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

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

APPLICATION OF OXY USA, INC. FOR APPROVAL OF SURFACE POOL-LEASE COMMINGLING, OFF-LEASE STORAGE, AND OFF-LEASE MEASUREMENT, EDDY COUNTY, NEW MEXICO. — CASE NO. 15540

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

September 15, 2016

Santa Fe, New Mexico

BEFORE: WILLIAM V. JONES, CHIEF EXAMINER
PHILLIP GOETZE, TECHNICAL EXAMINER
GABRIEL WADE, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, William V. Jones, Chief Examiner, Phillip Goetze, Technical Examiner, and Gabriel Wade, Legal Examiner, on Thursday, September 15, 2016, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

REPORTED BY: Mary C. Hankins, CCR, RPR
New Mexico CCR #20
Paul Baca Professional Court Reporters
500 4th Street, Northwest, Suite 105
Albuquerque, New Mexico 87102
(505) 843-9241

APPEARANCES

FOR APPLICANT OXY USA, INC.:

JORDAN L. KESSLER, ESQ.
HOLLAND & HART
110 North Guadalupe, Suite 1
Santa Fe, New Mexico 87501
(505) 988-4421
jlkessler@hollandhart.com

INDEX

(8:54 a.m.)

EXAMINER GOETZE: We are back on the record, and this is Case Number 15540, application of OXY USA, Inc. for approval of surface pool-lease commingling, off-lease storage and off-lease measurement, Eddy County, New Mexico.

Call for appearances.

MS. KESSLER: Mr. Examiners, Jordan Kessler, from the Santa Fe office of Holland & Hart, on behalf of the Applicant.

EXAMINER GOETZE: Very good.

Any other appearances?

At this point we'll make note for the record that Mr. Will Jones has joined us. He heard this case and will be the lead examiner for this case.

Please proceed.

MS. KESSLER: I have three witnesses today, Mr. Examiners.

EXAMINER JONES: Will the witnesses please stand?

And will the court reporter please swear the witnesses?

(Mr. Murphrey, Mr. Fournier and Mr. Tysor sworn.)

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

MS. KESSLER: May I proceed?
EXAMINER JONES: Yes.

DIRECT EXAMINATION

BY MS. KESSLER:
Q. Please state your name for the record and tell the Examiners where you're employed and in what capacity.
A. My name is Jeremy Murphrey. I'm a senior land negotiator for OXY USA, Inc.
Q. Have you previously testified before the Division?
A. Yes, I have.
Q. Were your credentials as an expert in petroleum land matters accepted and made a matter of record?
A. Yes, they were.
Q. Are you familiar with the commingling application resulting in this hearing?
A. Yes, I am.
Q. Are you familiar with the status of the lands in the subject areas?
A. Yes, ma'am.
MS. KESSLER: Mr. Examiners, I'd tender

Mr. Murphrey as an expert in petroleum land matters.

EXAMINER JONES: He's qualified as an expert in petroleum land matters.

Q. (BY MS. KESSLER) Mr. Murphrey, please turn to Exhibit 1 and briefly summarize what OXY seeks under this application.

A. We seek to -- or we're requesting approval for pool and lease commingling of certain leases and spacing units located in Sections 22 and 23 of Township 24 South, Range 29 East. That will be in Eddy County, New Mexico. Additionally, we request approval of measurement of well tests -- or based on well tests.

Q. Are you also seeking to include future wells and leases that have been identified in this application?

A. Yes, ma'am.

Q. And are you requesting approval for off-lease storage and measurement of facilities that would be located in the north half of the south half of Section 22?

A. Yes, ma'am.

Q. Is Exhibit 1 an overview of this area?

A. That's correct.

Q. And has OXY brought a facilities engineer and a reservoir engineer to discuss the technical aspects of

OXY's requested measurement by the well-test method?

A. We have.

Q. Let's look at Exhibit 2. Does this show, on page 1, the leases and wells that are the subject of this application?

A. Yes, it does.

Q. It looks like there are seven spacing units identified here. Do four of these spacing units have diverse ownership?

A. Yes, they do.

Q. We'll discuss that in greater detail.

Does this also show eight wells?

A. Yes, ma'am.

Q. And two of those wells, I understand, are producing; is that correct?

A. That is correct.

Q. And six of them are proposed?

A. Yes, ma'am.

Q. What two pools are the wells currently producing from?

A. The pools will be the Pierce Crossing; Bone Spring East Pool and the Corral Draw Bone Spring Pool.

Q. That would be leases -- excuse me -- pools 96473 and 96238?

A. That's correct.

Q. How many federal leases are involved?
A. There will be four federal leases.
Q. And does page 2 of this exhibit contain a legal description of the proposed spacing units and wells, which I'll refer to as leases pursuant to the Division-designated term, that are the subject of this application?
A. It does.
Q. And does this page reflect that the spacing unit located in the south half-south half of Section 23 or the southwest quarter of Section 24 also be included in this application?
A. We do.
Q. Is Exhibit 3 a C-107B for diverse ownership that was filed administratively on June 30th of 2016?
A. That's correct.
EXAMINER JONES: I'm sorry. Can you go back? You said -- you asked for something to also be included in this application. Is that not listed in the application?
MS. KESSLER: It is listed in this application. It just doesn't have any produced or proposed wells, so I wanted to draw attention --
EXAMINER JONES: But the acreage is described?

