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 3 A.M. SESSION

January 6, 2021

8:30 a.m.

Hearing Officer Felicia Orth

Chairwoman Sandoval

Commissioner Engler

Commissioner Kessler

REPORTED BY: PAUL BACA, CCR #112
PAUL BACA COURT REPORTERS
500 4th Street, NW, Suite 105
Albuquerque, New Mexico 87102

Attorneys Present:
Eric Ames EMNRD
Michael Feldewert NMOGA
Adam Rankin NMOGA
Ari Biernoff Commission of Public Lands and others
Tannis Fox Climate Advocates and others
Elizabeth Paranhos Environmental Defense Fund
Chris Moander AG Office
David Baake AG Office
Also Present:
Dylan Rose-Coss Tech Support
John Garcia Tech Support
Florene Davidson OCC Support

I N D E X

HEARING OFFICER ORTH: Good morning, everyone.

My name is Felicia Orth. I am the hearing officer appointed by the Oil Conservation Division to conduct a hearing in this matter of the application of New Mexico Oil Conservation Division to consider proposed rules to regulate the venting and flaring of natural gas from oil and natural gas production and gathering facilities.

The case was docketed as Case Number 21528.

You will find all documents related to this matter on the public outreach and engagement page of the Oil Conservation Division.

We are in, this morning, one of our many opportunities for public comment. We ask that you keep your comments to two minutes. So we'll break in at some point to ask you to wrap up if you go beyond that.

You may be expelled in the event you attempt to disrupt the hearing.

And there may be a question for you from a commissioner or a party after you speak.

We have two commissioners with us this morning.

Madam Chair is Adrienne Sandoval.

And then we have Commissioner Jordan Kessler on the line as well.

I will call you in this order. Bill Midcap, Ward McCartney, Stefi Weisburd, Idolia Hawkins, and David Begay. Those are the ones I have on the list for this morning.

In the event you have a friend who would also like to sign up, that would -- the friend would follow the instructions on the OCD outreach web page, e-mailing Florene Davidson.

You can also submit written public comment of any length to Ms. Davidson.

So let's start with Bill Midcap.

MR. MIDCAP: Good morning.

Can you hear me okay?

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

MR. MIDCAP: Yes. My name is Bill Midcap. I live in Santa Fe, New Mexico. I want to take this opportunity to thank you to provide comments to the Oil Conservation Commission.

I'm a retired farmer and rancher. And just like all farmers and ranchers, we're passionate about the environment.

I currently work for Rocky Mountain Farmers Union as a senior policy adviser. We represent family farmers and ranchers. We have over 20,000 members in Wyoming, Colorado, and New Mexico. The Rocky Mountain Farmers Union is a progressive grassroots organization funded in 1907, dedicated to serving our rural communities for stewardship in the use of natural resources and the perfection of a safe and secure food supply.

We all know that methane is a strong greenhouse gas that is responsible for 25 percent of the climate change we are already experiencing today.

You've heard all the numbers, and I'm not going to go into that. But put methane in a pipeline and put it to use. New Mexico could really benefit from the added revenue that funds our police departments, fires -- fires, schools, roads, and so many other things that benefit our citizens of New Mexico.

Global warming has already cost ag producers millions of dollars that can never be recovered. Severe storms and droughts related to climate change have farmers and ranchers guessing about their future.

As temperatures increase, producers are experiencing declining yields and declining quality in the food they supply to consumers in America and all over the world.

Climate change is expected to have a major effect on most crops and livestock.

As temperatures increase, crop production shifts to follow temperature range for ultimate growth and yield. But production at any given location will be more influenced by the availability of adequate moisture in growing seasons.

Today producers are spending over $15 billion a year on pesticides to control weeds and insects. Those costs are expected to rise with the increased temperatures and emissions due to climate change.

Climate change is also influencing livestock production. Livestock damage and damaged performance, production, fertility, and limits production of milk and eggs.

The effects of climate change also need to be considered along with other evolving factors that impact adding production, such as changing in farming practices and technology.

Crops grown in the United States are

critical for the food supply here and around the world.

Changes in temperature, atmospheric carbon dioxide, and the frequency and intensity of extreme weather could have significant impacts on crop yields.

Emissions from methane are costing the American taxpayer about $2 billion a year. And reducing methane from the oil and gas sector has a very low cost.

We are in strong support of Governor Michelle Lujan's call for leading -- nation-leading methane rules. And to achieve that goal, the Oil Conservation Commission must strengthen the oil and gas commission's proposed methane waste rule to eliminate methane waste.

The final rule must achieve three goals:

Ban routine flaring and require oil and gas companies to capture 98 percent of methane emissions.

Strengthen state reporting and public notice requirements, to improve transparency of all oil and gas operations.

The oil and gas commission should approve this proposal put forward by requiring green

completions to minimize methane emissions during completions and recompletions.

Methane provisions to ensure clear state rules preventing methane from being vented into the atmosphere.

HEARING OFFICER ORTH: Could you wrap up, please?

MR. MIDCAP: Okay. Nearly 70 percent of all oil and gas methane pollution in New Mexico occurs through leaks. So it's critical that the New Mexico environment department adopt the rules that holds polluters accountable.

Thank you very much.

HEARING OFFICER ORTH: Thank you very much, Mr. Midcap.

Ward McCartney.

MR. McCARTNEY: I am Ward McCartney, at 350 New Mexico, and I'm from Belen, New Mexico.

Thank you for your time to listen to us.

The reason I wanted to speak to you is my only grandchild, a son, turned one year old last week, and I want him to have a future. The fossil fuel industry was known, as a global warming, existed 30 years ago, but they are the problem.

Instead of developing clean, renewable

energy they have, instead, spent hundreds of millions of dollars to delay the world switching over to renewable energy.

Renewable sun and wind energy last year produced more electrical energy than coal-fired power plants, and wind and solar didn't clean our air.

Recently, we found out that the oil and gas industry was wasting twice as much methane gas as the self-regulated oil and gas industry has reported.

In my opinion, the fossil fuel industry has lost all credibility. And quite frankly, executives should be facing jail time.

So yes, it's obvious that oil and gas needs to be strongly regulated.

A parting thought.

I challenge the oil and gas lobbyists to park their gas-burning SUV in their garage with the windows rolled down and the garage door closed for 15 minutes.

I'll do the same with my solar-powered -- panel-powered Chevy EV Bolt. We'll see who walks out of the garage.

Like I said, it's my grandson's future.

Thank you.

HEARING OFFICER ORTH: Thank you, Mr. McCartney.

Stefi Weisburd.

MS. WEISBURD: Thank you to the commission for its hard work and for allowing me to express my support for the strongest possible methane rules, as recommended by the coalition represented by the Western Environmental Law Center.

The recent studies reveal unprecedented methane leakage in the Permian compared to other parts of the nation. We simply cannot rely on the industry to responsibly monitor and steward our resources by themselves.

My name is Stefi Weisburd. I live in Tijeras, where my water and my well fell 20 feet in three years. Three of my neighbors had to drill new wells this year. And many people living south of me have to truck in all of their water.

The Southwest is now in the 19th year of the second worst drought in a millennium.

Recent press articles have warned us of the return of dust bowl conditions, and shown how ranchers in De Baca and Chaves Counties have had to sell off much of their -- this year.

I've talked to farmers, owners of rafting companies, and ski managers, and they are all extremely worried.

What makes this drought so bad? Greenhouse gas emissions have driven what might have been a short, moderate event into a mega drought.

And where do the emissions come from? Right here. Per capita, we emit at least 50 tons of CO2 equivalent each year, compared to the national average of 18.

We are letting one industry decimate others at a time when we desperately need to diversify.

Yes, the largely out-of-state oil and gas industry has provided jobs and significant tax revenues. But the global energy landscape is profoundly changing towards a carbon-neutral world by 2050.

What will New Mexico look like then, when the demand for oil has plunged? Will there be enough snow and rain for our farmers, ranchers, and outdoor industries? Or will New Mexico still be in drought with nothing left for our children but dust and acres of abandoned wells.

Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Weisburd.

Idolia Hawkins is next.

(Discussion off the record.)

HEARING OFFICER ORTH: Idolia Hawkins?

David Begay?

If Idolia Hawkins or David Begay are on the line, please speak up.

All call-in callers have been unmuted.

All right. In the event Idolia Hawkins or David Begay join us for a subsequent public comment session, I will accept their comment at that time.

If you know them, please let them know that.

(Discussion off the record.)

HEARING OFFICER ORTH: I do see Gabriel Vazquez for an 8:30 session tomorrow morning, but I'm happy to accept his comment at this time if he's on the line.

Mr. Vazquez?

MR. VASQUEZ: Yes. Thank you, Madam Chair, Commissioner Kessler, and other panelists today. I apologize for any confusion. I had a confirmation for this morning.

We are -- I'm a City Councilor here in

Las Cruces. I've spent my career -- I've worked hard to improve the condition of my people here in southern New Mexico.

One thing that's been consistent with my time serving in office is that we are the poorest state in the nation. Yet, out-of-state oil and gas companies and their shareholders have continued to reap enormous benefits from our natural resources.

While our children continue to suffer from the educational outcomes, from record hunger, to some of the highest poverty -- child poverty rates in the nation, oil companies continue to look to New Mexico as a cash cow and as a way to finance their next luxury home or Wall Street investment. That is not fair to me.

And the royalties that we get to help fund our schools and hospitals absolutely are a huge asset to this state. But is it nearly enough for what these companies are making in profit? I don't think so.

To make matters worse, these companies pollute our environment, accelerate climate change, create sinkholes in our communities, they poison our air, they get rich from our state, and many don't clean up their wells or bother to capture enough of

the methane that they produce, leaving valuable taxpayer dollars on the table.

This is absolutely an environmental --

The OCC must be required --

HEARING OFFICER ORTH: I'm sorry. You cut out there briefly.

After the word "environmental," will you pick up there, please?

MR. VASQUEZ: Yes.

This is absolutely an environmental injustice and a racial injustice issue, and I think it should be rectified.

The OCC should ban routine venting and flaring. It should require all producers to capture at least 98 percent of methane emissions, and it must strengthen its public notice requirements to communities when threats to their health arise.

And I believe that that's the bare minimum.

I think that New Mexico should stop settling for what it can get, and it should demand what it deserves.

Let's protect the health and the environment of our communities, and particularly our communities of color. And let's, at the very

minimum, demand our fair share of dollars while this industry continues and will continue to profit enormously from our land and our natural resources.

It is my opinion that this rule must be strengthened. What we have now is a good start.

I'm sure you've heard the recommendations of many other speakers about what could be done to really maximize the return on investment while, at the same time, acknowledging that we must begin to transition away from this industry, and we must mitigate the impacts -- the health impacts to our communities, especially for those communities of color who live adjacent to and work at these facilities.

Thank you, Madam Speaker, Madam Chair, Commissioner Kessler, and other panelists here.

HEARING OFFICER ORTH: Thank you very much, Mr. Vazquez.

All right. We have now come to the end of the public commenters for this morning. There are many other opportunities every day of this hearing between now and January 15.

We will return, at this point, to the technical case.

When we broke in the technical case at

5:00 yesterday, Mr. Ames was in the middle of questioning Mr. Lepore.

I see Mr. Ames, and I had seen Mr. Lepore -- let's see here.

Do we have everyone we need?

Let's -- based on some of what happened yesterday with the sound, although I know all of the technical parties entered their appearances yesterday, let's do just a brief sound check and appearance check, if you will, this morning before we begin, now that I think of it.

I will start with the lawyers in the attorney general's office who represent the commission.

Mr. Moander, I know you are on.

Let's see. I had seen Mr. Moander.

If you'd like to introduce yourself you can, or Ms. Malave.

No?

So, Mr. Ames?

CHAIRWOMAN SANDOVAL: I don't believe she's going to be joining us today. Oh, it's Mr. Moander.

HEARING OFFICER ORTH: Okay. Thank you. I had seen him.

Mr. Ames, if you would, let's have your appearance and check your sound.

MR. AMES: Good morning, Madam Hearing Officer, Madam Chair, and members of the commission.

Eric Ames, counsel for OCD.

HEARING OFFICER ORTH: Sounds great. Thank you.

Mr. Feldewert?

MR. FELDEWERT: Good morning, Madam Hearing Examiner, Madam Chairman, commission.

