require a mitigation plan to correct the problems that you have out there for not meeting your capture efficiency.

If you're not meeting your capture efficiency, if you're not meeting your goal along the way, that, we believe, is the best part.

There's a part of the regulation that talks about if you are not achieving the -- I believe it's 60 percent that you have to get under 19.15.28.8A2. If the operator's baseline capture is less than 60 percent, the operator shall submit, by a specific date to the division for approval, a plan to meet the spec- -- the required annual capture percentage increase.

I would say that that's a pretty low hurdle, 60 percent. But I would also say that you have that idea of a mitigation plan already in the rule right there.

All we want to do is expand it to companies that maybe are 97 percent. How are you going to get to 98? Okay?

You're at 95 and a half. How are you going to get to 98?

Or you've fallen down below 98. What happened last year? How come you're down to 97.9?

So that's where you would generate a mitigation plan. The numbers are the numbers when you report things, and you have to basically know what you need to do to get back into where you need to be at.

Q. Okay. I think my last couple of questions -- and maybe you're not the person to ask this.

But since you have that AVO, maybe on the ALARM program. I think NMOGA proposes to require it only once per year versus twice, to qualify.

Did -- was there any poll of the midstream operators to see if that would incentivize them to do these programs more?

A. Frankly, we don't know what the ALARM program is. There's never been one approved, so it's not real clear what that is.

So it's hard to say one versus two, where you would be at. It depends upon what the individual case is. And I think perhaps maybe, when an ALARM program gets proposed by OCD and is

proposed on a certain frequency, that frequency is the one that got evaluated by OCD before approving the ALARM.

Q. Okay.

CHAIRWOMAN SANDOVAL: I think that was my last question. Thank you for your time today.

THE WITNESS: Thank you, Madam Chair.

HEARING OFFICER ORTH: Thank you, Madam Chair.

Let me ask Mr. Feldewert: Did you have any followup with Mr. Reinermann?

MR. FELDEWERT: I have a little bit, Madam Hearing Officer, yes.

HEARING OFFICER ORTH: Go ahead.

FURTHER EXAMINATION

BY MR. FELDEWERT:

Q. If I could have the ability to share my screen.

Thank you.

Mr. Reinermann, can you see what I put up on the screen, which is the definition of emergency? There was some discussion with Ms. Sandoval about that?

A. Yes, sir.

Q. And she was talking about a potential

solution.

Do you recall that?

A. Yes, sir.

Q. Okay. As you read this definition of emergency, where it says "the operator's negligence, including a recurring equipment failure," would you -- what's the problem with that the way it's written?

A. Sure. The main problem with it is that because you had recuring equipment failure it would automatically lump it into a category of negligence. In my mind it would, yeah.

Q. Okay. So in all circumstances?

A. That's the way it would read to me, yes, sir. I think it should be done on a case-by-case basis.

Q. And if we exclude the language -- and NMOGA seeks to exclude it here -- would that allow the determination on a case-by-case basis?

A. Yes, sir, I believe so.

Q. If the recuring equipment failure was actually the result of poor operations, that would be the case-by-case basis that they could examine?

A. Yes, sir.

Q. Okay. And is that why you think this is

the solution?

A. Yes, sir.

Q. Okay. Now I want to ask you about these fugitive emissions, Mr. Reinermann, but I want to do so in the context of the actual definition of surface waste. Okay?

A. Yes, sir.

Q. Now, I have it up here on the screen in front of you. This is NMOGA's prehearing statement at page 4.

Do you see that?

A. Yes, sir.

Q. And that defines the definition of surface waste as "the unnecessary or excessive surface loss or destruction without beneficial use."

Okay?

A. I see that. Yes, sir.

Q. Okay. So I want you to keep that legal definition in mind as we apply your engineering expertise. All right?

A. Okay.

Q. Okay. Now, Ms. Sandoval -- or Commissioner Sandoval was discussing about fugitive losses occurring, as she said, in the process.

Do you remember that?

A. Yes, sir.

Q. Now, does part of that process of moving -- and when you say "in the process," are you talking about from the wellhead to the sales point?

A. When I -- when I thought of "process," when it was presented to me, I was thinking about, like, a dehydration unit or an ambient unit, not necessarily the process of moving the gas from our meter to where it exits out the system.

No, sir. I wasn't thinking that broadly.

Q. Okay. And that's what I wanted to make sure we are clear about here.

When you look at that process of moving the gas from a wellhead to the sales point, does that process include, Mr. Reinermann, unavoidable losses?

A. Yes, sir, it does.

Q. And when you look, for example at 28.8B3, where the division has carved out distances where midstream operators are authorized to vent and flare. Okay?

A. Yes, sir.

Q. Are those examples of unavoidable losses?

A. Yes. The repair and maintenance, normal operation of gas-activated pneumatic controller,

et cetera, yes, they are.

Q. And we see a similar list in 27.8D5.

We don't need to go there, but you're familiar with that additional list, right?

A. Briefly. It doesn't affect my industry. But yes, sir.

Q. Okay. So looking at that, are well operators, or gathering system operators, are they able to actually get all of the molecules of gas that are produced at the wellhead to a sales point?