MS. KESSLER: That's correct.
EXAMINER JONES: Okay.
Q. (BY MS. KESSLER) So does Exhibit 3, the C-107B, describe OXY's proposal to do the well-test method to measurement?
A. Yes, it does.
Q. Were any protests received for this application?
A. No, ma'am.
Q. And why was this application set for hearing?
A. Due to the well-test method, it was requested that our application come up for hearing.
Q. Does this C-107B include C-102s for either of the wells either producing or proposed?
A. Yes, it does.
Q. Turning to Exhibit 4, does this exhibit show ownership broken down by lease?
A. It does. It shows the working interest override and the royalty interest of the leases, as well as the well names.
Q. And you mention that ownership between each of the four leases is diverse, is that correct --
A. Correct.
Q. -- of the different ownership?
A. Yes, ma'am.

Q. Were each of the interest owners provided notice of the administrative application that was filed with the Division?
A. Yes, ma'am.
Q. And were they also provided notice when the application for hearing was filed with the Division?
A. Yes, ma'am.
Q. And no protests were received, correct?
A. No protests were received.
Q. And Exhibit 5, is this a list showing the federal lease API number and the locations of the producing and proposed wells?
A. Yes, ma'am.
Q. It also shows the producing pool?
A. That's correct.
Q. And for wells that have been drilled, this also shows production information, correct?
A. Yes, ma'am.
Q. Is Exhibit 6 an affidavit from Holland & Hart with attached letter providing notice for all of the interest owners in each of the leases?
A. Yes, ma'am.
Q. And that would be notice of this hearing, correct?
A. That's correct.

Q. And is Exhibit 7 a Notice of Publication directed to these same interest owners, providing them notice of this hearing?

A. Yes, it is.

Q. Were Exhibits 1 through 5 prepared by you or compiled under your direction and supervision?

A. Yes, ma'am.

MS. KESSLER: Mr. Examiners, I'd move admission of Exhibits 1 through 7, which includes our affidavits.

EXAMINER JONES: Exhibits 1 through 7 are admitted.

(OXY USA, Inc. Exhibit Numbers 1 through 7 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. So there are seven -- seven drilling units involved?

A. Yes, sir.

Q. And they're roughly 160 acres?

A. 160 with, I believe, two 40s.

Q. Okay. So two of them are mile-and-a-half wells?

A. That's correct.

Q. And four of them are diverse. Are you estimating four of them will be diverse, or you already know they're going to be diverse?

A. Yes, sir, either diverse by working interest or by the NRIs -- or overrides. I'm sorry.

Q. Okay. Are any of them going to be subject to compulsory pooling?

A. No, sir.

Q. Everybody signed up --

A. Yes, sir.

Q. -- already?

You'll be making an application to the Feds, too, or are you going to just go by the onshore orders in effect for the Feds for service commingling here? In other words, the Feds didn't object to this proceeding at all?

MS. KESSLER: That's correct, Mr. Examiner. I believe the concurrent application will be -- has or will be made with the BLM, and they --

EXAMINER JONES: Chose not to participate in this?

MS. KESSLER: (Indicating.)

Q. (BY EXAMINER JONES) So we're looking at all the Bone Spring, just two different pools?

A. Yes, sir.

Q. And one of them has a bigger gravity -- higher gravity, but that's a question for the other witness.

What's the nature of the land involved? You probably went over this already, but is it -- some federal lands, obviously?

A. Yes, sir.

Q. And state lands and fee lands?

A. Just fee and federal. There won't be any state leases, about four federal leases. If you kind of look at our Exhibit 2, of our map there, the fee lease located on this tract will be the south half of the southeast quarter and the southwest -- I'm sorry -- southeast of the southwest quarter of Section 22. The rest of our lands there, we've kind of notated with the federal serial numbers, so the rest of it will all be federal.

Q. Okay. The Federal royalty rates are just burdens of one-eighth?

A. Yes, sir, that's correct. All the federal leases will be 12-and-a-half percent one-eighth.

Q. No overrides? No federal --

A. There will be overrides on all the federal leases, and that's kind of where some of our diversified ownership is coming from as well.

Q. And what about the fee leases? Are they a variety of royalty rates?

A. The fee leases, I believe one of them is 20 percent, with the rest of them being 25 percent.
Q. Oh, boy.
A. The actual 20 percent lease didn't -- it's an older lease that didn't have a "PUGH" clause.
Q. Okay. So it didn't contract in the past?
A. Correct. Yes, sir.
Q. Wow.
So you have -- the lease was actually written with one-quarter royalty rate?
A. At 25 percent.
Q. 25 percent?
A. Uh-huh.
Q. So what about overrides on the fee leases?
A. No overrides on the fee leases. They were? The new leases were taken by OXY USA, Inc. The older lease was taken by a predecessor, Pogo, which, in turn, was purchased by OXY.
Q. OXY purchased the lease?
A. Actually purchased the assets of Pogo, so that's right.
Q. Okay. So you transferred the lease -- the lease has actually been transferred into the name of OXY?
A. Yes, sir, probably maybe about ten years ago.

It's been a while.

Q. Let's see here. What about working interests? Is it all OXY in this whole seven units?

A. The Section 23 wells will be 100 percent OXY.

Our Section 22 wells, we'll have partners in there. We're at about 95 percent interest with, sort of, partners below us.

Q. But you're also including that acreage -- some acreages in 27 and 26; is that correct?

A. I think what we were trying to show there is the layout of the extent of the federal lease and fee lease.

Q. Okay. But it's not included in this application?

A. That's correct.

Q. Okay. As far as future expansion, was this an application that was made with specified acreage and two pools so that you could expand in the future into that acreage, or are you just going for these seven units right now?