I appreciate your reminder to test your sound, because I realized after you said that, I had not -- I had to reset my computer each time. So I appreciate that.

As a result, I'm here. It sounds like you can hear me. It's Michael Feldewert with the Santa Fe office of Holland and Hart, here on behalf of NMOGA, along with my partner, Adam Rankin.

HEARING OFFICER ORTH: Thank you very much, Mr. Feldewert.

Mr. Biernoff?

MR. BIERNOFF: Good morning, Madam Hearing Officer. Good morning, commissioners, counsel, and witnesses.

I don't know if it's just me, but when

Mr. Feldewert was speaking it sounded a little faint. I just wanted to mention that in case other people heard that too.

HEARING OFFICER ORTH: All right. Thank you for that. He was a little softer than, for example, your voice is right now, or even Mr. Ames.

Let's go back to Mr. Feldewert for a moment and see if he can't increase his volume just a little bit.

MR. FELDEWERT: I am back on.

Is this better?

HEARING OFFICER ORTH: That is better, yes. Thank you.

MR. FELDEWERT: I appreciate that, Mr. Biernoff. Thank you for pointing it out.

HEARING OFFICER ORTH: Thank you.

Ms. Fox?

MS. FOX: I'm here today. I'll let Mr. Baake introduce himself, to make sure his sound and video are working.

Good morning, commissioners and Madam Hearing Officer and counsel.

MR. BAAKE: Good morning.

HEARING OFFICER ORTH: And, Ms. Paranhos?

MS. PARANHOS: Good morning. Elizabeth

Paranhos, on behalf of the Environmental Defense Fund.

HEARING OFFICER ORTH: Thank you.

All right. So now, if there are no preliminary matters, we can return to Mr. Ames' and Mr. Lepore's presentation.

Thank you both.

MR. AMES: Thank you, Madam Hearing Officer.

MATTHEW LEPORE,

after having been previously first duly sworn under oath, was questioned and continued testifying as follows:

CONTINUED EXAMINATION

BY MR. AMES:

Q. Matt, when we left off yesterday you were about to discuss the definition of emergency.

Before we pick up that thread, I would like to step back to some definitions you mentioned earlier, the definitions of average daily well production and average daily facility productions.

And at the time you testified, both definitions you indicated that the OCD was proposing a few changes to the version of the definitions that appear in OCD Exhibit 4A, our revised PowerPoint

presentation.

Do you have an exhibit -- or do you have a document that we could show the commission that illustrates more clearly the changes that OCD is proposing to make?

A. Yes, Mr. Ames. We have prepared a document that shows the changes that were made yesterday morning, after we had prepared Exhibit 4A. So I believe Mr. Powell is prepared to share the screen and show those two definitions and the rules that they are implicated by.

Q. Thank you.

MR. AMES: Brandon, can you please share that for the commission?

Thank you.

Can you make it a little bit bigger, perhaps?

That's great. Excellent.

Q. (By Mr. Ames) So that -- please take it away.

A. Okay. Again, so good morning, Madam Chair, commissioners, Madam Hearing Officer. Matt Lepore with Insight Energy Law.

So I did talk yesterday about these two definitions, but we didn't have, as I said, the

language that was inserted yesterday.

So here we show that language and we have highlighted the changes.

For average daily well production we simply inserted the word "natural" in front of the word "gas."

We have tried consistently to use the term natural gas. And it was pointed out that we had failed to do so in that definition yesterday.

For average daily facility production there were slightly more substantive changes. You can see we struck "authorized by the division to commingle oil and gas" after, again, further conversation with stakeholders determining that that really wasn't a necessary clause, did not clarify -- did not add anything to what we were trying to accomplish.

So instead, we have a facility receiving production for two or more wells struck at the surface, added natural gas again twice.

So not major changes from what you saw yesterday, but meaningful changes, from our perspective.

If I could, I think it's worth spending a minute here to say, you know, both why we're

concerned with getting this right and the places where this definition comes into play.

So it comes into play -- and, Mr. Powell, maybe you can scroll down now because I think we show the three rules.

Without getting into real detail, there are three places where this comes into play.

It comes into play with respect to how frequently an operator might have to do an AVO inspection, whether that occurs on a weekly basis or a monthly basis.

It comes into play with the installation of an updated flare stack, a flare stack that's equipped with an auto ignitor or continuous pilot. There's a trigger there that this -- this is relevant to.

And it comes into play with respect to when an operator might have to put metering equipment or measuring equipment on a flow line.

Where it doesn't come into play is with respect to the prohibition on routine flaring of natural gas or on the natural gas capture requirement, 98 percent. It is irrelevant to those two things.

Now, Brandon, if you don't mind going back

to the top.

How does this work? I think that's the other thing that's important for everybody to try to understand at this point, what the division was trying to accomplish.

If we look at a single well, it's pretty straightforward. A single well that has its own production equipment, such as a separator, perhaps a storage tank, or perhaps a flare.

If that well is seeing this low volume of production, that's what the flare will see. That's what the separator will see. And that's the place where we have given a different standard in a couple of the three places I just described.

That math gets a little more complicated if you have multiple wells feeding a single stack, a single facility. That's what the average daily facility production calculation intended to address.

So in this scenario, if you have three wells each producing 50,000 cubic feet per day on average, individually those wells are low-producing wells, are commonly called stripper wells.

But if you put all three of them together and they are all going through this same facility, we look at it from the perspective of the facility.

The facility is now seeing 150,000 cubic feet per day on average. That's not low production.

In those cases, we didn't want these exceptions to apply, so we want those treated as if they were not stripper wells. Even though individually they are, the facility is not.

And that's what we believe these definitions accomplish. That's the division's intent, is that a facility of the kind I just described would be treated as a -- as a not low producing, as not a stripper well. So...

Q. (By Mr. Ames) Thank you, Mr. Lepore.

Are you saying, then, that the net effect of the new definitions, particularly the definition "average daily facility production" is to extend the flaring of the meter requirements to more stripper wells?

A. Yes, Mr. Ames. I think that's a fair characterization. As provided, those stripper wells were being serviced by a single facility. That facility would be covered by the more stringent AVO and metering requirements and flare replacement requirements.

Q. Is it your understanding that the New Mexico Oil and Gas Association is -- is okay

with these changes?

A. It is. And I apologize if you -- my dog is -- has something to say about all of this briefly.

That is correct, Mr. Ames. You and other members of the division staff have been engaged quite actively with representatives from NMOGA, including Mr. Feldewert, over the last several days hammering out this language. And my understanding is that this is agreed-upon language.

Q. So, Mr. Lepore, my understanding is that the division agreed, though, to remove the references in the definition to crude oil production of 10 barrels per day.

Why did the division do that, but retained the reference to the 60,000 standard cubic feet of gas in the division down below?

MR. AMES: Brandon, if you could scroll down again so we can show those changes.

Q. (By Mr. Ames) Why did we make that change, as you understand it?

A. Thanks for the question, Eric.

So yes, we had originally -- if -- where we started was looking at the sort of stripper well definition that is part of the tax -- the tax

regulations for severance tax purposes. That definition references both a gas -- a natural gas threshold, the 60,000 cubic feet, and an oil threshold of 10 barrels of oil.

This rule is focused on natural gas and the venting and flaring of natural gas. So it seemed reasonable and logical to us to focus these -- these definitions and these conditions on gas wells or -- oil wells would still be captured, assuming that they were producing the volume of natural gas referenced here, the 60,000 cubic feet.

So oil wells don't get a free pass. But by themselves, that 10-barrel oil threshold did not seem to be an appropriate trigger, and that's why we agreed to do that.

Q. Great. Thank you.

So I just want to go back to another question that I asked you, and maybe get some clarification.

I asked you whether these changes to the definitions, particularly the change to the definition of average daily facility production, would result in more stripper wells being subject to the AVO flare and metering requirements.

And I think you said yes. To the extent

they are part of the larger facility, they would be subject to those requirements.

Does anything in these definitions, or the provisions that use those definitions, change the status of the stripper well from a tax perspective?

A. Not -- not that I am aware of, no.

Q. So you're saying that we made these changes to deal with waste issues, but we're not dealing with stripper wells as they are understood from a tax perspective.

Is that correct?

A. That is correct.

Q. Okay. Thank you.

So now, I think unless you had something else to add, we can move on to the definition of emergency and pick up where you left off yesterday evening.

A. I'm ready to pick up where we left off.

MR. FELDEWERT: Madam Hearing Officer, if I may, briefly?

HEARING OFFICER ORTH: Yes.

MR. FELDEWERT: Mr. Ames, do you intend to introduce this as an exhibit?

MR. AMES: I certainly can, if there are no objections.

I will move this as Exhibit 4B.

HEARING OFFICER ORTH: Mr. Feldewert, do you have an objection?

MR. FELDEWERT: No. And I appreciate that, just for purposes of the record.

HEARING OFFICER ORTH: All right. Thank you very much.

Let me pause for a moment in the event any other party has an objection to the admission of Exhibit 4B.

(Exhibit admitted, 4B.)

HEARING OFFICER ORTH: It is admitted. Thank you.

Q, (By Mr. Ames) You may go ahead.

A. So if I could ask Ms. Polak to bring up our slide presentation, and I believe we are on Slide 36.

Okay. So I will pick up here. We were going through a couple of the definitions in Subpart 27.7.

Not all of the definitions, certainly, but those that we thought merited a little bit more attention. And emergency is one of those.

The reason emergency -- we wanted to call your attention to it is that gas that is vented or

flared during an emergency is not counted against an operator for purposes of their gas capture requirement.

This is a circumstance in which venting or flaring is deemed not waste, because it is for safety purposes. And I think generically speaking, safety is -- is kind of one of the two caveats where venting and flaring is allowed and not considered waste; and, therefore, not counted against the loss of gas calculation.

So I'll also say here that we borrowed this definition very largely from an existing BLM definition found at 43 CFR Section 3179.103.

That is in OCD's exhibits as Exhibit 37. And you will find that definition at page 79.

So we liked the definition, we liked the way it worked. As I said, we -- we largely followed it.

The definition you can read for yourself. I think the definition part is fairly straightforward and self-explanatory. What's interesting about the definition is that it enumerates six specific circumstances that are not emergencies.

And so the way I think about this is that

the division wants meaningful sideboards on what qualifies as an emergency, because it is going to be an exemption from that venting or flaring and lost gas calculation.

So those -- those six not emergencies are the operator's failure to install appropriate equipment of sufficient capacity to accommodate the anticipated or actual rate and pressure of production is not an emergency.

The operator's failure to limit production when the production rate exceeds the capacity of the related equipment for natural gas gathering system or exceeds the sales contract volume of natural gas.

Not emergencies because those things can be planned for and avoided.

Scheduled maintenance, it's not an emergency.

This one is not part of BLM. This is our own addition, the division's addition. Venting or flaring of natural gas for more than four hours after a notification that is caused by an emergency, unscheduled maintenance, or malfunction of a natural gas gathering system.

So here the natural gas gathering system is how to break down a disruption that can have

upstream consequences including, perhaps, the need of suddenly -- if suddenly the upstream operator is -- takeaway capacity and what should happen.

So the division's math here was that there should be a period of time that doesn't count against the operator. At the same time, the operator should respond to that situation with urgency, and correct it and mitigate it as rapidly as possible.

So the division's suggested language is that there's a four-hour period that is an emergency essentially, and won't count against the operator. But after that it's not an emergency.

The other last two are the operator's negligence, including a recurring equipment failure, is not an emergency.

And then this last one, slightly adopted from BLM. Three or more emergencies within a single reporting area pursuant to Subsection A of 27-9, which we'll talk about in a second. Three or more emergencies within a single reporting area experienced by the operator within a preceding 60 days, unless the division determines the operator could not have reasonably anticipated the current event and it was beyond the operator's control.

So in plain English, I hope, if an operator -- the same thing is happening over and over again, the operator needs to figure it out and stop it from happening.

There are millions of variations on these scenarios. Some operators operate lots of wells in lots of different places and things can change and go wrong, and it's not a pattern.

But I think what this is aimed at is, is there a pattern here, and is there a pattern the operator should identify and correct? And if so, then the continuation of that pattern is no longer acceptable.

All right. The last thing I'll say about this is that our 28 is essentially similar, but there are just a few slight differences, again because of the operations.

The next slide.