A. No.

Q. And when you look at the low-pressure emissions from flanges, valves, connectors, okay, which was the subject of your discussion with Ms. Sandoval, are those circumstances that have unavoidable low-pressure emissions?

A. They -- could you rephrase? Could you say that again, sir?

Q. Sure. That should be clear.

When you look at the normal operation, okay --

A. Uh-huh.

Q. -- of flanges, valves, connectors, what you -- what NMOGA has called fugitive emissions, okay, are those circumstances of unavoidable

low-pressure emissions?

A. Yes.

Q. And are they recognized, for example, by other agencies as unavoidable low-pressure emissions?

A. Yes, sir.

Q. And when you look at this legal definition of surface waste up here on the screen, and apply your engineering expertise of those types of emissions to that definition, do those types of low-pressure emissions constitute surface waste?

A. I do not believe so. Because first of all, the phrase "unnecessary," they are -- they're not -- "unnecessary" is a -- sort of a hard word. But they're basically -- it's part of that flange or that valve, especially valves, to potentially leak.

So it's not necessarily unnecessary, but it's accepted. And it is not considered to be excessive if it is less than the prescribed leak rate. And so I would have a hard time calling it excessive surface loss, because it's accepted by NMED or by EPA under the different programs that they have.

MR. FELDEWERT: Thank you.

That's all the questions I have.

HEARING OFFICER ORTH: Thank you very much, Mr. Feldewert.

Is there any reason not to excuse Mr. Reinermann?

MR. FELDEWERT: Not that I'm aware of.

HEARING OFFICER ORTH: All right. Thank you very much, Mr. Reinermann, for your testimony.

You are excused.

THE WITNESS: Thank you, Madam Hearing Officers, and commissioners.

HEARING OFFICER ORTH: I'm not sure if the commission chair had a point to correct the audio issue.

Let me ask the other two commissioners, though.

Do you have an opinion as to how late we should go tonight?

I'm not suggesting anything past 6:00.

Oh, Madam Chair.

(Discussion off the record.)

(A recess was taken from 4:58 p.m. to 5:08 p.m.)

(Witness sworn.)

HEARING OFFICER ORTH: All right. If you would spell your last name, please.

THE WITNESS: C-R-A-F-T, like the cheese, but with a C.

HEARING OFFICER ORTH: Thank you very much.

Mr. Rankin?

MR. RANKIN: Thank you, Madam Chair. I'm moving quickly to get my exhibits together for Mr. Craft.

Madam Hearing Officer and commissioners, Mr. Craft is going to be testifying, in order to orient you, to a portion of Rule 28, particularly A, Subpart 10A through A4, just to get you oriented to the portion of the division's rule and NMOGA's proposed modifications.

ZACHARY CRAFT,

after having been first duly sworn under oath, was questioned and testified as follows:

EXAMINATION

BY MR. RANKIN:

Q. Mr. Craft, have you been sworn in? Did I miss that?

A. Yes, I've been sworn in.

Q. Okay. Mr. Craft, would you please state your full name for the record?

A. Zachary Craft.

Q. And by whom are you employed and in what capacity?

A. I am employed by Enterprise Products Company as legal counsel, and I represent the entire Enterprise Products family.

Q. Do you have in front of you the exhibit book, NMOGA exhibit book, that has Exhibits D through -- or C through M?

A. Yes, I do.

Q. Does Exhibit J1 accurately reflect your current resume?

A. Yes.

Q. Would you just please briefly summarize for the commissioners your background, educational background, and your work experience?

A. Certainly. As you'll see on Exhibit J, page J1, my undergraduate degree is from Emory University, in economics.

I then went to law school, received my juris doctorate in 2009.

I spent approximately seven years working at the law firm Baker Botts, here in Houston, Texas, where I live.

I was in the environmental department of that firm; represented, generally, energy industry

clients, not just upstream and midstream, but certainly including upstream and midstream, really, through any variety of things that related to environmental in some form or another.

And for approximately four years, I have been in-house legal counsel to Enterprise Products. I am primarily the company's environmental health safety lawyer.

Q. And in your role as in-house counsel to Enterprise Products, do your obligations include helping the company identify and correct and report the requirements to the various affiliates and subsidiaries under Enterprise Products?

A. Yes. And in particular, as it relates to environmental, health, safety type regulatory maps.

Q. So you have a good understanding of the corporate structure that Enterprise Products and industry companies employ as part of their normal business operations?

A. Yes.

Q. Mr. Craft, you will be testifying about NMOGA's proposed modifications to the division's rules for venting and flaring in Part 28, as they pertain to -- as it pertains to the reporting requirements applicable to newly-acquired gas

gathering systems and affiliated operators?

A. Yes.

Q. And that particular language in Part 28, Section 10 of Paragraph A3 and A4?

A. Yes.

Q. Now, you prepared a few exhibits that relate to your testimony. And behind Tab J in the exhibit notebook that I referenced, would you just -- as I corrected -- those exhibits you have prepared for today's hearing?

A. That's absolutely correct. I suppose I should clarify these exhibits are screen prints from the US Securities Exchange Commission website. And so they are a list of subsidiaries that have been filed by three companies, including Enterprise Products, with the US Securities Exchange Commission. They are viewable to anyone with internet access at the URLs shown at the bottom of each such exhibit.