MS. KESSLER: Mr. Examiner, the existing units have been identified. And if you look at -- I believe it's the south half of 23 and the southwest quarter of 24, those are the areas of the anticipated development. So they have also been included in this lease as potential commingling --

EXAMINER JONES: Okay.

MS. KESSLER: -- for future. And also we requested in this application any future wells or spacing units that would be within the existing --

EXAMINER JONES: Within the seven.

Q. (BY EXAMINER JONES) And if someone goes nonconsent or something in those seven -- the infill wells within the seven, they would be diversely owned at that point, correct?

A. Yes, sir. That would be correct. It would be a different -- I guess before payout working interest.

Q. Okay. And before penalty, too, then?

A. Yes, sir.

Q. So you would ask for those to be done with well tests also? In other words --

A. Since it's diversified --

Q. -- any well in this case?

A. Yes, sir. And, actually, the nonconsent penalties and partners will all come into effect for wells drilled in Section 22. Section 23 and that little portion in 24, that's lease owned 100 percent by OXY.

Q. Okay. Nobody can go nonconsent there, then?

A. No.

Q. And the OXY unit you were talking about here is --

A. OXY USA, Inc.

Q. -- OXY USA?

You'd only have 5 percent other working interest, and that's in Section 22. So have any of those people -- did you talk to any of those people about -- did they call you about this application?

A. No, they haven't.

Q. Haven't had any --

A. I've talked to them about the actual well proposals and just generally how we were going to work the facilities, but they haven't inquired further about our application.

Q. Okay. But I've seen your name on several applications coming in here. So you provide input or submit service commingle applications; do you not?

A. I will actually provide our ownership, and I will work with our regulatory group as far as compiling the actual application.

Q. Okay. So in some cases, you're going to have a lot more partners than this; is that correct?

A. (No response.)

Q. Have you had other -- I guess you might not be the one to ask. But if you've had inquiries in other applications where you've asked for well testing when you've had less of an OXY percentage, can you think of anything like that?

A. I cannot. At least for this area on the map, we're pre -- our working interest, and I believe this will be the first application I was involved in from this standpoint.

Q. What about surface -- surface ownership? Are you -- are you in tune with who owns surfaces in these sections?

A. I'm familiar. Actually, our surface operations, we have surface landmen that work this area as far as rights-of-way damage and negotiations. I do know where our facility is located in the north half of the south half. It's actually going to be located on fee surface. And we have a surface-use agreement with those owners, and they've been notified of the construction and pay damages.

Q. If this were not approved for well testing and you had to put in separate facilities, would that impact some surface lands or -- not just cost for OXY, but where would you put your facilities? Would you have to go -- you or the landman in charge of negotiations have to negotiate a surface-use agreement?

A. Yeah. It would actually be our surface landman that would go to the surface owners. I actually deal

more with working interests in the mineral side, but having previously worked in the surface division for our company, yes, we would have to go to the surface owners or the BLM, both BLM and fee owners on surface in this area.
OWN

Q. Would it be sometimes hard to obtain an agreement for additional surface facilities?

A. Actually, for this area in 24, this township, we have a large surface-use agreement from one of the main surface owners. So it's under a surface-use agreement for use. There is one more other smaller landowner that we actually have a smaller agreement with. So from a fee standpoint, we have SUAs in place, surface-use agreements.

Q. So even though you'd only do the minerals, you're aware of all the surface issues, it sounds like?

A. Yes, sir.

Q. So the tank battery will be located where at?

A. I believe that it'll be located on the northwest quarter of the southwest quarter.

Q. Of Section 22?

A. That's correct.

Q. Northwest-southwest?

A. Yes, sir, Exhibit 2. It's pretty small, but they have a purple block there in the corner.

Q. Okay. And so if you had to put a facility for wells over in Section 23 -- well, these wells are being drilled from the -- from the -- drilled from the surface side?

A. Common pad.

Q. Common pad?

A. Yes, sir.

Q. Okay. So it's not like you would have to put facilities a long ways away from each other, but it would just be a bigger facility; is that correct?

A. I would really want to check with our facilities engineer because I also know the Pecos River -- I'm not sure if it winds through this section. So that would probably also have an effect on how far away or how close we could have separate facilities.

EXAMINER JONES: Questions for this witness?

EXAMINER WADE: I have no questions.

EXAMINER GOETZE: I have no questions for this witness.

EXAMINER JONES: Thank you very much.

TREY A. FOURNIER,

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

DIRECT EXAMINATION

BY MS. KESSLER:

Q. Please state your name for the record and tell the Examiners by whom you're employed and in what capacity.

A. My name is Trey Fournier. I'm employed by Occidental Petroleum, and I am the facility engineer coordinator for our New Mexico assets.

Q. Have you previously testified before the Division?

A. I have not.

Q. Can you please outline your educational background?

A. I have a bachelor of science from Texas A & M University that I received in 2012.

Q. And can you please outline your work history?

A. I began working for OXY in January of 2013.

Q. Have your responsibilities since joining OXY included the Permian Basin?

A. Yes. I've worked exclusively for OXY in the Permian Basin in New Mexico.

Q. As a facility engineer?

A. Correct, as a facility engineer and a facility engineering coordinator.

Q. Do you have any professional certifications?

A. I have passed the fundamentals exam in 2012.

Q. Are you familiar with the commingling application in this area?

A. I am.

Q. And did you participate in designing the surface facilities that will be utilized for storage and allocation for the subject wells?