I think this is the last definition I want to touch on. We have included the definition of malfunction, differentiated from an emergency. And venting or flaring during a malfunction does count against an operator's loss of gas for accounting purposes.

So that's -- that's the main reason there

is a definition of malfunction, as well as emergency. They are treated differently in that gas capture application.

Next slide.

So we are transitioning now out of definitions out of Subparts 7 of 27 and 28, into Part 8 of both -- both rules.

And this rule heading is venting or flaring that constitutes waste is prohibited.

So this is really the essence of the regulation of venting and flaring. That a general prohibition, if venting or flaring is -- that constitutes waste is prohibited. We acknowledge that there are certain circumstances where venting and flaring does not constitute waste.

We've touched on one of those being a safety aspect, the emergencies.

The other important broad category, I would say, is -- I would refer to those as unavoidable losses.

And those unavoidable losses occur related to some equipment -- equipment such as pneumatics, the way they are designed, the way they function. Even when they are operating properly there is some low volume/low pressure loss from that equipment.

Low pressure/low volume loss is not considered waste.

And there are similar examples. Again generally, low pressure/low volume, where it is considered part of normal operations.

So we did make a couple of changes. They are small on paper, but important in meaning.

From the October draft to the December draft, those are shown in red. It was that switch to indicate that the -- that what is prohibited is that which causes waste.

Next slide, please.

The exact same paragraph. I'm just highlighting each sentence as I go through it here.

The operator has a general duty to maximize the recovery or the gathering of natural gas and to minimize the waste of natural gas from venting or flaring.

And the only venting or flaring that is allowed during upstream or downstream midstream is specified in the rules, in the subsections that follow this Part A.

I do want to respond a little bit to Mr. Feldwert's questions of Ms. Polak yesterday about the general duty to maximize recovery duty or

obligation.

And I would say that we need to read this language and this rule in context.

This is a rule about venting and flaring. This is a rule that the objective, which is set out in Subpart 19.15.27.6 is to -- to prevent venting and flaring, to minimize waste, and protect correlative rights.

This is not a legislative declaration or mandate. This is not a broad, all-encompassing declaration by the -- by the division. This is in a rule that's about venting or flaring, and a subpart of that rule that specifically talks about venting and flaring.

So I don't -- I don't read it to imply or suggest the broader two that Mr. Feldewert indicated yesterday.

The next slide, please.

And finally, in all circumstances, the operator shall flare rather than vent, except when it is technically infeasible or poses a risk to safe operations or personal safety, and venting is safer than flaring.

So here, a lot of things come together. We've got those sort of two generic categories, when

venting or flaring is potentially allowed for safety or technical infeasibility.

And in the safety case, we want to make sure that venting is only done when it is a safer alternative.

We put this sentence in Part A to indicate that it is an overriding requirement for all of the subparts to follow. And the red text indicates that this was a change after the original draft, a substakeholder input.

The alternative here, and we can say this over and over again, each different subpart of the rule where it's applicable, that seemed unnecessary if we put it here, and make it clear that it applies all of the time to all circumstances.

Again, Mr. Feldewert yesterday asked questions about the division's authority to do this. I think those questions were answered well.

It -- it just seems self-evident to me that the agency that regulates waste products from upstream operations, that it is clearly within its authority to do so.

And if the division determines that disposing of this waste product is better done through flaring than venting, I -- I think that that

certainly is the next scope.

I would also point out that Ms. Polak showed a slide yesterday -- and I'm sorry that I don't have the number at my fingertips.

But the slide showed the sharp decline in venting over the last several years.

So from our perspective, operators are doing this now. Operators understand, fundamentally, that venting is to be avoided at all costs, and that flaring is the preference.

So I think we see that action in the real world, and I think the division will continue to insist on that protocol.

Q. Before we move on, a clarifying question.

I heard you say something along the lines if the division determines that flaring is better than venting in some circumstance, it has the authority to do it.

Did you mean to say the commission?

A. Thank you, Mr. Ames. Yes. Certainly, obviously, these are the commission's rules, and it's the commission's decision.

Q. Thank you.

A. The next side.

So now we're going to look at Subparts B,

C, and D with respect to Part 27. And as I think I said yesterday in the introduction, we have three subparts here to deal separately with three phases of operations.

So Part B pertains to the drilling phase, Part C the completion phase, and Part D the production phase on the EMT side.

On the gas gathering side there's really only the gathering aspect of it, so there is only a Subpart B there that pertains to gathering. And I think Mr. Bolander will cover that in more detail than I will. But I will get under way with B, C, and D here.

Fundamentally, the objective is to specify the limited circumstances under which the flaring of natural gas does not constitute waste; and, therefore, is allowed subject to strict controls.

And as I've indicated, those circumstances are -- are specific to the different phases of the operations.

Q. Matt, with respect to the phases of the operations, are these defined terms, drilling operations, separation flowback, completion operations, and production operations?

A. They are, Mr. Ames. They are all defined

in Subpart 7. And that -- yes. The reason for defining them is to make clear when each of those three phases begins and when it ends.

And I think the reason for that is that you need to know what phase you are in, so that you understand what your -- what your allowable venting and flaring -- in this context, what your allowable venting and flaring is, because it is different for each of those phases.

Q. Are you comfortable talking about the definitions -- reviewing the definitions for the commission, or would you prefer that Mr. Bolander do that?

A. You know, I honestly think Mr. Bolander would do a better job than I would with the details of that. It's somewhat technical. I could read the words and tell you what they say, but I -- I know Jim would have a little bit more context for you.

Q. Okay. Thank you.

A. Next slide.

So on this slide we have the allowable venting and flaring with the exceptions to the prohibition for both Part B drilling and Part C completion or recompletion. Recompletion was an addition after the original draft, called out by

some of the stakeholders.

So under the drilling operations, operators must capture or combust natural gas if technically feasible, using best industry practices and control technologies.

In our minds, this indicates a requirement to -- to do just what it says there, capture or combust natural gas during the drilling phase, if it is technically feasible.

Mr. Bolander would be better at explaining why -- what the challenges are during drilling. But clearly, during drilling, one does not want hydrocarbons coming to the surface. And to the extent that they do, it is unavoidable, there are ways to deal with that. And that's the reference to the technically feasible using the best industry practices and control technologies.

I do not believe technically feasible implies absolutely no economic consideration. I think technically feasible is a modifier of best industry practices and control technologies.

I think we're asking operators to use what is out there, what is the best there is, to control venting and flaring during drilling operations.

And there is the usual. You will see this

often. Exception for emergencies or malfunctions to avoid a risk of immediate and substantial adverse impact on safety, public health, or the environment.

So these are real emergencies with real potential consequences of an immediate and substantial nature that are excluded.

Under the completion side, once hydrocarbons begin to flow to the surface during the initial flowback, that can be a lot of fluids mixed together. You have flowback fluid, you have drilling mud, you have hydrocarbons all coming to the surface. There's a point at which those fluids can be routed to a separator and separated safely. And that's the point at which those -- the natural gas must be captured at that point.

Again, Mr. Bolander can be a little bit more articulate than I can about that process.

They must capture that separated natural gas. They may flare only to avoid safety risks to operations or personnel.

And after the original draft, we did modify this rule to include a third allowance for venting and flaring which pertains to off spec gas, meaning gas into which impurities have been entrained, such as hydrogen sulfide, hydrogen,

potentially CO2, or oxygen.

Those things can make it unsafe or infeasible to put gas into a gathering system, so there are circumstances there where it is appropriate to allow flaring of that gas.

Next slide.

Let me say one more thing about the prior slide. And this goes to Mr. Ames' questions about the definitions a little bit.

I know that the completion phase is a phase of some focus by the environmental side.

It is a phase where venting and flaring can occur, and venting can occur. And we have put sideboards on that in the definitions by saying that the separation of flowback period ends not more than 30 days after initial flowback.

So there is a 30-day sort of clock, or put sideboards on how long that separation flowback can last. After that 30 days the gas can go to a gathering line. Okay.

So production. More exceptions here, because production lasts for a long time. It's -- you know, the majority of a well's life is the production phase. And there are many circumstances -- more circumstances throughout the

life of the production that the venting or flaring might arise. So there are a larger number of exceptions here.

Item number one has been stricken. Item number one was originally placed into the rules at the request of NMED.

As the rule making process evolved, as we continued to coordinate and corroborated with NMED, NMED ultimately determined that they did not need or did not see a need for this exception in the rule.

As we looked at it, we concluded that the other exceptions that are in place would cover any circumstances where number one would have otherwise applied. So we have stricken number one.

We've talked many times about number two already. I won't belabor it.

Unloading or cleaning up liquid holdup in a well, subject to best management practices, this is a standard maintenance operation that becomes necessary on wells or gathering lines. The secret here is to impose those BMPs.

When this is done manually, our rule says that an operator must remain on site. The reason they must remain on site is so that once that well has cleared up, once the purpose of the cleanout has

been achieved and gas starts flowing through that well or gathering line again, that's when it must be connected again to gathering. So that's part of BMPs.

We have an exception for exploratory wells that was added. Exploratory wells are usually drilled in areas where there is not available gathering infrastructure. These are wells that are seeking out new formations. There are careful definitions in the rules about what constitutes an exploratory well.

And for the purposes of determining whether that well will be viable, whether that is a viable economic play, the division has created this exception of up to 12 months.

There are some sideboards on that. An operator does have an obligation to get producing gas into a gathering system as quickly as possible. But there's an opportunity for the operator to determine whether or not that is going to be a viable play.

Q. Matt, you mentioned sideboards. Are those discussed further on in the rule?

A. Sideboards are discussed further on in the rule, Mr. Ames. Part of those sideboards may be in

the definitions of what is an exploratory well.

But I think -- I think we'll get to them later. If we don't, you can ask me again.

Q. Okay. And one more question.

I noticed that the division has struck the word "delineation" and replaced it with "exploratory."

Why did the division do that?

A. That change was made, again, based on stakeholder feedback. I believe, interestingly, both the industry representatives and the environmental NGOs preferred the term "exploratory," and the division didn't see any real reason to quibble. And so that -- that change has been made globally everywhere delineation appeared. And it now says "exploratory."

Q. So the name changed, but the content of the definition really didn't.

Is that right?

A. That's correct. It was -- it was a name change only.

Q. Yeah, I believe there is one thing added in the definition of exploratory well. There was a change in F1 from "drilled" to "completed."

Is that something you're comfortable

addressing?

A. In the definitions, Mr. Ames?

Q. Yes.

A. Okay. Let me look.

Q. It's going to be 27.7F1.

A. Right. Got it. Thank you.

Yes. So let me read the definition. And this is one part of a two-part definition.

"Exploratory well means a well located in a spacing unit the closest boundary of which is 2 miles or more from the outer boundary of a defined pool that has produced oil or gas from a formation to which the well is or will be" -- we had said "drilled" and changed it to "completed."

And I'll take a shot at this.

I think the relevant piece here is, where are the hydrocarbons going to be produced from? The distance between the known production is what matters.

So with horizontal drilling, the drill could be 2 miles away, but the hydrocarbons could be producing right next to that other formation, if the lateral extends for 2 miles.

So what matters, in terms of a horizontal well, is where is the production happening? That is

not where the well is, it is where the well is drilled.

I think that was the reason -- for a vertical well, it would matter where the well is drilled and where it's producing from are essentially the same, but it does make a difference in the case of along the lateral or a step-out one.

Q. And changing the word from "drilled" to "completed" covers both vertical and horizontal wells.

Is that what you're saying?

A. Yes.

Q. Thank you.

A. Of course.

Okay. So I think we were on Subpart 5 here, during maintenance and normal operations involving low pressure/low volume venting, normal operations of pneumatic controllers.

And Number 6, I think probably falls into this same general category.

So as I've mentioned, these are the categories in which venting, at low volume and low pressure does happen in the normal course of events, and is considered infeasible to -- or infeasible or impractical or uneconomic to capture and attempt to

put into a sales line.

And for that reason it's not considered waste. That's the best way I construe that.

Next slide, please.

Okay. We are moving on to Subpart B, which are equipment performance standards.

The equipment in question here is production equipment. By production equipment, we're typically talking about separators, perhaps dehydrators, storage tanks, flares, et cetera.

And so in this section the division is proposing a number of requirements, all intended to ensure that the need -- the creation of gas that would need to be vented or flared is minimized to the greatest extent possible.

And we're focused on leaks, we're focused on incomplete flaring combustion, and so forth.