But I did provide them for purposes of this hearing.

Q. So which three companies -- midstream companies -- did you pull with their subsidiary lists?

A. The first is Enterprise Products Partners,

LP. That is the publicly traded entity that has the brand known as Enterprise Products, with which our -- who I represent.

The second appearing, starting on page J7, is Targa Resources Partners, LP, also a publicly traded entity of the Targa family.

And then the third, starting at page J9, is Kinder Morgan, Inc.

Q. So in order to kind of explain why we have all of these pages and all of these various entities, would you please give us a little background about how midstream companies -- what their corporate structure is, and about why they have such a corporate structure that they do?

Reference, if you would, the exhibits that you have.

A. Certainly. So to start with, the Enterprise exhibit, pages J2 to J6, the thing that I think stands out from looking at it is, if my counting is right, we disclosed 134 subsidiaries as part of this public filing, which I should mention was made in early 2020.

If you look at the Targa exhibit, starting on page J7, I think I counted 89 subsidiaries that Targa listed.

And then finally Kinder Morgan, if my accounting was accurate, was 334 subsidiaries.

And so I share these as examples, mainly to illustrate that in my view it is common, if not ubiquitous, for large companies, specifically those that are involved in the midstream industry, although I believe in others as well, to operate, even if under a common brand, such as Enterprise or Targa or Kinder Morgan, as a collection of perhaps numerous nominally separate legal entities.

Q. Mr. Craft, what are some of the reasons that midstream operators -- and just to be clear, each of these operators are midstream companies in New Mexico.

Is that correct?

A. Each of the --

Q. I'm sorry. Let me clarify the question. I don't mean everyone was subsidiaries that is listed on the form.

I mean, the parent companies are operators in New Mexico?

A. I mean, these are each large midstream companies with multistate operations. All three have operations in New Mexico, to the best of my knowledge. Enterprise certainly does.

Q. Thank you for clarifying. I just wanted to make that point. Thank you.

Now, what are some of the reasons that -- that midstream companies might have for structuring their -- kind of their corporate structure such as you've outlined here, with numerous subsidiaries?

What are some of the reasons that they would have such a structure?

A. Sure. With the introduction that there are more reasons than I could possibly count, some examples that I think are relevant to what NMOGA would have a say here, is that in most circumstances the parent company and each subsidiary and affiliate can be treated as a separate legal entity.

And because of that, it means that in many cases you can use separate entities to facilitate a commercial transaction.

For example, if you were intending to share the costs and profits from some kind of system, whether it be a midstream gathering system or something else, if you wanted to share that opportunity between two different companies, one way to do it would be to have those two companies create yet a third entity, which is a joint venture between them. They could each own 50 percent of it or it

could be something other than 50/50. Or there could be more than two partners to the joint venture.

But by setting up the desired asset or the desired system as an independent entity, it can be easier to manage than trying to have an asset that is somehow divided without setting up the entities.

And then once you do that, there can also be situations where there may be yet a fourth entity, perhaps an affiliate or subsidiary of one of the first two, that then is contracted to construct and/or operate the new system.

And so by using these different entities, it's possible to make clear between disparate companies what their respective rights, obligations, and duties are as it relates to the project that's being handled by this particular collection of entities.

So that's one type of example.

Another that I think is relevant here is that in some cases the proliferation of entities that you see on these subsidiary lists, and really throughout the industry, a lot of that is also history.

And what I mean by that is that over time there are mergers and acquisitions and things like

that, and there are different types of mergers and acquisitions that can occur, both within midstream and within large companies, generally.

But sometimes when two companies transact, you could have companies that merge and that have -- essentially, two companies become one.

But you could also have a situation where one company buys another company outright; and, therefore, indirectly acquires all the assets that the acquired company owns.

Or you could have a situation where one company directly purchases assets from another company with no change in hands of the company itself.

And as a result of that kind of variety in transactions, sometimes you just end up with -- with layers of entities that have historically existed and that get added to your company's family tree, really, just as a part of processing or achieving some kind of a larger transaction.

So those are a couple of types of examples. There are really a lot more. But I think that the number of different subsidiaries you see in these companies should speak to the commonality with which it occurs.

Q. And so with that background, Mr. Craft, I want to talk a little more about more the division's proposed rules and language and how the language that they are proposing doesn't necessarily work very well with the existing corporate structure of this midstream and NMOGA's proposed resolution.

So I'm going to put up on the screen the NMOCD Exhibit 3A.

MR. RANKIN: And, Mr. Garcia, if I might be -- thank you.

Q. (By Mr. Rankin) Let me know, Mr. Craft, if you're able to see the screen that I'm sharing. I am showing -- it's going to be page 6 of NMOGA Exhibit 3A.

Do you see that on the screen?

A. Yes, sir.

Q. So here is the language under Part A, Section 10, Part A, that addresses the general gas capture requirement.

Can you just review, if you would, for the proposal in particular, that has concerns for NMOGA?

And I'll scroll down, if you will tell me where to go.

A. Certainly. Before you scroll down, a key predicate to the way that the division's drafted

Subsection A works is that the capture requirement applies -- and I quote, to the operator of a natural gas gathering system, end quote.

And the 98 percent, as it's phrased in that first sentence of Subsection 10A, applies in each of two reporting areas, one north and one south of the township 10 north line.