A. I did.

MS. KESSLER: Mr. Examiners, I would tender Mr. Fournier as an expert petroleum engineer.

EXAMINER JONES: Mr. Fournier is so qualified.

Q. (BY MS. KESSLER) Turn to Exhibit 8. You said that you supervised the draft of facility plans for these wells; is that correct?

A. That's correct.

Q. Can you please explain OXY's proposed facilities diagram?

A. So shown here is a process flow diagram of the Cedar Canyon 23-3H satellite facility and the Cedar Canyon 22 satellite. On the left-hand side, you have a list of all the wells that go through the 23-3H satellite. Some are drilled. Some are proposed.

All those wells go through inlet manifold, and from there, they will either go to a 6-by-20 production separator or to a test separator. The gas streams from both of these -- from -- off both of these separators go through an orifice meter, where they're metered. After they're metered, they're then combined into a gas stream. They go to our low-pressure gathering system that eventually goes to sales.

The oil and water are both measured with turbine meters. The oil downstream to the oil meter, we have a proving line used to get the repeatability factor for the turbine meter. Downstream at the meters, the oil and water do come into a common water and oil line, respectively. The oil then goes to the 22 satellite where it is stored in common oil tanks before going through a coiless meter for custody transfer.

Q. So the off-lease storage and measurement location is noted on this diagram; is that correct?

A. That's correct.

Q. Can you please briefly discuss cost savings associated with this facility setup?

A. So if we were to have continuous measurement on all of the wells for various interests, we would require an additional five-test separators in this location. Install costs on the test separators is around $200,000. So by doing allocation by well test here, we'd see a saving of a million dollars for the wells listed, shown.

Q. Turning to Exhibit 9, is this a written description of the process that you just described?

A. That's correct.

Q. And this description was also contained in the C-107B submitted to the Division?

A. That's correct.

Q. In your opinion, will approval of this application allow OXY to efficiently and effectively transport, store and market production from the subject acreage?

A. Yes, it would.

Q. What does OXY propose as an allocation method?

A. OXY proposed allocation by well test.

Q. Looking at Exhibit 10, if you could please walk us through this exhibit and explain how production will be allocated.

A. So looking at Exhibit 10, if you look at the chart on the left-hand side, your y-axis is the rate for barrels of oil per day --

(The court reporter requested the witness speak louder.)

A. So on the y-axis on the chart on the left-hand side, we show a rate in barrels of oil per day, and time on the x-axis. So the black line shown is -- would be the rate of the well on a daily basis; whereas, the red bar shown there would be a series of well tests.

So the well -- the well volumes are allocated according to most recent well tests. And so if you have four well tests in a given month, that results in a step function of well tests where every allocation is based off the most recent well tests.

So at the end of each month, you take a look at the well-test volumes that you have for that particular well, and you sum all those preshrunk volumes up for that given well on a monthly basis. And you do the same for all other wells that go through that custody transfer point end of the month.

So then using a part of the whole relationship, you can multiply that part of the whole relationship of the preshrunk volume for that well over the total preshrunk volume for all wells, multiplying that by the total volume that's actually sold at the end of each month, and that is the allocated volume that has been allocated back to that particular well. And all this is done per Chapter 20 of the API.

Q. Looking at Exhibit 11, could you please explain OXY's proposed testing plan?

A. So OXY is proposing a testing plan that looks at and accounts for the anticipated and actual production decline of the wells to help dictate the number of well tests required. So what we've shown here is four different, you could say, life cycles of a well.

We have flowback to pre-peak. We have Range I, we're calling, which would be peak to two months after peak; Range II, 3 to 12 months; and then Range III, 12 months after peak production.

And in each of these life cycles, you have a very -- very unique characteristics of the well. You see dramatic declines in the early portions of the well. And as a result, in order to properly characterize the well's actual production, you do need a different frequency of well tests during those times.

However, as a well begins to decline, as you can see in Range III showing decline rates of less than 5 percent on a month-to-month basis, there are fewer well tests that are needed to characterize what that well is doing on a day-to-day basis. So OXY is proposing taking a look at both our type curves and our actual production and seeing where a well is in its life and looking at the -- whether that dictates the number of well tests we would need to characterize, how many tests that well would need for proper allocation.

Q. Why has OXY proposed allocation by well-test method?

A. So allocation by well-test method is -- it's in

API Chapter 20, and it's an acceptable allocation method. And it allows us to go in and more effectively build these facilities for all of these wells, as well as to more economically justify the facilities we have for these wells. Due to the high -- high decline of these wells from the very beginning, it's very difficult to justify a large number of testers when they'll be underutilized in several months.

Q. You mentioned the high decline of these wells. Will the following witness present decline curves for the producing wells to illustrate the expected decline?

A. Yes, he will.

Q. Were Exhibits 8 through 11 prepared by you or compiled under your direction and supervision?

A. Yes, they were.

MS. KESSLER: Mr. Examiner, I'd move admission of Exhibits 8 through 11.

EXAMINER JONES: Exhibits 8 through 11 are admitted.

(OXY USA, Inc. Exhibit Numbers 8 through 11 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. I want to thank you-all for coming up here and presenting this case because we've had the movement to just include broad stretches of land into one property and take care of it that way.

A. Right.

Q. But this seems -- this seems more versatile and accurate for recordkeeping of the wells.

A. Absolutely.

Q. So in Chapter 20 of the API, they describe well tests and how it should be done?

A. Correct. Yes. Chapter 20.1 is allocation measurement. I mean, it goes through all of the different allocation methods of how you can allocate production back to the wells. The well-testing method is the most common allocation method that I have seen in Permian Basin.