And the way to accomplish this is from the beginning, before the site is built, to anticipate what that production equipment is going to need to be able to do and to design it properly to do that. And then to use, really, the appropriate latest technology.

And that's collectively what Rule 8E asks of the operators.

So just running through the list, Number 1 must -- must be designed for maximum anticipated throughput pressure.

This means that the equipment needs to be right-sized. If your equipment is undersized, when it sees that higher volume of production that is likely to occur early in the process, it can't handle that. And the result of not being able to handle it is that you end up with gas that's not getting into the sales line for a variety of reasons. And that's gas that's going to be vented or flared.

Not -- no reason to have that happen. All of that takes is good planning.

We've asked for automatic gauging equipment on new storage tanks that are routed to a flare or a control device. That gauging equipment makes it less -- makes it necessarily less frequently to open the feed hatch. Opening the feed hatch releases hydrocarbons in the atmosphere. We want to minimize the opportunities to do that.

Flare stacks, similarly, must be sized and designed for maximum efficiency and equipped with auto igniters or continuous pilot lights.

We are asking that existing flares be

retrofitted within 18 months. This is one of the places where the stripper well or facility exceptions do come in. Those lower-producing facilities will be asked to upgrade their flare stacks, that they replace those flare stacks.

They are not on a hard deadline to do -- replace that equipment. They are allowed to do so as they otherwise would replace those flares.

Q. Mr. Lepore, just a clarification.

In the last -- you just referenced facility exceptions.

Did you actually mean facility definition, the average daily facility production definition?

A. Yes, that is what I meant.

Q. Okay. So we're not intending to exempt anyone through this particular provision. This provision works in conjunction with the definition that you described earlier.

Is that correct?

A. Yes, absolutely. That's right. If the facility meets the definition of the average daily facility production of less than 60,000 cubic feet, they get a different -- have a different time line for -- for replacing those flares.

Q. And while I'm interrupting you in the flow

here, I have a question about the point you made earlier about flare stacks being properly sized and designed.

A. Yes.

Q. I noticed that in Section 7.5, the definition of flare stacks.

Could you take a look at that?

I see that the division's proposed to strike the words "and appropriately designed stack" and replace it with "a device."

And then reading on, "equipped with a burner used to flare."

Why did the division make this change from -- it looks like a performance standard to what looks like simply a description of equipment?

A. I know you're not trying to trick me, Mr. Ames. But I think the answer lies in subpart -- in this subpart that we're looking at. Because I think there we have been more specific about what is required of a flare stack in terms of its appropriate design.

So I think we took it out of the definition and moved it into the substantive requirements.

Q. Thank you. I wasn't trying to trick you,

Mr. Lepore. I was leading you inappropriately.

A. So let me see if I can get to this part and do this in a way of sort of continuing to respond to your question, Mr. Ames.

This is Subpart 8E, Subpart 3.

"The operator shall combust natural gas in a flare stack that is properly sized and designed, and designed" -- sorry -- "properly sized, designed, and operated for complete and continuous combustion of gases sent to the flare."

So that is OCD Exhibit 2A at page 4.

So again, I think -- and hopefully Mr. Bolander or Mr. Powell will clean this up for me if necessary. But I think the definition, as I said, was changed, and the substance now appears here in E, Subpart 3.

Going on, we get to AVO inspections in Subparts 5 and 6. AVO stands for audio, visual, olfactory, sort of the tried-and-true eyes, ears, nose observing the equipment, looking for leaks, indications of leaks, et cetera.

And the division is proposing a requirement that those AVO inspections be -- occur on a weekly or monthly routine, depending on circumstances. Those circumstances were spelled out

in the rule, and this is another circumstance where the low-producing wells or low-producing facilities would be added -- than the higher-producing facility. So it's weekly for the higher-producing facilities and monthly, at the -- at the least, very least, monthly for the lower-producing facilities.

And Part 6, there's a place where the division has sought to incentivize the innovative approaches and technologies so that there is technology out there that can take the place of and perhaps be more efficient and effective than AVO.

And if operators have such technology that they want to deploy, we encourage that. What they need to do is come to the division and get division -- the division's approval to do that.

But AVO is by no means the be-all/end-all here. And we encourage seeing that technology deployed, provided that it's approved by the division.

Q. Mr. Lepore, I have a question for you about AVO.

The division has proposed at least one change in the 8E.D.5Ai. We've added the word "externally."

Originally -- so it now reads "visually

inspecting externally."

Why did the division propose to add that word to that subparagraph?

A. This was a point that was brought up by the industry representatives out of a concern that without that descriptor, there would -- it would be implied or inferred that the inspection had to look at the inside of the storage tank, for example, or potentially the inside of other devices -- separators, et cetera.

That's not the intent of an AVO inspection. The AVO inspection is intended to, you know, not put people down inside things.

So we added that indication at the agency's request to -- to make it -- and we made the correction to make it clear that, in fact, it's external.

Q. Thank you. I apologize, but I do need to go back to 27-8D.

This is the list of exceptions to venting and flaring. I see that the division added a few more exceptions. Would the normal operations of being --

HEARING OFFICER ORTH: Mr. Ames, when you turn your head we lose your voice a little.

MR. AMES: Thank you.

Q, (By Mr. Ames) So, Mr. Lepore, I was referring you back to D, and pointing out the division has added a few exceptions to the list of what it's termed activities not otherwise prohibited.

And I see that the division has added normal operation of dehydration units and any treatment units, normal operation of compressors, combustion engines, and commission of turbines and commission of pipelines, et cetera, to purge introduced impurities.

Why did the division add those exceptions to the list?

A. Yeah. Thank you for pointing those out, Mr. Ames.

So I think the best way to explain it is that the division determined that all of those specific operations fall within that general exception of unavoidable loss, low volume, low pressure.

So these were a handful of operations, specific operations, involving specific equipment that we had not included in the original draft. These were things that industry called to our

attention.

And after our consideration, we concluded that it was fair and appropriate to add these to the list.

I'll take one of those as an example. Commissioning pipeline equipment or facilities only for as long as necessary to purge introduced impurities from the pipeline or equipment.

So when new equipment is brought online, testing operations and so forth of that equipment, there are ways in which materials could be introduced into those -- into that equipment.

We do not want those impurities in the equipment when it is turned on for production.

So there's an opportunity here to purge those materials using the natural gas hydrocarbons. And we see that as a safe practice, a reasonable way to do that, as long as that sideboard is on there, that you do that only for as long as necessary.

So that -- again, I hope that answers your question.

Q. Yes. One more question for you, then.

Before we move on, my question concerns exploratory wells. I believe you said earlier that we would address the sideboards or the guide rails

later on.

But I'm thinking, actually not so -- so before we go further, I'd like to take a step back and ask you about that.

In this case, I'm referring to Section ED. It looks like R3. And that sets forth the guide rails for exploratory wells.

I was wondering if you could briefly discuss that.

MR. AMES: Perhaps, Brandon, can we pull up that provision so Matt can see it on the screen?

And if not, I'm sure you would have it in front of you later on in the presentation.

A. Sure. It sounds like Brandon is going to be able to do that for the commission's benefit, so I can -- I'll sit tight.

Thank you, Brandon.

Okay. So yeah. I'll take it kind of from the top. And this is what we talked about with the definition that venting or flaring -- and again, the strong preference here for flaring during the first 12 months of production from the -- this should now read "exploratory well."

We need to do a search and replace.

During the first 12 months of production

from an exploratory well, or as extended by the division for which cause should be provided. And then these are the caveats. And without reading them all, I'll just note the change to Subpart C, provided that within 15 days of determining an exploratory well is capable of producing paying quantities, the operator submits an updated form C 119 to the division, including a natural gas management plan and time line for connecting the well to the natural gas gathering system.

So while there is, ostensibly, a 12-month window, there is an ongoing requirement that as soon as, within 15 days of determining that that well is capable of producing in paying quantities, the operator must be in communication with the division and have a plan for getting those hydrocarbons into a gathering system as soon as possible.

Q. (By Mr. Ames) Thank you.

HEARING OFFICER ORTH: Mr. Ames, we will need a break soon. If you would, come to a good stopping point.

MR. AMES: Yes, thank you.

I want to point out, for the commission's benefit, that regarding the words "delineation" the word "delineation," as it appears in this

subsection, the division has filed an errata to correct those references from "delineation" to "exploratory." It was an oversight when we submitted our last version that is OCD Exhibit 2A.

So we have caught that, submitted a pleading to reflect that, and we'll be sure that in the next iteration of the rule that it is corrected.

May I ask Mr. Lepore one more question, and then we can take a break?

HEARING OFFICER ORTH: Go ahead.

Q. (By Mr. Ames) Matt, I would like to --

MR. AMES: And, Brandon, if you could go to E3 -- I'm sorry -- E4.

Q. (By Mr. Ames) Matt, I just wanted to ask you about the changes in this provision. This deals with securing and anchoring a flare stack at a certain distance from a well and storage tanks.

We proposed a couple of changes here. Would you mind just touching on those briefly?

A. I don't mind. And yeah, I will give this one a shot.

I may ask you to defer to Mr. Bolander.

But changing from a flare stack located at a well spud to a flare stack constructed, I think the logic here was that wells on a multi-well pad

could be spud long after a well -- the flare stack had been constructed, I guess is what I'm trying to say.

So the relevant date was the construction of the flare stack more than the spudding of a given well.

And the hundred feet, I think the language added onto the end there was to acknowledge that there -- it's certainly possible there are circumstances where it would be very, very difficult for an operator to locate the flare stack 100 feet away for some reason. And this is an acknowledgment that there is an alternative available for that.

Q. Thank you. Was this a change that the division is proposing in response to comments from an interested party?

A. Yes.

Q. Excellent.

MR. AMES: I think this is a good place to break, Ms. Orth.

HEARING OFFICER ORTH: All right. Thank you very much, Mr. Ames and Mr. Lepore.

It's 9:55. Let's break until 10:10.

(A recess was taken from 9:55 a.m. to 10:11 a.m.)

HEARING OFFICER ORTH: All right. We are back after a break.

When we broke, Mr. Ames was continuing his questions of Mr. Lepore.

Gentlemen, if you would.

MR. AMES: Thank you, Ms. Orth.

Q. (By Mr. Ames) Matt, I believe you were on Slide 45, that is not currently up.

(Discussion off the record.)

Q. (By Mr. Ames) Matt, were you on this slide or had you gone to the next?

A. I think we were ready to go to the next.

This is the right slide.

And I will apologize. I'm having a little bit of technical difficulties on my end with a -- a screen that I need, so give me a half a second.

(A recess was taken from 10:12 a.m. to 10:15 a.m.)

HEARING OFFICER ORTH: Mr. Ames?

THE WITNESS: Mr. Ames, if you're ready I will proceed.

Q, (By Mr. Ames) Please proceed, Matt.

A. Thanks. Okay.

We had actually talked about this slide already, so I think we can skip over it. This goes

back to our average daily well production and average daily facility production.

These were -- these slides were intended to show you the changes that were made in the last 48 hours.

This one, as well, we have touched on. So I think we're okay to go ahead to the next slide.

Okay. We are moving past Subpart B on performance standards now, and looking at measurement of vented and flared natural gas.

And then this is a sneak preview. The next part is about reporting of the measured, vented, and flared gas. So Parts F and G of 27 go together somewhat.

I want to introduce this subsection by saying that one of the clearest and most consistent messages that came out of the map process was that the existing database and available data around volumes of vented and flared natural gas is not reliable. It's not robust. No one has very much faith in it.

So from the beginning of the process, the division has believed that implementing rules that are robust in measurement and reporting of vented and flared gas is a high priority. And I think the

rules that are presented to the commission reflect that.

The other thing that I would add to that, yesterday I referenced the Methane Guiding Principle, as well as some documents from the International Energy Agency.

Both of those entities and both of those documents also emphasize -- emphasize the importance of strong, good, reliable measurement and reporting.

You can't really effectively know how to address an issue if you don't know the scope and scale of that issue.

And so again, I think that the rules are very robust in this respect, and they are -- that robustness is aimed at getting to some good, reliable data.

So the objectives of the measurement for both midstream and upstream are what I just said, obtain reliable data. That data will be used to establish baseline gas capture percentages.