So you have a structure that you're working with where the operator, which is a corporate entity of some kind, has to achieve 98 percent gas capturing, in so many words, in each of two regions.

And it's really the applicability of the capture requirement to the operator within a region that I think drives what I'm intending to testify about.

And so if you look at Paragraph 10A1, that, of course, illustrates how, for each operator region, there is a baseline natural gas capture rate.

And then commensurate with that baseline there is a minimal required annual performance improvement, or increase, in the gas capture rate from 2022 to 2026.

And so I think understanding that each

operator's region has a potentially different compliance track based on the way Subsection A is set up, is that it's a predicate, really, to the changes that NMOGA has requested to subsections -- or excuse me -- Paragraphs 10A3 and also to 10A4.

Q. Go ahead and tell me. Tell us about those two paragraphs, or starting with 10A.

A. Certainly. So looking at 10A3, the division had originally proposed, of course what you see there in stricken text, which was that an operator acquiring a gathering system from another operator shall comply with statewide requirements for the acquired system no later than December 1, 2026, absent approval from the division for something else.

And so NMOGA saw that. We noted a couple of issues with it. There seemed to be a typo in the date, December 1 instead of 31. That -- that's not an issue with the change the division has made.

We also noticed that it was set to refer to a statewide natural gas capture requirement which, you know, wasn't quite consistent with the beginning of A, where there are now two reporting regions, each of which has -- has its own gas capture requirement.

But then what NMOGA had suggested was that in addition to the typos being fixed, that it should be clear that the operator, in demonstrating compliance with capture requirements, really, that the operator should be able to report its gas capture in a manner that is consistent with the compliance that is expected.

And so what we imagined was that if you don't know -- if you don't know how to fold in or portrait separately the newly-acquired system into the operator's preexisting portfolio or not, then you could have a situation where the acquisition of a system would essentially move the goalpost on an operator.

So looking back up at Paragraph A1, you could think of it this way. If an operator begins in the -- what I'll call the 90 to 98 percent bracket, a relatively high-performing operator, and is on a certain compliance track, but that operator acquired a somewhat worse performing system that were, let's say, in the 80 to 89 percent bracket, then unless it were clear that the operator could account for those two systems separately, you would have a C 115B that would really not be clear as to what it was applying to, and that it would seemingly

generate a new compliance track for that operator, based on having acquired a new system.

We didn't assume that to be the division's intent, particularly given that under the way the rule was originally proposed, it would really depend on the form of transaction whether an operator ended up having to incorporate a newly-acquired system or not.

And what I mean by that is that under the way the rule was originally phrased, if one company, say Enterprise, acquired a new system in the name of the same entity that Enterprise had previously registered with the division as an operator, then seemingly all of those assets would be grouped together for purposes of a compliance determination and figuring out what track they are on to get to 98 percent.

But if Enterprise had acquired that new system through a newly-created operating subsidiary specific for that acquisition, then that different structure, hypothetically, would put the newly-acquired system into its own separate baseline, and perhaps give it a slower or a different compliance track under the way the rule is written.

And so as NMOGA, our objective was to really try to suggest a way to make this part of the rule neutral as to the form of acquisition through which the new -- the new system came.

In other words, avoid a setting where the acquisition of a system rewarded or penalized an operator based on how that operator was already structured, in terms of how many subsidiaries were -- different operating subsidiaries, and then also avoid, as a result, penalizing or rewarding an operator for choosing one form of acquisition over another.

Because in our minds, the choice of a stock sale or an asset sale really didn't seem to be particularly germane to the purpose of the rule. It seemed like it was more about making sure 98 percent was achieved.

So we have proposed that the operator should be able to simply create a separate bucket for the new system or not.

The division responded, as you see in -- on the screen, with a little bit different formulation.

What the division has suggested instead, is that any acquisition should get folded into the

operator's -- well, all of the operator's determinations of gas loss for purposes of achieving 98 percent compliance.

And so under that formulation, if an operator acquired a system that performed worse than the operator's preexisting assets, then that could be seen as a penalty, because the operator would have to, essentially, make up for the lesser-expected performance improvement on the acquired system by accelerating whatever activities would otherwise have been necessary to bring it into compliance, or perhaps by finding a way to achieve better than 98 percent capture on the operator's other systems.

It appears that the division recognized that was not a reasonable way to proceed, because the division then added another sentence saying, as you can see, no later than 60 days following the acquisition, the operator may file a written request to the division requesting to modify its gas capture percentage requirements for good cause, based on the acquisition.

I think NMOGA -- we recognized that as a valuable intuition to have. It seems like that was probably meant to address the situation that I was

discussing, where an acquisition acts like a penalty, depending on how it affects the operator's overall gas capture rate.

But the concern that we would have with the formulation the division has proposed now, is really in that last sentence of Paragraph 10A3, which says that the division may preapprove the conditions or deny the request in its sole discretion.

With the caveat that I'm not a New Mexico lawyer, whenever I see the words "in its sole discretion," as you do at the end of that sentence, it is usually in the context that one party wants to have exactly that, sole discretion to act or not act for any reason or no reason on whatever time frame, if any, it believes is convenient or appropriate.