Q. So as far as implementing in the old days, it required pumpers to change the valves and everything. Do you still do that, or do you have automated equipment?

A. So we -- in portions of New Mexico, we do have automatic well testing. I can say that specifically in the Cedar Canyon area, we currently don't have automatic well testing. So a pumper actually goes to the well, and he turns a valve to take it from production into test. And that was due to we were having some issues with our automated well-testing valves. They were imposing back pressure on the wells, which is not -- not ideal from a production scenario.

Looking into the future, as we get more and more wells into these facilities, I do see that we'll probably go back to automated well testing, but it will be a different implementation than we've had in -- in the 2012 time frame that we had had. But now it's manually done by pumpers.

Q. The application you've got here is for all Bone Spring wells, and so -- we're going to talk about the decline rate in a minute. But as far as the difficulty in splitting out the gas from the oil and the oil from the water, what can you tell us about that?

A. What we have seen is -- especially as the wells come on initially, the larger -- larger testing equipment is definitely required in order to get adequate -- adequate separation. That's due mostly -- due to slug flow as they flow initially when they come online. So in order to do that, if you were to go through sizing calculations per GPSA or ASEA {phonetic], any separator sizing, they would say we need a much smaller -- however, due to slug flow, all that is involved with that, you're actually going to need a much larger vessel initially.

Once the wells start to go -- they go off decline and they go off lift, you get a more predictable flow than going through the facilities, but we've seen -- at least when they are initially on flowback at their peak, it is -- it's not -- you know, if you're talking about 1,000 barrels a day, it's not broken out over nice even increments. You get big spikes and then nothing and big spikes and nothing. So it requires much larger equipment for the initial portion.

Q. Are you talking retention time?

A. Retention time, yes. We have not seen -- as long as we're getting adequate retention time, especially in the summer months in Carlsbad, we don't have much issue separating oil, water and gas.

Q. So not emulsions?

A. Once you get to the winter, that becomes -- we start to see paraffin issues and a few other things, but right now we're getting adequate separation with just ensuring we have sufficient retention time on our vessels.

Q. Sand flowback, does that hurt your vessels?

A. Yes, it is. Sand is an issue. And that's just a result of the that move to larger fracs. The sands are going to come along with it. So we're periodically monitoring -- we do use sand traps upstream at the eddies [sic; phonetic] of the wells as they come, before they come into our facilities. But we still have to monitor the sands within the facility itself just to make sure that we're not seeing so much -- strain to our pumps.

Q. How much backflow pressure you got on your wells? What's the wellhead pressure that you are charged with reducing it to?

A. I would say it definitely depends on the lift if we're flowing. I would say we can keep our operating -- we keep our gathering system relatively low pressure and try and operate somewhere around 60 pounds. And so with that being at such a low pressure, we go through our wellhead choke, so we're artificially holding pressure off the wellhead right there for different reasons, for flowback and sand control and reservoir integrity and everything else. But we try and operate facilities at 60 to 70 pounds.

Q. Okay. So what about -- if this were a Bone Spring Wolfcamp combination, would that -- what's the difference in the gravities there and if we see some of these applications come through with variety?

A. Right. Right. I would see very little difference, especially if you're looking at the upper portion of the Wolfcamp. The gravity seems to be very similar to what we see in the Bone Spring 2nd and 3rd.

As you move to lower depths of the Wolfcamp, you might get a little bit higher gravity, but I wouldn't see substantial issues from a facilities side, other than it should actually be easier to separate.

I had a little bit of experience working in the Marcellus Shale prior to working for OXY, and we deal with much lighter condensate. And it's typically easier to separate that out for API or crude.

Q. Okay. Before I forget, one of these units had projected 46 gravity?

A. Yes.

Q. Was that -- was that you that put that down?

A. That was not me, no.

Q. Okay. So that was from -- from your experience, it was Sales?

A. Yes. I don't know who put the API gravity there.

Q. Well, speaking of that, your sales agreements, are they -- you sell the volume per month, or you sell it every day? In other words, are you talking about a monthly thing --

A. Correct.

Q. -- in number ten here, as far as well tests? And I guess you're talking about just taking a certain period of time and deciding how to split it up?

A. Yeah. It's typically drawn on a monthly basis because you're required to close out the custody transfer meter on a monthly basis.

Q. Okay.

A. And so when you're looking at the open and close of that particular custody transfer meter on a month-to-month basis, that's typically how it's always back-allocated as opposed to doing it on a day-by-day basis. Otherwise, you'd have to have allotted run tickets and a lot of -- there would just be a lot of more or less -- there is no way it could be done with as much paperwork and run tickets that are required. So it's typically done on a month-to-month basis so you can close out your meters.

Q. Okay. I'm sorry to drone on and on here, but the Coriolis meters, can you explain those?

A. Yes. It's a long topic of conversation.

So the Coriolis meters recently became accepted by Onshore Order 4 per the BLM for custody-quality level -- custody-quality level measurement. So the Coriolis meter is typically the U-shaped meter that you would see off of most LACTs. Some LACTs are -- displacing LACTs. But most of them the newer LACTs have Coriolis meters.

And they are meters that look at -- using the Coriolis effect, looking at flow through density and flow through that meter, and it's able to give very, very accurate custody-quality measurement.