For upstream and midstream operators that is extremely important in the bigger scheme of this rule, knowing what today's venting and flaring rates are reliably with integrity, which will be the pathway to getting to that 98 percent capture rate

by the end of 2026.

The -- the rules proposed the requirement to measure using metering equipment where that is technically feasible. It does allow an operator to calculate some of the low volume/low flow emissions where putting a meter in place is impractical or infeasible for different reasons.

One of the carve-outs for the average daily facility production/low producers facilities or wells is a -- is -- pertains to the metering requirement. They can use a gas/oil ratio calculation instead of metering equipment for those low-flow producers.

And at the end of the day, the division can require an operator to install additional metering equipment if the division concludes that the operator's methodologies or practices are not providing robust data.

I'll just say that Mr. Bolander can probably elaborate a little bit on the technical details of measuring and metering equipment, and, you know, when it is feasible or when it is practicable. And other than that, I think I'm ready to move to the next slide, unless Mr. Ames has additional questions.

Q, (By Mr. Ames) You can move to the next slide, then I'll ask you a couple of questions later.

So continue, and then I'll fill in afterwards.

A. Okay. Again, this line was inserted late in the -- in the game, to reflect the changes that were made over the weekend, I think, and Monday morning. So we've touched on this, and we can go ahead.

This is the low-producer exception for the requirements to put metering equipment in place after -- for APDs issued after May 31.

MR. AMES: So, Brandon, could you please pull up the exhibit -- I believe it's 4B, the OCD's proposed changes regarding stripper well language?

Thank you.

So if you could go to the bottom of that, F2.

Thank you.

Q. (By Mr. Ames) Mr. Lepore, do you see the document on the screen?

A. I do.

Q. Okay. So this is OCD Exhibit 4B that has been admitted.

I see that the words "after May 31, 2021," have been struck, and new words have been added "associated with the well authorized by an APD issued after May 31, 2021."

The division submitted a notice of errata. I mentioned that earlier, where we indicated that it was an error on our part to remove the phrase "authorized by an APD issued after May 31, 2021," and insert the date at the beginning of this paragraph.

Could you elaborate on that a little bit?

A. Yes. Sure.

You know, I think the grammatical error is maybe the right way to describe this or a scribner's error. By putting "after May 31, 2021," at the beginning, and not tying it to issuance of an APD, the effect would have been that the -- an operator would have had to install equipment on all facilities after May 31, 2021, and that was not the intent.

The intent was for new equipment -- equipment associated with a well approved after May 31, this requirement applies.

So we shuffled it around and tried to make that clearer by saying that the operator shall

install equipment to measure, et cetera, for equipment associated with the well or facility, associated with a well authorized by an APD after May 31, 2021.

So this applies to new -- newly-approved wells or facilities, not everything commencing on May 31.

That was the reason for this.

Q. Great. Thank you.

MR. AMES: And can we pull up Exhibit 2A?

(Discussion off the record.)

MR. AMES: So let's go down to F1.

There you go.

Q. (By Mr. Ames) So, Matt, I just wanted to ask you to explain to the commission why the division has added the words "or estimate" in F1.

A. I think -- I think the reason is that we have said up above that it is appropriate to estimate the volumes of natural gas flared or vented in certain circumstances. And those are spelled out elsewhere, and it is primarily those circumstances, again, associated with low flow or low pressure, where it is very difficult to measure.

So the rules, all along, have contemplated that measurement should be done where it is

feasible, but we understand that there are circumstances where that's not the case. And we've allowed for estimation in those cases.

We've been fairly specific in the rules that if you do estimate, an operator does estimate in their reporting, they will identify the means they used to make the calculation or the estimation, and that potentially any such calculations or measurements are subject to certification by a third party, should the division make that request.

There's some procedural safeguards built into that as well. But fundamentally, it's appropriate to say "estimate" here, because some of those measurements -- some of the volumes will be estimated and not measured.

Q. Thank you.

MR. AMES: Can we go -- can we go down a little bit on the screen to see C4 and C5 and C6 more clearly?

There we go.

Q. (By Mr. Ames) So, Matt, this section is titled "Measurement of vented and flared natural gas," but it also includes provisions regarding estimation, correct?

A. That is correct.

Q. And that's one of the reasons why we added those words in F1?

A. Yes.

Q. And so can you talk about F5 and 6? You earlier just said that the methods need to be verifiable. I think we may have received a comment from the state land office, as well as the environmental groups, requesting that we beef up these sections to ensure that the estimation methods could be meaningfully evaluated.

Is it your opinion that these changes address those concerns?

A. Yes. I think all of that is an accurate characterization.

There was interest from, I believe, the stakeholder groups that you mentioned -- the state land office, as well as the environmental stakeholders -- that these measurements or estimations, in particular, be subject to verification.

There was a range of suggestions, and I think that those stakeholders can certainly speak for themselves as to what they are advocating.

This was the division's solution, that the methodology -- I think it's fair to say that the

division's approach, generally, is one of performance standards rather than prescriptive standards. So rather than say, Thou shalt do it in this way, what the division has said is you must do it in a way that a third party can verify.

And that's, I think, the reason for the changes in both Subpart 5 and Subpart 6.

Q. Thank you.

MR. AMES: And if we could go a bit up and look at F3.

Q. (By Mr. Ames) You notice that there is a substantial change here in F3. Quite a bit has been -- language has been struck, references to measurement standards from API and the international organization for standards, et cetera, and replacement of the phrase regarding industry standards such as API.

Is this -- can you -- is this something you are comfortable talking about, or should we ask Mr. Bolander for more explanation about this change?

A. So I think I can answer it in a more general way, Mr. Ames. And certainly, Mr. Bolander can talk -- can talk about the details. Because if somebody wants to ask me what API and manual petroleum's measurement standard in Chapter 14.10

says, I'm going to be useless.

But I can tell you that the intent of this change -- you can see from the stricken language, this is a circumstance where we had much more prescriptive language. Measurement equipment shall be an Aura meter, et cetera, et cetera.

And I think this change was made in response to feedback from the indus- -- the regulating community stakeholders who proposed -- again, this more of a performance-based standard.

So an industry standard such as API doesn't have to be that. It does have to be an industry standard. It has to be one that can be independently verified by virtue of Subparts 5 and 6 that we just looked at.

But it -- it allows them -- the operator -- to have some leeway, some latitude, about what the best measurement equipment is, and obligates them, I think it's fair to say, to use a recognized industry practice, whether it is 14.10 or another one.

But I think that was the intent, again, was to pivot away from the more prescriptive to the more performance-based.

And again, Mr. Bolander can be more

specific.

Q. Thank you.

A. Okay. We're going to go back to the slide show, then, Mr. Ames?

Q. Yes, why don't we.

A. Okay. And I think we are on Slide 49.

Q. Yes.

A. Okay. So now, we've talked about measurement.

Now we want the operators to provide accurate, detailed reports to the division on a monthly basis about their venting and flaring.

And we have asked them to do so and, as I have said, in a fairly detailed way. This is true for both upstream and midstream operators. And the objectives, you can see again, obtain the reliable, accurate data, increased understanding of operations equipment and emergencies or malfunctions that contribute to venting and flaring.

Again, I think this is a very important aspect of these rules for both the division and the regulated community and the public and other stakeholders, to understand the sources of venting and flaring. And in so understanding, understand better how to reduce those emissions from those

sources.

Providing timely notice to OCD of emergencies or malfunctions, somewhat self-evident. And ultimately this, as I mentioned, will provide the basis for determining an operator's annual gas capture percentage for purposes of the latter portions of the rule here.

Next slide, please.

So the next couple of slides provide some detail on the reporting requirements for emergencies.

I will say that in most regards, the requirements here track the emergency spill reporting requirements that -- I'm sorry, I'm not going to have the rule number at my fingertips, although they are maybe 19.15.29 or C 140. We kind of tracked that.

And I'm not going to read this slide to you, other than to say that there are thresholds of 50 MCF and 500 MCF, which dictate the timing of the reporting to the division.

And as the red text, or the orange text says there, we modified this after the original rules, to make it more consistent with 19.15.29 and C 141 reporting criteria.

Q. Matt, why did the division add the phrase "from a single event," in several places in G1?

A. So I believe the background for that change was feedback from the regulated community that, in certain circumstances -- and I think the ones cited, were lighting storms or storm events, where it might be that they were dealing with multiple incidents, and that they didn't want those multiple incidents counted towards the -- towards the thresholds.

So I think that the single event clarification was -- was to limit it to just what it says, a single event.

And if I'm wrong, someone will correct me.

Ready for the next slide?

Q. Yes.

A. Okay. So beginning in June of this year, six months from now, five months from now, operators will be obligated to file a monthly venting and flaring report with the division. It is 13 specific categories for reporting venting and flaring on the EMT side, and 10 categories in the gathering side.

And you can see from the text that we did reduce those reporting categories. Originally we had 20 and 15. I know there are many lawyers

watching, and so there is one subpart in the 13. So if you count subparts, I think we're at 14.

In that reporting -- and I think we'll take a look at the categories themselves here in a little bit.

But in that reporting, operators must specify whether the volumes were measured or calculated, as we talked about a little bit ago.

And there are requirements on the calculations, as you've seen, that they must be verifiable.

Some of those categories are emergencies, routine repair or maintenance, manual uploading, uncontrolled storage tanks, venting as a result of normal operations of pneumatic controllers.

And OCD is developing a new form, C 115B, to capture this reporting. And there is a bit of a contingency measure in place for the second half of 2021, where the division will notify operators of the means for them to report their venting and flaring for the latter half of 2021, until that form is developed and ready.

Mr. Powell, if you could -- I think we're in the right place here. If you could bring up the page from Exhibit 2B that shows the specific

reporting requirements.

And, Commissioners, this is OCD Exhibit 2B at pages 5 and 6.

Q. Matt, you referenced 2B. 2B is the clean version of our current proposal.

Do you mean 2A?

A. I think what I have prepared is the clean version.

Q. Okay.

A. You see the actual language as it is being proposed. And I'm sorry, it does not show -- this particular exhibit doesn't show redline.

So again, I just really -- the only point here is for you to see all of the 13/14 categories, and Brandon can get them to fit on the page just like that.

So I'm not going to read aloud to you. But you can spend a minute to look through those.

And it's important to say here, I guess a couple of things.

One, all of this is being reported on a monthly basis.

Two, it's detailed in specific. I don't know that the regulated community would like for there to be fewer categories. We did whittle it

down, as I said, from 20 to 13 or 14. We think it's important to have this level of detail for reasons that I think I have already described.

And even though all of these categories are being reported, remember that some of these are allowed venting and flaring insofar as they aren't considered waste.

And an easy example of that is letter 2A, the emergencies not considered waste; and, therefore, will not count against the operator in their gas capture percentage.

Another one that is not counted against them is H, little I. That is the circumstance where there are impurities in the gas stream that make it impractical or infeasible or unsafe to put into a gathering system.

Small L, near the bottom, venting and flaring from an exploratory -- should be exploratory well -- is another one that is not counted against the operator.

So those are called out in Subpart 9 below. But I just thought I'd point it out here, that even though we have many reported categories, not all of those reported categories are considered waste.

Q. Matt, I have a question for you about that.

Why does the division want reporting for categories of venting and flaring that does not constitute waste?

A. I think my answer to that, Mr. Ames, is what the division wants is the best, cleanest, most accurate picture that it can obtain venting and flaring, whether it's waste or not.

And I think a good example of that are the emergencies. There's, quite obviously, so much attention now on methane emissions. You know, very, very much venting is very much frowned upon.

And I think, to the extent that we can say, you know, this arose out of an emergency situation, that is an understandable, reasonable situation where venting is necessary.

So I think, even though it's not waste and not going to count against them in their gas capture percentages, it's important to know those processes.

I would point to -- if we look back a few years, pneumatics. Pneumatics are pretty widely considered to be a not insignificant source of venting. And not so many years ago there were something called high-bleed pneumatics, which were a

tremendous source of venting and flaring.

If you don't measure that and you don't know that, then you don't know to fix that. And now, high-bleed pneumatics have essentially been, you know, replaced almost universally, I think at this point, in favor of no-bleed or low-bleed pneumatics.

And so that's -- it's just -- you know, this is useful information. This is good data. This is data that helps the regulated community and helps the agency be more effective in its regulations.

Q. So, Matt, you said it would be helpful for the division, the commission, the regulated community, to know about venting and flaring in these categories, even if they are not waste.