And so as I read that language from the division, it seems concerning that the division would not have some obligation to act in a reasonable, timely, and predictable manner.

It seems strange that the division would propose language suggesting that it need not do so; and, therefore, reserve the right to basically leave the operator in a lurch just because the division, for whatever reason, did not like the idea of

adjusting the operator's capture track to account for the acquisition.

Q. Beyond that issue, Mr. Craft, are there other concerns that NMOGA has regarding the division's ability to make such a determination, in terms of whether it's appropriate or not for affiliates or subsidiaries to be grouped together?

A. I think so. And that starts to bridge us over into Paragraph 10A4.

There was no 10A4 in the original proposal. NMOGA had requested -- and I think this is in NMOGA Exhibit B.

NMOGA had requested that a new 10A4 be added to say that operators that are affiliated may, but are not required to, consolidate their natural gas capture reporting and compliance obligations.

Oh, thank you. Yes, there it is.

Q. Mr. Craft, just to confirm for the record what I'm now showing on the screen, does that reflect NMOGA's Exhibit 3 -- I'm sorry. Is that 3 or --

A. Yes, Mr. Rankin. That's NMOGA Exhibit B, as in boy. And that is the language NMOGA had suggested as 28.10A4.

Q. So explain to us, Mr. Craft, what the

issue is here with -- with the division essentially making the decision about whether operators should be or are -- whether this should be or should not be reported together?

A. Certainly. Well, I should caveat that I don't believe we've received specific feedback from the division on -- on exactly why they made the change they did.

But essentially, the difference between NMOGA's requested A4 and the division's formulation of A4 is that whereas NMOGA says "may," the division's language says "shall."

And so NMOGA offered reasons in our comments, and I believe prehearing statement, on why it would make sense to allow affiliated operators to consolidate their reporting.

But we certainly didn't intend to suggest that all affiliated operators must consolidate their reporting. And I think there's some good reasons why mandatory consolidation of affiliated operators really isn't a good idea.

The first, and maybe the most obvious to consider, is that by requiring affiliated operators to report together that mandatory consolidation, has the possibility to create a violation for an

administrative paperwork reporting issue that is disconnected from what appears to be the substantive goal of the regulation.

And what I mean by that is, if a parent company has two different operators and reports two different operators with separate C 115Bs, that each achieve 98 percent, then under the division's language, which says that affiliate operators shall consolidate their reporting, under the division's language the operator's choice to file two separate reports demonstrating 98 percent would apparently be in violation.

Even though, if my math is correct, there is no possible combination of two affiliated operators, each achieving 98 percent, which combination would not also achieve at least 98 percent. So it would be -- it would create an administrative violation for conduct that seemingly is not hostile to the purpose of the ruling.

I should point out, as well, that it may also be ambiguous in some circumstances whether or not operators are properly affiliated.

One example that could be imagined would be if there were an operator that were jointly owned by two or more companies, one of which were perhaps

also subject to the proposed rule, then there might arise a question as to which parent company is actually obligated to report it.

Perhaps that becomes more confusing still if none of the owners has a majority ownership interest.

Q. That's a situation that you previously -- that's a situation where there may be a situation where a joint venture type situation has arisen and a third -- between two operators, and a third joint venture that's created as an operator in the gathering system.

Is that the situation that you're talking about there?

A. Do you mind repeating that, please?

Q. Sorry. You were talking about a situation where there may -- two parties may have created a joint venture, previously in your testimony.

Is this the situation you were referring to, where there may be two operators or two entities have created a third entity to operate a gathering system, the question then arises who -- who actually is the party to be reporting in that instance?

A. Yes. Thank you for repeating that.

That's correct.

Q. Sorry. I didn't mean to interrupt. I just wanted to make sure I understood the reference and your prior testimony.

A. So, Mr. Rankin, I had one other, I think practical point I wanted to acknowledge on -- on why NMOGA is opposed to mandatory consolidation of affiliated operators, if this is a good time.

Q. Sure.

A. I think the other practical problem that perhaps wasn't evident to the division, but that comes to mind for me as a company lawyer, is that requiring consolidated reporting for the division, it does create an additional complexity in how the affiliated operators would allocate compliance costs between them, particularly if those affiliated operators have different baseline gas capture rates.

That may not always matter, if you're dealing with wholly-owned subsidiaries.

But it can have practical consequences if, perhaps, one entity has a different tax structure than the other, or for some reason those costs are being passed on to a third party.

So things like that could be reasons for nominally affiliated operators to consider accounting and complying separately, frankly,

regardless of whether they would have met the 98 percent capture requirement on a combined basis.

And so I guess I would boil all of that down to say I'm not certain, and am not familiar with why the division changed "may" to "shall."

But I think from NMOGA's viewpoint, that A4 language there, if "shall" becomes "may," then the concerns go away.

Q. So just as -- if I might just -- and correct me if I am wrong, but I want to be sure I understood. The gist here is, essentially, that NMOGA's proposed language here isn't opposing the structure or framework on preexisting corporate structures that exist in this hemisphere. It doesn't necessarily work very well with that existing corporate structure.

Is that right?

MR. AMES: Objection, leading question.

Q (By Mr. Rankin) I'm just trying to summarize. That's fine.