Q. So it's better than the older way of doing it?

A. Yes. Yes.

Q. Has it got a range of efficiencies that are wider?

A. No, because it's typically fed by a pump.

Q. Okay.

A. So you're going to be limited by what size meter you have. There are 2-, 3, or 4-inch. But there are very wide ranges in between. But it's mostly set by -- you have a back-pressure valve on the outlet, and you're feeding that meter with a pump because upstream that pump is fed by a tank head.

Q. Is it sensor -- is it sensor density?

A. Yes. Yes. So it actually goes through -- there's a lot it goes through that's actually measuring on it. You can actually do transient vapor analysis, which goes and shows very detailed the changes in density and everything as it goes through. You get average densities, flow rates, all of that through the Coriolis meter. And it takes all of that into account as it goes through and calculates the total volume.

Q. Okay.

A. It's been industry accepted for many years now, and I'm very glad to see the BLM now accepting it.

Q. We saw that in the BLM.

A. Yes.

Q. Now, as far as proving it -- proving the meter, how do you do that?

A. So we prove our Coriolis meters per -- obviously for our federal leases. But as far as the actual proving, we have third-party provers come in that use a Master Meter. And essentially a Master Meter is a meter that has been proved by a -- like, literally measuring in, measuring out. So your -- it's being proved by a meter that is the benchmark for -- it knows it's correct. And it's done on either -- at minimum on a quarterly basis. But if you have high flows going through it, it can be done on a greater time.

Q. Okay. We've talked about well tests here, but if you go through the -- one well going through a test separator, you'll design that separator for your average well?

A. You design it for the best well.

Q. Best well?

A. Correct.

Q. So it has to be big enough to handle every one of those wells accurately?

A. That's correct. That's correct.
Q. And a facilities engineer would be the one who would know about that --
A. That's right.
Q. -- in conjunction with the reservoir engineer?
A. That's correct.
We work very closely with the reservoir engineers to look at the peaks of the wells, because if it can't measure the peaks, then it's not really doing much.
Q. So if it's hyperbolic, the decline is going to change a lot and rapidly?
A. Correct. Yes. But separators have a turned-down ratio that will separate -- high end is there.
Q. Okay. So your actual production separator -- if you had to put in separate production separators, they would be typically the size of these test separators, then; is that correct?
A. Depending on the number of wells that would be going through them, it could be variable. If you get to multiple wells going through each production separator, you would obviously want a larger pool separator. But if it's just one to maybe two wells, the test separator will almost be the same size as the production separator

if it's handling two wells.

Q. Okay. The production separators would -- what is the -- what is the -- I mean, I guess we often assume that they are -- if you have a separator on every well that you're exactly measuring everything. But is that correct? In other words, is there some weaknesses in that assumption?

A. The weaknesses in that assumption would be -- is you will have -- what you're measuring at the separator is a preshrunk volume.

Q. Okay.

A. So you will have weathering as it goes through and it sits -- goes from -- you know, if you're operating at 70 pounds, you go to atmospheric pressure, you will have some shrinkage in that regard, as well as difference in ambient temperature, et cetera.

And so by looking at the total sold volume at the end of the month or whenever you look at that volume, it then allows you to take that volume. And then if you look at your total preshrunk volume as a sum of all the wells going into that facility and into a part of the whole relationship and then back-allocating, you get an accurate number of what was actually sold from that well due to losses.

Q. Because you're actually metering through

sales -- the sales meter as the total volume --
A. That's correct.
Q. -- going through, but --
The gas meters are -- are they --
A. They're orifice meters per Onshore Order 5.
Q. Just like they always were, but they're electronically integrated?
A. We'll have an electronic flow computer on the -- off the head of each one of them that does all the flow calculation and all of that per Onshore Order 5 and the American Gas Association.
Q. In this particular application, what would be your percentage of adding up all the well tests versus the actual sales? In other words, is it 95 percent or 105 percent? What's the deviation between adding up all your well tests, and what do you --
A. From a preshrunk -- from a preshrunk perspective to a sold perspective?
Q. Yes.
A. I would say 85 percent.
Q. Okay. So 15 percent inaccuracy there?
A. And I wouldn't call it inaccuracy. I would just call it -- because if it's -- if you're still looking at the volumes as a whole, everything is off 15 percent. So if you normalize for that 15 percent, it

wouldn't -- I wouldn't call it inaccuracy. It's just -- unless you're looking at -- you know, if you want to pay their step turbine meter versus paying for a Coriolis meter, yes. But as far as if you're normalizing across all the wells, then you shouldn't get any inaccuracies. A turbine meter typically has a less than one percent -- meter associated with it.

Q. So you're using the turbine meters upstream of the Coriolis meter?

A. Yes, sir. Yes, sir.

Q. And those Coriolis meters, do they get them cheap enough you could actually use them on your -- with the well test someday?

A. They are considerably expensive in comparison to turbine meters. They also have some limitations in regard to gas breakout that -- turbine meters are still somewhat affected by it, but Coriolis meters are MORE affected by gas breakout than turbine meters are.

Q. Okay. Okay. I'm not sure every company's going to have a facilities engineer as experienced as you, but we have to look at applications from, you know, a whole range of situations -- not just companies but situations.

A. Yes, sir.

Q. And so, in general, what can you tell us about well testing versus continuous metering? I mean, if you were in our situation, what would you want to look at?

A. In my opinion, I think the most critical thing is looking at where a well is in its life and using that to help judge the number of well tests to help characterize it. I believe allocation by well test is an accurate method and is a fair method for allocation of production. But I do think the key is looking at where a well is in its life.