But do you believe that the commission has the statutory authority to require reporting for venting and flaring that it currently doesn't consider to be waste?

A. I -- I think so, yes. I would say yes, based on what we've previously talked about, about -- you know if I go back to my example of high-bleed, high-bleed pneumatics were, once upon a time, a -- a valid technology.

That technology has been supplanted. As technologies emerge and evolve, then using the out-of-date technology is no longer appropriate. So what -- what is defined as waste changes. And what's, you know, not waste today may be waste in the future, as technologies evolve.

Q. So if I understand you correctly, you are suggesting that the commission could find that it is reasonable to require reporting of venting and flaring that is not currently waste, in order to prevent waste that's required by the statute?

A. Yes.

Q. Thank you.

If you're done talking about this particular document that's on the screen, I'd like to bring up Exhibit 2A.

A. Okay.

Q. Are you done with that one?

A. Yes, I am.

Q. Okay. If we can look at G2.

So, Matt, the division has proposed some additional changes to this language. I'd just like to review those changes with you.

The first is that the division's proposed to add the words "separately," as in the operator

shall separately report the volume of vented natural gas and the volume of flared natural gas.

Why did the division make that -- why is the division making that proposal today?

A. I think back to the draft I mentioned earlier this morning, that Ms. Polak showed yesterday, identifying separately the volumes of natural gas being flared and that being vented, a very, very important distinction, in my estimation, for reasons that we've talked about today already. And we wanted to be sure that we captured that distinction in the reporting.

So I think it's absolutely essential that those volumes be reported separately.

Q. Okay. And in the interest of transparency, I think you said that we have proposed roughly 12 categories of reporting.

But now we are requiring -- well, we would require -- proposing to require -- operators to report their vented and flared gas separately. That actually, technically, increases the number of categories, doesn't it?

A. Sure. I guess maybe it doubles them. I think it's still the same number of categories, but you have to report two different waste streams as

well, when I think about it.

Q. Okay. I just wanted to clarify that with you.

And then I see some additional changes down below. It looks like we added some language regarding reporting by quarter.

Why did the division propose that?

A. And these were some -- I clarified suggestions made by the stakeholder, the industry stakeholders, if I recall, which seemed appropriate to the division to be more specific.

So it is true that beginning on July 1st, the first thing that happens is a gathering of data, not a submission of data. So that explains the first change there.

So beginning in July, the operator will gather data for quarterly reports in a format specified by the division, and I've mentioned that previously, while they're awaiting completion of the form C 115B.

And then the -- I think the regulated community asked for specifics of middle dates, which naturally would be different for the third quarter and the fourth quarter. And those are spelled out in the amended language.

Q. Okay. And all of these changes here in the main part of the paragraph 2, they were all in response to proposals of other parties in their prehearing statements?

A. That is correct. And I'm fairly sure that -- and I want to say -- that the "separately" request came from the environmental NGO side, and the clarifications of the timing of reporting came from the regulated community side.

Q. Thank you.

MR. AMES: Could we go down a bit further to see all of H, subparagraph H?

Q. (By Mr. Ames) Do you see the changes in H1 and H2, Matt?

A. I do.

Q. And I think that you touched on this briefly.

Can you describe again for the commission why -- where this came from, first of all, and why the division thinks it would be a good idea to break this subparagraph in this category into two subcategories?

A. Yes. Again, I think that -- if I recall, in our early drafts the division had an exception for nitrogen and hydrogen sulfide, but not carbon

dioxide or oxygen.

So the regulated community asked for those additional two constituents, or contaminants, to be included in the list.

We understand the reasoning for that and agree with that and added that in.

The distinction between little I -- H little I and HII, or between nitrogen, hydrogen sulfide, and carbon dioxide and oxygen is, that the first three little I are contaminants or impurities that could be in the gas stream naturally -- I will say not introduced by the operator. They could be there for different reasons, but through no fault of the operator.

Oxygen, as I understand it -- this is probably a better place for Mr. Bolander or Mr. Powell, ultimately.

As I understand it, oxygen contamination would be a consequence of the operator's doing, not occurring naturally. So that's why there are two separate categories.

And when we get to the accounting piece of the natural gas reduction requirements, the first three are not counted against an operator's lost gas. H little II is, because of that fact that

it's -- it's through the operator's doing that it would be necessary to vent or flare that gas.

Q. Okay. Thank you.

With respect to Subparagraph L, I see a category added for venting and flaring from a delineation well, as we're currently calling them, and I believe our notice of errata makes that correction.

Why did we add this category?

A. The main reason -- I'm hesitating because I want to make sure that there are not two reasons.

The main reason is, as we've indicated, we believe it's appropriate -- well, let me say it differently.

Exploratory wells are, by definition, put in places where it is unlikely that there is gathering infrastructure. And there is a time period in which it is appropriate, if not necessary, to allow an operator to make a determination of the economic viability of that well.

During that time period it is reasonable for the gas to be vented or flared, with the sideboards that we put in place.

Given that circumstance, we wanted a separate category here to understand, just as we do

with the others, you know, the volume that is coming from that source.

I think for the record, we don't expect it to be a large volume, because we don't expect there to be a large number of exploratory wells.

Nonetheless, we do want to be able to specify and quantify what that number is from the exploratory wells. That's the reason for having an exception -- or I'm sorry -- for having a reporting category.

And then this is one of the categories that does not count against the operator's lost gas calculation.

So that's my best answer.

Q. Thank you. I will have a question for you regarding paragraph 3, but I believe you're going to start addressing the issues in paragraph 3 in your next slide, so I'll ask you at the conclusion of your presentation on that slide.

A. Okay. Fair enough.

So I think with that -- I lost track of who's driving, Mr. Powell or Ms. Polak.

But whomever, if we can get back to the slides, we'll proceed.

(Discussion off the record.)

A. I think you can go to the next one. Okay.

So these next couple of slides just touch on the last couple of subparts of the venting and flaring requirements. We're asking operators to report the lost natural gas, both in a volumetric sort of a gross calculation, and as a percentage of production.

And Number 4 there is, perhaps, one that you will hear more about from the regulated community, who are not in favor of this requirement, that they be obligated to notify and report to the royalty owners in the narrow estate, the volumes of natural gas that are being vented and flared.

I think I mentioned yesterday, in the higher level overview, why the division believes this is appropriate. It is intended -- very candid -- to be a disincentive for venting and flaring, so that those royalty owners know that's money that is being taken out of their pockets.

And I will also point out -- because I know in several places industry is referencing the Colorado Oil and Gas Conservation Commission rules on venting and flaring that were just adopted. And COGCC has included in their venting and flaring rule a requirement to notify the royalty owners of the

volumes of gas being vented or flared as well.

So that's -- that's why this is in here. We agree with the logic of the COGCC and included it.

I know you want to ask questions about 3. I think there's one more slide that has Subpart 5 on it.

Q. No.

A. There's not?

Q. No, there's not.

A. In any event, why don't we go to your questions?

Q. Yes, thank you.

MR. AMES: Can we pull up Exhibit 2A again, please, and focus in on G3, 4, and 5? 8G, 3, 4, and 5.

Excellent. That works for a moment.

Q. (By Mr. Ames) So, Matt, what I'm seeing is that the division has -- is proposing to strike its original language requiring the operator report lost natural gas on a volumetric and percentage basis each month, and replace it with a requirement that the division will do this.

Why is the division doing this? Why is the division making this change?

A. Yes. The change was made at the request of the industry stakeholder group. And I'm going to not be able to give you a good explanation of the industry's rationale for that. I apologize. I think this detail got lost and slipped through the cracks in my brain.

I can speculate, but I'd rather not. I do recall that it was based on industry input.

Q. Okay. I can ask Mr. Powell that question during his testimony. I think he has a -- probably a clear understanding of the division's rationale, so we will move on.

I see in G3A --

MR. AMES: If you move down just a little bit there.

Q. (By Mr. Ames) I see that we are allowing the volumes of flared and vented -- vented and flared natural gas that is not suitable for transportation or processing to NT22S and CO2.

Why -- I think you touched on this already. But could you just recap what is going on here?

A. Right. Again, I stated --

I'm sorry, Mr. Powell. Can I just see the beginning of Part A there? There you go. Thank

you. Right.

So I think I did. I did talk about this, but I will try to elaborate or summarize.

The 3 constituents are listed. The nitrogen and hydrogen sulfide and carbon dioxide are considered impurities that may prohibit gas from being put into a system, and which occur naturally or may be entrained in that gas stream through no action of the operator.

That is the reason that gas that is vented or flared because of those contaminants is allowed to be excluded. That is not the case with oxygen, as I understand it.

Q. Thank you. I think you did explain it well the first time, but I appreciate your indulging me.

MR. AMES: If you can go down, Brandon, to subpart -- or paragraph 5.

Q. (By Mr. Ames) So, Matt, it looks like the division is proposing to strike third-party verification. Is that true?

A. It certainly looks that way, but looks can be deceiving.

We have a third-party verification requirement later on, I think in Subpart 9 that

we'll get to here shortly, or maybe Subpart 10.

But in any event, the division's interpretation is that that third-party verification authority extends to all aspects of this rule.

So it previously appeared here in Subpart 5. It has now been stricken. And in a subsequent section the division's determination was that it was not necessary in both places, struck it here, left it in the other place, and feels that it would apply to any measuring or reporting that's within the scope of this rule.

Q. Thank you. That's all my questions on G3, 4, and 5.

So if you want to return to the PowerPoint, please do.

A. Okay. Terrific. Thank you.

By my count, Ms. Polak, we should be at Slide 54. Fantastic.

We are entering a home stretch. The statewide natural gas capture requirements are the third major part of Rule 27 and the fourth part of Rule 28.

This is the heart of the rules' intent, that by the end of 2026 all upstream operators will be capturing no less than 98 percent of the natural

gas that they bring to the surface, and that all midstream operators will be capturing 98 percent of the natural gas volumes that they gather.

Ms. Polak touched on this in her testimony. I wish to reiterate that, to the best of my knowledge, this would be the first-in-the-nation requirement by rule that has a fixed deadline of the end of 2026, and a fixed target percentage of no less than 98 percent.

There are some earlier precedents. One by the BLM in the 2016 rules, that also set a 98 percent capture rate over a period of time. That rule was suspended through litigation.

The North Dakota industrial commission in 2014, by order -- not by rule, but by order -- established a target for capture over time. That target capped out at 91 percent. And that target of 91 percent would have been effective November of 2020, so a few months ago.

But again, that was by order. That order was subsequently modified, and I want to say made less -- less binding, less restrictive.

So while we did look to that North Dakota order for some guidance on establishing this 98 percent, we've gone -- obviously, we've gone

farther than that.

I think it's also relevant to note that that North Dakota order was put in place in 2014, not 2021. So if North Dakota were to look at this again, they might look differently about it.

So there you go. 98 percent by 2026.

The objectives stated:

"Obtain objective, measurable, meaningful reductions of waste from venting and flaring on a realistic, fixed, enforceable schedule."

We do feel this is a realistic schedule. I will point out that -- if I can find the right citation quickly -- it is in the map report, which is your OCD Exhibit 6, at page 155.

There is a Table 2 that shows that venting and flaring in New Mexico now, on a statewide basis, hovers around 4 percent over the last several years.

It is substantially higher in the Permian Basin, not surprisingly. It fluctuates between about 3 and 6 percent. But on a statewide basis, according to that data, it's around 4 percent.

Getting that down to 2 percent over the next several years seems reasonable and doable to us.

We feel we have provided operators with

adequate lead time to establish baseline emission rates before commencing required reductions. And we have done this primarily through performance-based standards rather than prescriptive requirements.

Next slide, please.

So I shared with you the objectives. Let me talk a little bit about how this gets implemented, then.

There are sanctions for operators who are not in compliance with their gas capture requirement.

Maybe this is a good place to clarify that the remainder of 2021, the second half of 2021, that baseline will be established. An operator's capture rate -- sorry, I'll say it differently.

The operator's loss rate will be essentially divided by 5. That's the number of years between now and 2026. And that -- that number will be a percentage number that the operator will have to improve their capture rate by each year.

That is established at the beginning of 2022 and will not change. So if an operator does spectacularly well in year one and gets ahead, that's great. They can spend the next couple of years figuring out how they'll get all the way to

98 percent.