MR. AMES: Yes, exactly. Leading question.

HEARING OFFICER ORTH: Yes, Mr. Rankin.

MR. RANKIN: That's fine. I don't want Mr. Ames to be upset about it. So I don't want -- I

just wanted to make sure I understood the gist of Mr. Craft's testimony. So --

MR. AMES: I'm not upset about it, Mr. Rankin. It's important to comply with the rules.

MR. RANKIN: That's fine.

Q. (By Mr. Rankin) Mr. Craft, I think that the key takeaway, if I understand it, is that your point about whether or not there is more than one bucket, compliance bucket that the operator is trying to meet, would be met whether it's multiple buckets or one big bucket, because the requirement -- compliance requirement is still 98 percent.

Is that -- is that what you're saying?

A. Yes, it is.

Q. That's all I wanted to get to.

Thank you very much.

I think, Mr. Craft, is there anything else? I think -- are there any other points or issues that we want to discuss, in terms of NMOGA's requested modifications to these two provisions?

A. You know, I did want them to know, Mr. Rankin, that I've seen the Climate Advocates' requested language in the A3 and A4 -- or it may

have just been A3 -- and I believe NMOGA opposes that language.

But that, I think, should be inherent in the language that I've testified is appropriate for A3 and A4.

Q. Let's see. Is this the language?

A. Yes. That looks to be the Climate Advocates' language.

Q. Okay. So you prefer, obviously, NMOGA's language over what the Climate Advocates' language is?

A. I do. Would you like me to describe why?

Q. Sure.

A. I think the concern we had with Climate Advocates' proposed formulation was probably twofold.

First, it -- it creates a conflict with the operator-based reporting and compliance framework that is inherent to Section 10A.

And what I mean by that is, Climate Advocates' language suggests that there was a gas capture requirement that applied to the acquired system.

And because the gas capture requirement is determined on the basis of an operator and a

reporting region, there's not necessarily a gas capture requirement for a gathering system.

So the -- the reference, essentially, is to a thing that doesn't exist.

It wasn't harmonious with the unit of reporting and compliance that was in the proposal framework, and so there's not really a way that one could apply that.

I think the other, you know, issue we had as well, was that it seemed like the Climate Advocates were making an assumption that, you know, 98 percent capture is required on every single piece of equipment. That really seemed to be where they were going with the explanation in their prehearing statement on this language that's on the screen.

And I think NMOGA's position is that, you know, 98 percent is 98 percent. And if we can get that more efficiently in some areas than others, then if the goal is 98 percent, let's focus on that and focus less on, you know, slicing and dicing systems in a way that make it a needlessly complex emergency.

Q. Very good.

Mr. Craft, I think -- I don't think I have any other questions.

Are there any other responses to Climate Advocates' proposed modifications that you want to raise with the commission at this time?

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

Q. Mr. Craft, were Exhibits J1 through J17 prepared by you or under your direct supervision?

A. Yes, they were.

MR. RANKIN: At this time, Madam Hearing Officer, I would move the admission of Exhibits J1 through J17.

HEARING OFFICER ORTH: All right.

Let me pause for a moment to ask if there are objections to NMOGA Exhibits J1 through J17.

I hear no objections.

J1 through J17 are admitted.

(Exhibit admitted, J1 - J17.)

MR. RANKIN: Madam Hearing Officer, I have no further questions at this time of Mr. Craft, and pass the witness for questioning by others.

HEARING OFFICER ORTH: Thank you very much, Mr. Rankin.

Mr. Ames, do you have questions of Mr. Craft based on his testimony?

MR. AMES: No, I think not. Thank you.

HEARING OFFICER ORTH: Thank you.

Mr. Biernoff, do you have questions of Mr. Craft?

MR. BIERNOFF: Madam Hearing Officer, I don't have any questions of Mr. Craft.

HEARING OFFICER ORTH: Thank you very much.

Ms. Fox, do you have questions for Mr. Craft?

I'm sorry. Was that Mr. Baake saying that he was going to conduct the questioning?

MR. BAAKE: I don't think either one of us have questions. I was just going to defer to Tannis, if she has any questions.

I don't have any questions, no.

HEARING OFFICER ORTH: All right. Thank you.

Just clarifying, just confirming, Ms. Fox, you don't have questions either?

MS. FOX: That's correct. Thank you, Madam Hearing Officer.

HEARING OFFICER ORTH: Okay. Thank you.

And, Ms. Paranhos?

MS. PARANHOS: Thank you, Madam Hearing Officer. I have no questions for this witness.

HEARING OFFICER ORTH: All right.

Commissioner Engler?

COMMISSIONER ENGLER: I have no questions. Thank you.

HEARING OFFICER ORTH: Madam Chair?

CHAIRWOMAN SANDOVAL: Oh, you know I do. Not too many, though.

EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. Mr. Craft, thank you.

First off, I'll start with my really exciting questions here.

Do you support the rule?

A. Madam Chair, I have really been involved in a narrow portion of the rule. I think I would need to defer to others to state NMOGA's position on it.

Q. Okay. Do you, in your experience with either ruling, that you would defer to others, do you feel like it was a cooperative process?

A. A similar answer, Madam Chair. I've been involved in a relatively narrow portion of the rule. And if there were collaborative discussions, I have not been a party to them personally.