A well that has not been online in three years, you'll see very little variability in it day to day. However, a well that's been online for a month, you can see much more variability, you know, within a five-day stretch. And so on -- when a well is brought online, I would tend to say the more well tests you can get in that earlier portion of the well will help characterize and help better allocate.

Q. So if you design your test separator for the biggest well and you actually design it correctly, which is probably kind of a stretch sometimes, but -- so -- so the inaccuracies would arrive early in the life of the hyperbolic wells?

A. That's correct.

Q. Okay. Thank you very much.

EXAMINER WADE: No questions.

EXAMINER GOETZE: No questions for you.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Yes, sir. Has OXY had a similar configuration like this at any of its other facilities?

A. We have done allocation by well tests at other facilities. I do not know -- I don't think that they were, like in this case particular case, where we have different interests.

Q. Yeah. In general, what were the biggest problems with its operation when you initially started up? Was it just frequency and measurement?

A. I would just say frequency and measurement. Yes, sir.

Q. As far as calibration of everything other than what we've talked about, what's the frequency for those?

A. So the turbine meters have -- they've proven themselves. So you can come in and do proving on those, establish a meter factor on the turbine meters. I do not know the frequency of turbine metering, of proving on those -- custody transfer measurement. We do have measurement techs to go out, and they do what is called a calibration on them. But I do not know off the top of my head.

Q. And as far as disposal, are these going through

OXY's wells, or is this to an agreement put together?
A. For water?
Q. Yeah.
A. I would say -- we have a gathering system in this particular area. I would say the vast majority of the water goes to OXY's own SWDs, although we are working to get some third-party disposals.
Q. Very good. No further questions.
MS. KESSLER: And, Mr. Examiner, the following witness will be able to discuss the oil-gravity issue.
EXAMINER JONES: Okay.

ROBERT C. TYSOR III,
after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MS. KESSLER:
Q. Please state your name for the record and tell the Examiners by whom you're employed and in what capacity.
A. Yes. My name is Robert Chan Tysor. I'm employed by OXY USA, Inc. as a reservoir engineer.
Q. Have you previously testified before the Division?
A. No.

Q. Can you please outline your educational background?

A. Yes. I graduated from the University of Texas at Austin in May of 2012 with a bachelor of science in petroleum engineering.

Q. And please describe your work history.

A. I started full time working for OXY in July of 2012, and I worked as a drilling engineer solely in our New Mexico assets for three-and-a-half years after that. And I've been working as a reservoir engineer for the past year.

Q. And that would be in the Permian Basin as well?

A. Correct.

Q. Do you have any professional certifications?

A. I passed my Fundamentals of Engineering Exam in March of 2012.

Q. You're familiar with the commingling application as it relates to this hearing?

A. Yes.

Q. And have you conducted a review of the subject reservoir in the area?

A. Yes.

MS. KESSLER: Mr. Examiners, I would tender Mr. Tysor as an expert in petroleum engineering.

EXAMINER JONES: He's an expert in

petroleum engineering and so qualified.

Q. (BY MS. KESSLER) If you can turn to Exhibit 12, please, is this the production information for wells that are currently producing?

A. Yes.

Q. And looking at this chart, did the 4H well briefly hit the top of the allowable for a short period of time?

A. Yes. On the average month of February of this year, the Cedar Canyon 23 Federal 4H produced over the top allowable. However, due to the decline, it did not produce over the top allowable. After that month, we do not expect the well to produce over the top allowable.

Q. For other wells, do you believe that they're also capable of producing top allowable?

A. We expect that the wells are capable of producing over top allowable. However, we do not anticipate they will produce over top allowable for longer than three months.

Q. You believe that they'll decline quickly, correct?

A. Yes.

Q. Have you brought a series of declines to illustrate that point?

A. Yes.

Q. If you could turn to Exhibit 13, please, and identify this exhibit.

A. Exhibit 13 shows a map of our Cedar Canyon acreage, as well as several wells identified and drilled into the 2nd Bone Spring over the past several years. I wanted to describe how we created our decline curve for the wells that are not yet producing in this application.

For the Cedar Canyon 2nd Bone Spring 5,000-foot laterals, we have looked at the offset production of four wells just to the south of the proposed laterals, the Cedar Canyon 28-6, 28-7, 27-6 and 27-7, and performed an RTA analysis on those wells, which is basically a reservoir simulation.

We also have looked at the volumetric analysis of the oil in place based on the petrophysics in Cedar Canyon, and we've created a production profile based on the simulation, as well as the historical production of the Cedar Canyon 27 State Com 4H.

We also have a proposed 7,500-foot 2nd Bone Spring lateral, and that type curve is based on a similar RTA simulation analysis, volumetric analysis, as well as a decline curve analysis of the Cedar Canyon 23-4 and 5.

If you go to Exhibit 15, this graph on the left axis shows our daily anticipated production rate plotted against our -- against time and months. And the black curve shows the anticipated production of the Cedar Canyon 5,000-foot 2nd Bone Spring laterals. We anticipate they will come online between 1300 and 1500 barrels of oil per day.

Q. Let me turn you back.

MS. KESSLER: I think we're actually looking at Exhibit 14, Mr. Examiners, for the 5,000-foot.

Q. (BY MS. KESSLER) Correct?

A. Yes. I apologize. Exhibit 14 is the graph that we're looking at.

As I was mentioning, we expect these wells will come online somewhere between 1300 and 1500 barrels of oil per day. But during the first few months, there is a relatively high decline, and we do not anticipate that the wells will produce above top allowable for more than three months.