If an operator falls behind, they will have to catch up. There is -- there is no reset, no do-over.

I said that in absolute terms, and not -- things are not always absolute. Operators have the opportunity to request a hearing and so forth.

But the intent here is that it is set and it is then fixed. And operators have those -- that time frame to get to that 98 percent capture.

So with that, the division may deny or conditionally approve an APD or impose other sanctions for an operator that is not meeting its annual gas capture requirements.

Another important tool in the division's toolbox to ensure compliance is that an operator who is out of compliance may see its approved APDs suspended if it falls out of compliance with its natural gas capture rate.

So even if -- as I said, even if the division has approved APDs, an operator is not in compliance, it may lose its right to go ahead and actually drill those approved wells.

And then as a third sort of incentive, or inducement for compliance, we'll talk about a

natural gas capture plan, a natural gas management plan, that is required for upstream operators.

And we have created two tiers for that. A streamlined tier for operators who are in compliance with their capture requirements, and a bit more onerous plan requirement for those who aren't.

Next slide.

Okay. So now substance -- Part A of 27-9 and 28-10, we've touched on this briefly.

There are now two distinct reporting areas, the north part of the state and the south part of the state, dividing line being Township 9 North.

Operators must comply in each area independently. This was a change, I think a meaningful, important change that was made after the initial draft, which was made in response, largely, from stakeholders from the environmental NGO community, who rightly pointed out that there are differences in the production and operations of -- between the two halves of the state, and it made more sense to look at those two halves of the state separately and require compliance in both, so we made that change.

I think I've touched already on the second

bullet point there.

The third bullet point for operators at the baseline capture rate below 60 percent, or who do not keep up with their annual increased capture requirements, those operators must submit a compliance plan.

The logic here is that if you're venting or flaring 40 percent of your gas, you need to get focused and come up with a plan for the division's approval about how you will be able to meet the 98 percent compliance requirement over the time allotted.

And the same is true, if you fall out of compliance, what is -- what is your plan for making up for that lost ground that you lost in the first year, or the first couple of years, knowing that you still have to get 98 percent by the end of 2026.

Finally, there is a provision for the transfer of wells. We were aware that, certainly, operators transfer wells back and forth. Some wells might have a lot of flaring or venting rate, and some wells might have a lower rate, and that might affect their overall compliance or their overall capture or loss rate.

And so we noodled around quite a bit about

how to deal with that. And ultimately what we decided is that the transfer does not change an operator's required capture rate or the time frame in which it must comply.

The operator may come to the division and request a modification, but the burden is on the operator to demonstrate the special circumstance that would justify such a change.

So the default and the anticipated outcome is that there is no change resulting from a transfer. If an operator can make a case for special circumstances, it's within the commission's discretion. The -- commission I think is the right term here -- to grant a modification to the requirement.

Q. Before you move on to 2B, can we bring up Exhibit 2A and look at Section 9-8, 1 through 4?

MR. AMES: Okay. Thank you.

Let's curse down a little bit more, Brandon, to 9, 3, and 4.

Q. (By Mr. Ames) So, Matt, you were just discussing the operator's obligation to comply with the natural gas capture requirements for acquired assets.

I do believe you said that the commission

was able to decide. But I think if you look at the last line in paragraph 3, it's the division that would be making that decision.

Is that correct?

A. Yes, that's correct. I stand corrected.

Q. Okay. I did want the commission to see that the material that you were just discussing is -- is essentially new.

Is that right?

A. Yes.

Q. So originally at 9A3, we had a very simple statement about an operator who acquires one or more wells from another operator has to comply with its statewide natural gas requirements.

Did that seem imprecise to the division? Is that why the division is making this change?

I mean, whose statewide requirements was the acquiring operator to comply with?

A. So yeah. Let me -- give me just a second to sift this out, Mr. Ames.

So here's my -- my hesitancy is, I think the original rule may have been written at a time when there was only one statewide capture requirement, not -- not the two different areas. That may have contributed to part of this.

I think fundamentally, the intent here hadn't changed, that the operator's acquisition of one or more wells from another operator shall not affect its natural gas capture requirements.

But as I described, there is the opportunity for the operator, within 60 days of the acquisition, to request a modification to the gas capture requirements.

I do remember that there was some input from the regulated community about these requirements. And that's -- I'm sorry, but that is the best I'm going to be able to do on the reasoning behind that change.

Q. All right. We can ask Mr. Powell about that during his testimony. I think he will have some insight into that as well.

With respect to paragraph 4, this is a fairly lengthy addition that the commission is proposing.

Is this what you described in your slide regarding operators who are out of compliance not being allowed to spud wells, even if they have approved APDs?

A. It is, yes. And I'll ask Mr. Powell to scroll down just a little bit, so we can see the

full language of Subpart 4, maybe. Maybe not.

Q. Could you just walk us through how this works, the way that this proposal is intended to work?

A. Yes.

So, Brandon, I apologize. Why don't you make it a little bit bigger, and then we'll just scroll line by line.

So -- yes. So the question arises, and I will say that this was an important point for the environmental NGO stakeholder community.

You know, we have this -- this gas capture target, we have this fixed time line, and what should be in the consequence if an operator is not keeping up with its compliance targets. Should it -- should that operator be allowed to continue to spud, drill new wells?

And again, obviously, the different stakeholder groups can speak for themselves.

The division concluded that it should -- I'll say it differently.

I think the division felt that the commission would have the authority to suspend APDs for an operator who was out of compliance, even if those APDs had previously been approved. That's

sort of the genesis of this rule language.

So the division's proposal here is that an operator that is out of compliance with the natural gas requirement for the previous year must submit a compliance plan demonstrating its ability to comply with the natural gas annual capture requirement for the current year.

So let me try to say that in real terms.

In the beginning of 2022, an operator will be told that on an annual basis it must increase its capture rate by X percent. Let's just say X percent is 3 percent.

If, at the end of 2022, an operator has failed to make the 3 percent, under this rule, by March 30 the operator must have submitted a plan to the division explaining how, by the end of 2023, it will have reduced its capture -- I'm sorry -- increased its capture rate by 6 percent.

I think the division's concern is that once you fall behind it gets increasingly difficult to catch up and keep up. So that's the logic here.

You now have to demonstrate to the division how you will comply, how you will make up what you didn't capture in the first year, and keep up with the current year's requirement.

If the commission determines, after a reasonable opportunity to meet with the operator, that the compliance plan does not demonstrate the ability to comply with the gas capture requirements for the current year, the operator's approved APDs for wells that have not been spud shall be suspended pending a division hearing to be held no later than 30 days after the determination.

So the -- so the process here is that the operator submits a plan, the division evaluates the plan, the division gets the opportunity to the operator to meet and confer and discuss.

And if the division determines that the plan is inadequate, the APDs are suspended. And the operator has the opportunity to challenge that suspension.

Q. So in having the ability to challenge this suspension, is that really something new or different? After all, the division is taking away some of the permission it's given.

Is it typical for a regulator of the industry to have some right to challenge any agency's decision to revoke a prior granted permission?

A. With the caveat that I'm not licensed to

practice law in New Mexico, I would say yes. As a general proposition, if you suspend somebody's licenses or permit, they -- they have opportunities for due process and redress.

Q. Which would likely exist regardless of whether we set it or not.

Is that right?

A. That is likely true.

Q. How about this last phrase, the last sentence in this section?

What does this mean?

A. I would interpret this to mean that the remedy specified in this subpart is not the exclusive remedy available to the division, and the division wanted to be express about that, perhaps in anticipation of an argument that because you specified this remedy, all the others are excluded. And then that is not the intention, and the division wanted to be clear about that.

Q. Thank you. I think we can move on to your next slide.

A. Okay. This now gets into Subpart 2 of 9B and 10B, which Subpart B we have called accounting.

This is similar to, but different from, the monthly reporting requirements that we talked

about previously for monthly reports about volumes vented and flared.

Now, the operator essentially is summing up those monthly reports to have arrived at an annual number. And by February 15 of each year the operator must submit a report certifying its compliance with the state gas capture requirements.

And what the accounting process does, that follows in multiple subsections, is specify the categories of vented or flared gas that are not considered lost gas.

And we've talked about those as we have gone along, and they are listed here on the slide. I think the slide captures all of the lost gas exclusions: emergencies, contaminants, beneficial use, and exploration wells.

And I know we've talked about all of those.

So -- but what the operator is doing is saying, I produced a gross volume of gas that is X.

A large percentage of that gas got put into a sales line.

Some of that gas was used for beneficial purposes on the lease.

Some of that gas was vented or flared for

reasons that are excluded from the lost gas calculation.

I get to take those out of the equation, and then I divide that remainder of the lost gas that was vented or flared for something other than the four reasons on the screen, and I divide that by my produced gas total, and I get a percentage.

That's what Subpart B articulates.

There's one more important part of Subpart B that I hope we get to on the next slide, but that's all I want to say about this slide.

The other opportunity that an operator has to reduce its -- I should say it differently.

The other opportunity an operator has to increase its gas capture percentage is to take advantage of the ALARM capture credit.

So it is now seeming like a very long time ago to me. We talked about the definition of ALARM, which is the advanced leak and repair monitoring technology.

If an operator uses that technology and identifies natural gas leaks, reports those leaks to the division and repairs those leaks, it is eligible for a credit against this lost gas percentage.

Given the intent here was to consent

operators to use some of the advanced technologies, the fixed-wing aircraft -- and we are confident there are other -- there will be other technologies that emerge that might also qualify for the credit.

And provided that the operator meets the requirements in the rule, which I have sort of quickly articulated, they must use the technology to identify a leak. They must isolate the leak and ultimately repair the leak in a timely fashion. They must report the leak to the division, and they must be using that technology not just on a runoff basis, but as kind of a routine part of their natural gas capture or management requirements, or practices.

If all of that is done, they can receive a credit of 40 or 60 percent, conceivably raise that credit from the initial draft, adjust the volume of gas that was lost from the leak that they identified and repaired. There's a few other caveats on the conditions that they can use.

And that -- again, this gets reported annually. So if an operator gets a credit, they can use that credit any time over the next two years.

So it might not be used in the same year in which that leak was repaired or identified. The

operator can use it strategically, you know, at a time when it's maybe closer to its capture threshold.

The next slide.

Q. Before you go on to that, I have one question about 9B.

A. Of course.

Q. If we could bring up OCD Exhibit 2A.

MR. AMES: And curse to 9B, 9B4. Or I think it's actually 9B5.

Thank you.

Q. (By Mr. Ames) So, Matt, first of all, there's a number of edits here in 9B, the main paragraph 9B and 9B1, 9B2, 9B3, 9B4.

Are these all essentially changes that you've addressed already? You've just addressed in your testimony about what the categories are and which ones aren't?

A. I believe so, yes.

Q. Okay. So my focus, really, is on 5.

We have proposed to add the phrase "which methods shall be consistent with Subsection F of 19.15.27-8 and 9."

Why is the division proposing that change?

Would it help to go back to 8F?

A. Well, let me tell you what I think it says. If I'm wrong you can correct me.

But I think the section referenced there is the section that says that the methodology must be verifiable by a third party.

And because we added that condition, we wanted this requirement, this method used to measure or estimate, also to be verifiable.

So I think it was a creation of parallel construction and not requirements.

Q. Thank you. You can move on to the 9C now, I think, on 59.

A. So back to the slides.

(Discussion off the record.)

MR. AMES: Before Matt proceeds, Ms. Orth, can you advise what our plan is in the next half hour? Are we going to continue or do we need to break earlier?

HEARING OFFICER ORTH: So we have a need for a hard stop between noon and 1:00.

Let me look to Mr. Baca for a thumbs up that we can continue until noon.

All right. Thank you.

Mr. Baca has indicated that we can continue up until noon. If you would, stop then.

MR. AMES: Okay. Well, I believe that we started up around 10:10, 10:15. We may be pushing Mr. Lepore's limits here, who has been testifying for a little more than an hour.

Q. (By Mr. Ames) Mr. Lepore, do you feel comfortable continuing for another half an hour?

A. I -- I am fine to do so, Mr. Ames. I appreciate you asking.

I think we have three or four slides left. And I -- I certainly would hope we could finish in half an hour, and I think everyone else does too.

Q. Okay. Then I'll stop talking about that and move on.

Let's talk about 9C, please.

A. Okay. One more slide, please, Ms. Polak.

Okay. Right.