Q. Okay. The first couple of questions on the -- okay.

Are you familiar with the process that EPA uses for greenhouse gas reporting and how to manage all of these company subsidiaries?

A. No, ma'am. Not off the top of my head.

Q. Okay. Subchapter C, Part 98, Subpart A, that -- the rule, it requires, basically, everything to be reported under the highest level US parent company of the owners, in parentheses, or operators, of the facility or supplier and a percentage of the ownership interest for each listed parent company as of December 31 of each year for which data are being reported according to the following -- and then it goes into all of this additional detail of how you do it. It gets complicated.

It reads -- so you're not familiar with that? That's not something that you get involved with in your company?

A. If I've been asked to comment on a greenhouse gas inventory, in regards to a subsidiary or joint venture that was less than 100 percent, it's not coming to the top of my mind.

But I'm also not sure I heard your words precisely. Was there a section of Part 98 Subpart A I should be looking at?

Q. It is -- oh, gosh, I'm going to have to

scroll back up.

I just searched for the word "parent," and it's the second time parent company -- or the first time parent company comes up within there.

It's under 98.3, which is one of the general monitoring reporting record and verification or requirements.

3C11, and that gives -- it's just -- it's the infor- -- or the wording on how you report up through that parent company.

So ultimately, though, you're not familiar with that?

A. It's been a while since I've looked at it, Madam Chair. I see that that provision, which is 40 CFR Section 98.3 appears to be describing a facility level greenhouse gas report.

And so I -- I suppose I would point out that an obligation to disclose the parent company or companies of the facility, I would suggest that that is different from a parent company level reporting scheme.

Q. Well, but don't you report for midstream -- for gathering and boosting, you report that on a basin level, which could comprise more than one facility, correct?

A. I'm sorry, Madam Chair. I don't recall, based on the reporting under Part 98 for gathering systems. I would have to check that.

Q. Okay. Gathering and boosting -- okay. Let me...

So it sounds like -- how would you propose to minimize confusion in reporting, or I think circumvention of potentially the gas capture percentage, if there was sort of an open option as to how you want to group facilities?

A. I'm not sure I know what you mean by circumvention.

The reason I say that is that to my understanding, if a parent company overall is, in fact, achieving 98 percent, then from -- I'm sorry. I said that in reverse.

If -- if all of the subsidiaries and affiliates of a common parent are each reporting 98 percent or better, my mathematical understanding is that any combination of those subsidiaries and affiliates would also generate a calculated 98 percent figure.

In other words, I don't think it's a circumvention to take a large parent company and split it into multiple pieces.

I think all NMOGA is suggesting is that it would be an appropriate flexibility to allow, when a company finds it desirable.

Q. Do you not think there's potentially a way that facilities may be able to report performing facilities -- I think you termed it -- could be grouped together with maybe a high performing facility to even themselves out, in a way?

A. I believe, Madam Chair, under the division's proposed rule, if a single operator had two systems in one reporting area, then that operator would take the average of those two systems to determine -- or the combined weighted average, I guess, of those two systems -- to determine whether it achieved 98 percent.

And so if you're asking could an operator with multiple systems have one system at 97 and another at 99 and still comply, I believe the division has proposed a rule that would allow that flexibility.

Q. Okay. But the wording would have to be changed from "shall" to "may"?

A. NMOGA is requesting that it be changed from "shall" to "may."

But I think I may have misunderstood the

predicate to your last question.

Q. In order to make that happen, would in -- whatever -- 19.15.28.10A4 -- does that need to be changed from "shall" to "may"?

A. In order to make what happen?

Q. In order to make -- I think what you just said previously worked.

In order to make this -- in order to make the rule function, as you think it needs to function in order to accommodate for all of these various operating scenarios which look complex, does that function of the rule, along with all of these different operating scenarios, does it have to be changed from "may" to "shall" to make that work?

I'm sorry. "Shall" to "may"?

A. Madam Chair, I think there were two subjects that I've talked about.

Certainly from NMOGA's perspective in 28.10A4, the division's proposed language, if it changes from "shall" to "may," then that would address the concern that I've attempted to articulate on behalf of NMOGA.

In terms of your question, Madam Chair, about whether an operator's -- whether an operator would be able to aggregate multiple systems, some of

which perform better than others, that -- that possibility appears to be present the way that the division has always drafted the rule.

Q. Okay. Would there be, though, potentially broader ramifications if a company were to report under -- gosh, I hope not three pages -- maybe three pages of different subsidiaries here, on -- on things that such as -- and I don't have a citation off the top my head.

But such as the GIS mapping requirements for pipelines or these natural gas management plans?

I mean, isn't -- isn't that going to impact every piece of this rule, not just this little component?

Does that make sense?

A. It does. I mean I'm trying to think through how to answer that, Madam Chair.

I believe, as NMOGA has phrased it, the wording here in 28.10A is really just about the gas capture reporting and compliance.

And so I suppose if there were another feature of the rule that imposed a separate mandate, whether at the operator level or otherwise, then -- you know, perhaps that section could be evaluated for whether affiliated operator aggregation is

valuable or not.

I suspect NMOGA would prefer an option, but not an obligation, to consolidate affiliated operators. But I don't believe that hypothetical has been presented to us until, really, just now.