And you'll notice the four wells that I mentioned that were previously drilled just south of the wells in this application are plotted against -- their production is plotted against the proposed type curve and match fairly closely.

Now we can turn to Exhibit 15, and this

exhibit shows our anticipated type curve for the Cedar Canyon 7,500-foot laterals. Again, it's plotted in black against the historical production in the blue and purple of the Cedar Canyon 23 4H and 23 5H.

The 2nd Bone Spring is an unconventional reservoir that in order to drill and produce economic wells, it requires hydraulic fracture stimulation, and the type curve exhibits are relatively high decline due to the unconventional nature. And the initial production period is from the rock that is stimulated during our fracture stimulation. However, as we move later on in life, the well is producing from under-stimulated rock or a nonstimulated reservoir, which delivers much lower rates. That's why the well exhibits the high decline.

We move to Exhibit 16. It shows a similar map on the right of our Cedar Canyon 3rd Bone Spring wells that have been previously drilled. The Cedar Canyon 16 9H and the Cedar Canyon 10H. We do a have a one-mile n the proposed 3rd Bone Spring lateral in this application. And the type curve process follows a similar RTA simulation, volumetric analysis of oil in place and decline curve analysis on those wells to create our type curve, which is shown in Exhibit 17.

The anticipated production for our 3rd Bone

Spring one-mile type curve is shown in red, and we anticipate that will come on most likely below top allowable and exhibit the same similar shallow -- or steep decline during the initial few months of production.

Q. Mr. Tysor, in your opinion, is the well-test method an efficient and appropriate means by which to allocate production from the subject spacing units?

A. Yes.

Q. And in your opinion, will allocation on a well-test method impair correlative rights?

A. No.

Q. Were Exhibits 12 through 17 prepared by you or compiled under your direction and supervision?

A. Yes.

MS. KESSLER: Mr. Examiners, I'd move admission of Exhibits 12 through 17.

EXAMINER JONES: Exhibits 12 through 17 are admitted.

(OXY USA, Inc. Exhibit Numbers 12 through 17 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. You're kind of unusual because of your drilling experience and you're a reservoir engineer.

A. Yes.

Q. That's kind of like two ends of the spectrum there.

A. Definitely.

Q. So most of these wells are drilled similarly?

A. We have a similar casing design for all of these wells. Even between the one-mile laterals and the mile-and-a-half laterals, in between 2nd and 3rd Bone Spring, they all have the same casing design, just different laying depths and lateral lengths.

Q. Okay. And the completions are similar?

A. Similar frac size between both the 2nd Bone Spring and the 3rd Bone Spring, and our proppant concentration in each stage is relatively similar, somewhere around 1,500 pounds per foot of proppant in the wells that we drill.

Q. The water-oil ratio is -- carries between these?

A. We anticipate the 2nd Bone Spring wells will come on with a water-oil ratio somewhere around 1. We've seen slightly lower, somewhat slightly higher. The 3rd Bone Spring wells, we do see a higher water-oil ratio.

Q. The 3rd has got more water -- pre-water --

A. Yes. Yes.

Q. -- that comes in?

Boy. So you have to deal with the water issues. So your economic limit oil production?

A. I don't know -- I don't know exactly at what point in time these wells, you know, reach their economic limit. The majority of our economics is during the initial two to three years of production. I mean, there is a lot of remaining reserves after that first three years, but the majority of our return is recovered during the first three years of production.

Q. What about production equipment?

A. So I work pretty closely with Mr. Fournier, the previous witness, to design and, you know, get the proper funding for the required production equipment, but he knows much more about that than I do.

Q. Okay. What I meant was the surface --

A. Ah, lift.

Q. -- the pumping units or gas lifts.

A. So we anticipate these wells will flow naturally during the first few months of production. However, for our 2nd Bone Spring wells, we do plan to install gas lift mandrels in the vertical portion of the well, and we'll have surface compression to inject gas to lift the oil column, in the 2nd Bone Spring.

In the 3rd Bone Spring, we're evaluating an option between a gas lift injection or electrical submersible pump.

Q. So that gas lift that you're using in the second, has that got a packer, or is it an open gas lift?

A. We're trialing both. We have one well that has an open annulus, no packer installed. We're trying to inject at a higher rate with the gas lift, but the majority of the gas lift installations have a packer.

Q. Yeah. You did a great job on the matching. Is this Dr. Crafton's RTA --

A. I'm not familiar with that particular methodology. We have some other RTA experts that have helped us.

Q. But you've got the software and you used it?

A. Yes. The software is made by Fekete. It's called Harmony.

Q. Oh, okay. Fekete was bought by somebody else, I believe.

"IHS"

A. I believe by his yes.

Q. Okay. I don't have any more questions. Thank you very much.

A. Okay.

EXAMINER WADE: I have no questions.

EXAMINER GOETZE: I have no questions for this witness.

MS. KESSLER: Thank you, Mr. Examiner.

I'd ask this case be taken under advisement.

EXAMINER JONES: Thank you-all for coming. We really appreciate it.

We'll take Case 15540 under advisement.

EXAMINER GOETZE: And seeing what time it is and our court reporter is still catching up, let's take a 15-minute break and come back at quarter after and pick up the docket again.

(Case Number 15540 concludes, 9:57 a.m.)

(Recess 9:57 a.m.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 15540 heard by me on September 15, 2016.

_______________, Examiner
Oil Conservation Division

STATE OF NEW MEXICO

COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

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

Mary C. Hankins

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2016
Paul Baca Professional Court Reporters