So we're now back to third-party verification. And I had -- we looked at, previously, a section where the third-party verification language had been stricken, and I promised that it appeared later.

And this is where it appears, in 27.9 -- where are we -- C? Yes, 27.9C.

So the operator -- I'm sorry -- the division may request that an operator retain a

third-party-verified data or information collected or reported, make recommendations to correct or improve the collection reporting, and implement the recommendations approved by OCD.

I think we got a little bit of language to the rule, since this slide was created, that creates an opportunity for the operator to have a bit of a dialogue with the division and see if the division and the operator can reach an accord about what is required with respect to reporting, and whether or not the third-party verification is required.

And ultimately, of course, that decision rests with the division.

Q. Before you move on to 9D, can we bring up Exhibit 2A and look at that language? I'd like the commission to have an opportunity to see the language that you just described.

And while that's being brought up, was this language agreed to with the industry group, New Mexico Oil and Gas Association?

A. It is my understanding that it was; that the division engaged with the representatives of the industry, and there is concurrence on this language.

Q. And does the division believe that this language still provides them with sufficient

authority to provide third-party verification in a meaningful manner?

A. Yes.

Q. So in looking at this provision, I see that we struck Subsections F and G of 27A and replaced it with this part.

What was the purpose of that? What is the purpose of that?

A. So "this part" means Part 27. So all of the entirety of the rule is at -- in play, for lack of a better way.

The division may request that an operator retain a third party to verify any data or information collected or reported pursuant to anything within 27.7.

Sorry -- within Part 27, period. Not just Subsections F and G.

So again, that's why the division was comfortable striking the language that we looked at previously in a different subpart, because now this -- this opportunity, this authority to request third-party verification, applies to the entirety.

Q. Thank you.

Let's move on to 9T, then.

A. Slide 60.

Okay. Statewide natural gas capture -- I'm sorry.

Statewide natural gas management plan. This is a provision that applies only to the upstream side, so it doesn't implicate midstream operations.

And the intent here is to motivate planning, motivate advanced planning or takeaway capacity for operators who are contemplating bringing new wells into production.

This gathering natural gas management plan really was at the heart of North Dakota's efforts to reduce venting and flaring. It is predicated on an understanding that a significant amount of venting or flaring has resulted from associated gas that is associated with wells that are really being drilled to produce oil.

And in some cases, those wells are being drilled out, waiting for appropriate gathering infrastructure for the gas. Under those circumstances, something has to be done with the gas. And two of the choices are venting and flaring of the gas.

So the commission is proposing, and operators -- all operators for all wells, beginning

on June 1st of this year, will file a gas management plan with each APD they submit. And those gas management plans will specify how the operator intends to comply with parts 27-8A through D.

If you recall, those are the parts that limit venting and flaring to specific circumstances.

There is an ongoing obligation for an operator who has filed a natural gas management plan to notify the division if that operator either comes out of compliance with its annual gas capture requirement, or the anticipated gathering capacity that it had thought it had has become unavailable, insufficient, or uncertain.

That ongoing requirement will allow the division the flexibility to modify conditions on its APD -- on the APD -- has approved the APD or adjust accordingly.

And then the final bullet there indicates that it is within the division's authority to conditionally approve or deny an APD where the gathering capacity appears to be unavailable, insufficient, or uncertain, or the operator has filed a venting and flaring plan that is not adequate.

The next slide, please.

So I think we have talked about bullet one.

Bullet two, as I've mentioned earlier, we've got a two-tiered approach here. For operators who are in compliance with their natural gas capture requirement, available for a streamlined set of requirements for their report.

For those who are not in compliance, they must file a more comprehensive plan with some additional information.

And then the last bullet point there that I want to touch on is that the division recognizes that some of the information provided in the natural gas capture plan might be confidential, and the operator may file a request asserting confidentiality of that information.

Q. Before you move on, Matt, I would like to ask you a couple of questions about D1 and D2.

So it's a -- the question will be fairly contemporaneous with your testimony.

MR. AMES: Can we bring up OCD Exhibit 2A?

Q. (By Mr. Ames) So, Matt, I see that in D1, the division is proposing to add two additional information requirements.

Where do these come from, and why is the

division proposing them?

A. So I believe that these were asked of the environmental NGO stakeholder group, that this additional information be included in the natural gas capture/natural gas management plans.

And I believe that they referenced the recent call on the oil and gas conservation commission rules as including similar requirements. And the division felt that these were consistent with the overall approach of the division, again to encourage appropriate planning and foresight and practices to minimize the need to vent or flare.

Q. And so D1D concerns operational best practices.

Why is that a relevant topic of information for a natural gas capture plan?

A. So sort of -- I would say it ties back to, in many ways, the performance standards that we talked about earlier, ensuring that the equipment brought on site is of sufficient size, sufficiently -- again, its technologies to handle anticipated production flows, and ensure that you don't get -- sort of that that gas -- gas that cannot be processed by the equipment that has been put in place.

Q. And how about D1E?

Would you suggest that similarly serves the function of ensuring equipment meets the requirements on the ground?

A. Yes. Yes, a very similar concept, I think.

Q. Okay. So with respect to D2, there's quite a bit of strikeout in the initial paragraph.

What is the objective here?

A. So the objective here was clarifying -- clarifying sort of at what point in time the operator's status, the operator's state of compliance is measured, and -- and what it is measured against.

So I guess another way of saying that is there's a recognition that within the scope of a year, if we go back to an earlier example and say that an operator's obligation was to increase its capture percentage by 3 percent, that might not have happened in February. It might have happened by June. It might have altered in July and still be achieved by December.

So the question is, how do you -- how and when do you make that determination? And that's what we have tried to capture here.

So at the time the APD is submitted for a new or recompleted well, you look at the operator's cumulative compliance for the year. So if they have -- if they were out of compliance in February and are in compliance now, that's what we look at, as it relates to that single number, that single baseline capture reduction rate.

So my example, it's the 3 percent rate for the year. If it was out of compliance the year before, it's still got to catch up. So it's looking at, Can I get to 6 percent?

Q. Okay.

A. I hope that's clear enough. It's a little bit of a tricky concept to explain.

Q. Thank you. I think you did well.

In D2B, little 3, we added some additional language, replaced some existing language, and added some more.

What is the reason for this change?

A. So I think this was a change at the request of the community, rather than the entire natural gas gathering system, as built or planned, if not yet built.

The regulated community suggested that what was most important was the route of the

pipeline from the pipeline well location to the existing or planned interconnect of the natural gas gathering system.

And that seemed appropriate to the division. Gathering systems can be large, they can span long distances. And you know, what -- what, really, the division wants to know is that there is capacity and that the operator can connect to it from a particular well location.

So I think the change was made to try to reflect that.

Q. Okay. Thank you.

You can testify about D4, and you can move on from there.

A. Okay. So D4 and D5 are important. What D4 requires is that the operator, at the time it submits its APD, must certify it will or will not be able to connect to a gathering system with sufficient capacity to transport 100 percent of the anticipated volume of natural gas produced in each well at the time of first production.

So this is -- this is sort of, you know, the moment of truth for the operator. The ask is evaluated, the takeaway capacity. They evaluate the production they expect from the wells they're asking

for. They've anticipated when those wells will come online, and that when all of those things come together they will be able to put 100 percent of that production into a gathering line.

Or there are other things they can be doing with that, and that gets a little bit to the next part. But that is what they must certify to.

I think that is a fairly high bar. We would expect operators to take that seriously and not make that certification without, you know, a high degree of confidence that they had planned accordingly and knew that there would be takeaway capacity.

The next part gets to what happens if the operator cannot make that certification. And if they cannot make that certification, then the operator must talk about alternatives, and they must consider that -- that the -- that either the operator will shut in the wells for which there was not takeaway capacity, or submit a plan, that we have called a venting and flaring plan, to evaluate the potential alternative beneficial uses for the natural gas.

And we have listed some of those potential alternative beneficial uses: power generation on

lease, reinjection for storage or enhanced well recovery, fuel cell production.

You can tell from the way the numbers skip around on the slide, there are some others that aren't listed here.

But that's, from the division's point of view, an acceptable alternative. If you can't put it into a sales line, can it be used for beneficial use? That's really the first question.

If it cannot, then you reinject it and you store it until a different time when there is capacity.

Can you generate electricity with it to power your operations at the site?

It's not -- it's not a finite list, it's not a closed list, but it is a list that provides alternatives to venting and flaring which is, of course, the objective.

Next slide.

Understanding that there's often a significant amount of time that passes between the submission of an APD and the actual turning of the drill bit to the right, the division has imposed a requirement that I've mentioned, that is a continuing requirement for the operator to notify

the division any time after submitting an APD, either that the gas -- the capacity that they thought they had is no longer certain, or that the operator becomes aware that it has cumulative ability for the year to come out of compliance with the statewide capture requirements.

And then finally, at the end of the slide, if the operator cannot make the certifications for the availability of the gas gathering capacity or does not have an adequate venting and flaring plan, the division may deny the APD or conditionally approve the APD by conditionally -- most likely here, we mean that you can proceed with your planning, operator, but you may not drill that well until you come back and demonstrate that you have the capacity, or that you come back and demonstrate that, in the absence of capacity, you have a plan for the alternative beneficial use of that natural gas.

Q. Thank you, Matt. I believe that concludes your testimony.

I have no questions for you at this point.

HEARING OFFICER ORTH: Thank you, Mr. Ames.

I am wondering -- Mr. Feldewert, you would

be the first to cross-examine Mr. Lepore.

Do you have a question or two that would fit in the next ten minutes so that we're not taking a longer break than necessary?

MR. FELDEWERT: Madam Hearing Officer, if I may, can I ask for a 90-second break?

HEARING OFFICER ORTH: Yes.

MR. AMES: Ms. Orth, I made one error. I failed to move the admission of the exhibits through Mr. Lepore, and I need to do that.

So, Matt, can you hang around for one second? I think we'll need to get this done.

Q. (By Mr. Ames) So, Mr. Lepore, did you use, in your testimony, Exhibits 11, 12, 13, 14, and so on through 30 that are attached to OCD's prehearing statement filed December 17?

A. Mr. Ames, will you ask me the question one more time, please?

Q. Yes. I'm asking you about Exhibits 11 through 30 that OCD attached to its prehearing statements.

Did you draft OCD Exhibits 11 through 30? Are these exhibits that you either used to prepare your testimony, and some of which you actually cited here today?

A. Yes, that's correct.

MR. AMES: So I'm going to move the admission of Exhibits 11 through 30 at this time.

HEARING OFFICER ORTH: All right. Thank you.

Let me pause for a moment, to see if there are objections from the other parties.

OCD Exhibits 11 through 30.

Please speak up if you have an objection.

No?

All right. Thank you.

OCD Exhibits 11 through 30 are admitted.

(Exhibits admitted, 11 - 30.)

HEARING OFFICER ORTH: I think now we have probably come close to noon, so Mr. Feldewert with no reasonable opportunity to ask a question.

So let's break now for lunch and return at 1:00.

We'll break from now until 1:00 and reconvene at 1:00.

Thank you.

MR. BIERNOFF: Before we adjourn for the lunch hour, I would like to ask -- and I don't know if I need to follow through on this request.

But I would like to ask now, if possible,

for me to go out of order with the examination of this witness. I may have another commitment that I'm occupied with for a little while after lunch. And so if it's okay with the other parties, I would like to make that request now.

HEARING OFFICER ORTH: Are there objections to Mr. Biernoff's request?

I don't hear an objection, Mr. Biernoff.

I believe that we can take you at 1:00.

MR. BIERNOFF: I'm sorry if I wasn't clear, Madam Hearing Officer. I may be occupied with another matter after the lunch hour, so I'm requesting, potentially, to go later in the proceeding, in other words, to follow, rather than precede counsel for the Climate Advocates.

HEARING OFFICER ORTH: Okay. Thank you. I'm sorry. I misunderstood.

Any objections to that proposal?

MR. AMES: No objections.

HEARING OFFICER ORTH: Thank you.

In that case, Mr. Biernoff, the request is granted, and we will see you later.

MR. BIERNOFF: Thank you kindly.

HEARING OFFICER ORTH: We are on lunch hour now.

(The morning recess was taken at 11:54 a.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

PAUL BACA, RPR, CCR
Certified Court Reporter #112
License Expires: 12-31-21