Q. Okay. Do you see where it might be more useful for the division, for example, to have an entire gathering with the map of Enterprise, as opposed to, I don't know, three different pages of Enterprises? A consolidated map, if you will?

A. I'm not certain what value that would provide the division.

Q. Can you see the benefit of having a map with the entire system on it and not pieces, having to put those pieces together?

A. I'm not sure what that would be intended to accomplish, Madam Chair. No, I don't.

I can see that, as the Enterprise corporate family, we need to be aware of all of our assets. I'm not sure why it would be important, as long as it's clear that each piece is achieving 98 percent. I'm not sure how it would be so important for the division to be able to see how they would fit together.

Q. Okay. Are you -- are you familiar with

OCD's inactive well rule?

A. No, I don't believe I am.

Q. I don't have the citation up. But basically, an operator -- a production operator, which I can understand you don't own production wells, has -- you can only have X many wells that are over the limit -- or I'm sorry -- that are not operating, and if you're over that limit, that might impact your ability to get permits.

So if you have a thousand wells, I think you could have ten inactive wells.

So if that's what the rule is, could you see where, potentially, an operator -- say a larger operator is buying a smaller operator -- and don't worry, this is my last question, so we should meet the 6:00 time frame.

Could you see where, if a larger operator is maybe buying a smaller operator, or another operator that could push them over their inactive well limit, and maybe they would have, now, 15 wells instead of the 10, because they just acquired 5 new out-of-service wells.

Could you see that scenario?

A. Madam Chair, with the caveat that Enterprise does not have upstream assets, and that

I'm not personally familiar with that rule, I think what you're saying, if a company has 8 and buys 7 more, it will have 15.

Q. Yes. And then be, like -- you know, out of compliance with that rule.

I guess would you -- and -- and you know, I think you said you were concerned with the language that says -- hold on -- basically, gives the division flexibility. The division may approve or deny the request in its sole discretion, which is in the language in 10A3, and you had concern about that discretion.

I guess, could you potentially see some similarities between how the OCD would handle inactive wells when an operator gets out of compliance because they acquired a new system, with how the OCD might manage an operator acquisition here? You're putting them again out of compliance because they were now, instead of over the active well limit, over their -- or but under their gas capture percentage?

Could you see how maybe that would be an onus?

A. I would certainly think that that would be a reasonable basis for the division to grant --

"variance" isn't the right term -- but some kind of a different dispensation, as is suggested.

I think, however, Madam Chair, the phrase "in its sole discretion," to me, has the effect of suggesting that the division really isn't obligated to behave reasonably, rationally, or timely, and suggest a disclaimer of the need, you know, to consider circumstances reasonably, the way that you just outlined.

Q. Maybe this is a dumb question.

But doesn't the division have within its discretion to do most things, regardless if it's written on paper?

A. Well, again, the caveat that I'm not a New Mexico lawyer, and believe most US jurisdiction administrative agencies have obligations under their organic statutes and case law to act in a manner that is consistent with the law that is not arbitrary and capricious -- those being legal terms of art -- and otherwise, in a certain fashion.

And that fashion normally is not an agency behaving, as its staff determined to do on their own, outside of defined process or criteria.

And the term "sole discretion," to me, says that the division essentially can do whatever

it wants for any reason, or no reason, unbound by the relevant legal criteria.

Q. So would a potential solution be just to get rid of, basically, "in its sole discretion," so it would read the division may approve -- approve a condition or deny the request, and just end it there?

A. That would certainly be an improvement, Madam Chair. I think I would suggest, though, that it -- it seems like the way the division has set up A3 is creating, potentially, a lot of process for very little value, in the context of an acquisition.

And it -- because of the way that each operator; and, therefore, each collection of systems has to get to 98 percent by 2026, it seems to me that whatever different compliance track the division might consider and perhaps approve or not for an acquired system would really only apply for the transition period between 2022 and 2026.

And so rather than go through the exercise of potentially having each acquisition of a lower-performing system subject to this kind of a case-by-case review by the division, it seems more reasonable to simply allow the operator to create a separate bucket for the acquired system that has its

own track under A1, or to group the acquired system in with its preexisting portfolio of assets.

And so that was the intent of NMOGA's suggested language for A3.

And I can read that into the record, if that would be helpful.

Q. I mean, I think it's already in the record. It's been entered in with the exhibit.

But -- okay. That's fine.

CHAIRWOMAN SANDOVAL: That's all I have.

HEARING OFFICER ORTH: Thank you, Madam Chair.

Is there any reason not to excuse Mr. Craft?

MR. RANKIN: I have no further redirect for Mr. Craft. So no reason for us not to suggest his excusal.

HEARING OFFICER ORTH: Thank you very much, Mr. Craft. You're excused. Thank you for your testimony.

Let's reconvene in the morning at 8:00 a.m.

Thank you all very much.

(Proceedings concluded at 6:04 p.m.)

CERTIFICATE

I, Paul Baca, RPR, CCR in and for the State of New Mexico, do hereby certify that the above and foregoing contains a true and correct record, produced to the best of my ability via machine shorthand and computer-aided transcription, of the proceedings had in this matter.

/s/ Paul Baca
_____
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