THE ALBERTA ENERGY REGULATOR

PROCEEDING ID NO. 430

IN THE MATTER OF the Responsible Energy Development Act, SA 2012, c R-17.3 and the Regulations and Rules made thereunder;

AND IN THE MATTER OF an Application to Amend Commercial Scheme Approval No. 11475 for the Kirby In Situ Oil Sands Project, KN08 and KN09 Development (Application No. 1936092)

AER PROCEEDING

VOLUME 2

Calgary, Alberta

February 7, 2024

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Proceedings taken at Govier Hall, Calgary, Alberta

February 7, 2024 Morning Session

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M. Riley For ISH Energy Ltd.
A. McLeod For ISH Energy Ltd.

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S. Burns, CSR(A), RPR, CRR Official Court Reporter

(PROCEEDINGS COMMENCED AT 9:00 AM)

COMMISSIONER CHIASSON: Good morning, and welcome back to Day 2 of this proceeding. So before we start, a couple of reminders: One, just to remind everyone in the room that the hearing is being video cast on the internet. So anyone in the hearing room may show up on the video cast, so if you have any concerns, please approach Mr. Lung, Mr. McClary, or Ms. Peddlesden.

The second thing that I want to remind -- and I want to remind everyone who is using a mic in here, the Panel -- we found yesterday over the course of the day that we were having challenges with hearing, so -- hearing people. So as I mentioned yesterday, the mics are very moveable, very adjustable. It seems to work best if you can get the mic close in to you. I also encourage people to use their loud projection voices. My kids are used to me referring to it as my "mom voice", but I know not everyone here is a mom, so -- but I encourage you to project as well. It just makes it a little easier for us because we have discovered the speakers in the room here are not oriented towards the Hearing Panel, oddly enough, so just that reminder.

So other than that today -- and I've got it right -- it came to me during the night -- I wanted to acknowledge that we have Anastasia Stanislavski from hearing services here. I apologize. I had a brain blip last -- yesterday in relation to doing that; otherwise, we have got largely the same folks.

And are there any matters before we proceed? No. Okay. Otherwise, we are back to cross-examination of Canadian Natural's panel by ISH. So, Ms. Riley, we are over to you, and right now we're currently scheduled for a break about 10:30, but you let us know when -- if that -- that -- as you go along if that fits conveniently with where you are at, please.

DEVIN OLLENBERGER, THOMAS BOONE, LENNON ROCHE,
MARC SCRIMSHAW, Previously Affirmed.

GERARD IANNATTONE, JASON LAVIGNE, SCOTT SVERDAHL,
DALE WALTERS, XIANG WANG, PETER THOMSEN, SCOTT BARLAND,
Previously Sworn

M. Riley Cross-examines the Canadian Natural Resources Limited Witness Panel

M. RILEY: Good morning, Panel. I'm going to try and move this microphone for a moment and see how things work out for us.

COMMISSIONER CHIASSON: Thank you. We appreciate --

we appreciate the efforts.
M. RILEY: Let's see. Okay. I think this works.
COMMISSIONER CHIASSON: You're sounding good so far.
M. RILEY: Excellent. Good morning. We will then proceed with our cross-examination of the CNRL panel, and I would like to begin with a reference, please, to Exhibit 50.02, PDF page 33, paragraph 113.
Yesterday, when we started, I mentioned to Mr. Iannattone that there was references to several industry examples which CNRL rejected. Mr. Iannattone could not remember which of these examples I was talking about, so I promised to come back today with a reference for him, and specifically, then, it is this reference that we see in paragraph 113.
Q MS. RILEY: And the question that I have is: If you reject the examples provided by Aardwolf and you offer none of your own, how do you know that what you're proposing is safe?
A G. IANNATTONE: Commissioner Chiasson, we'd just like to conference on this one for a minute, please.
COMMISSIONER CHIASSON: Okay. Go ahead.
A G. IANNATTONE: Could I request a clarification on the question. Is it regarding -- what exactly is it regarding? Is it regarding safety or

steam breakthroughs, or could you please clarify.
Q M. RILEY: It is, in fact, both.
A So it's regarding safety?
Q Safety and steam breakthrough.
A So steam breakthrough through the caprock and steam release on surface?
Q My apologies. Could you repeat that?
A Sorry. What's your definition of "safety"?
Q I think in the broadest sense possible, the impact on GOB, any risk to the environment, people, property.
A Thank you.
A P. THOMSEN: Good morning. I think there -- I think there could be a misunderstanding as far as Ms. Riley's comment about rejection of the examples. I would like to start with speaking to the Cenovus/Wabiskaw pressure example, and CNRL does not reject this. I think there are important learnings from this finding.

So in December 2012, Cenovus was drilling a strat well for the purpose of recovering a McMurray post-steam core. This well is 103/11-15 76-6 W-4. When this well was being drilled, it encountered elevated pressures in the Wabiskaw D bitumen saturated sands, and a pressure of 6,500 kPa was subsequently recorded, and this was unexpected. And Cenovus has investigated this. They have submitted several applications on this topic. Their findings were that this is due to overburdened heat losses from the underlying steam chamber, and there was an undrained thermal expansion of this bitumen in the Wabiskaw D.

So with respect to what are the learnings for CNRL and for the KN08 and KN09, overburdened heat losses will inevitably occur. They are -- they occur with all SAGD projects, and it occurs through conduction. Conduction is a slow process. It has a temperature diffusion coefficient on the order of E minus 6 to E minus 7 metres squared per second. And just for interest, that is about 6 to 7 orders of magnitude slower than, let's say, pressure diffusion in the McMurray bottom water.

The Cenovus example had 6 metres of muddy facies in between the top of the steam chamber and the Wabiskaw D bitumen saturated sands. In -- in KN08 and KN09, we have perhaps 10 to 12 metres, so there is going to be less heating or much slower heating of the Wabiskaw D bitumen saturated sands.

I'd like to quote Cenovus Application Number 1766940, and on page 5 of that application, Cenovus has written: (as read)

> Note that Cenovus expects no vertical gravity drainage in the Wabiskaw member due to laminations that occur throughout the zone.

So Canadian Natural appreciates this example being brought forward. It effectively shows hydraulic isolation of the confinement strata portion in the upper McMurray -- in the muddy facies in the upper McMurray, and, in effect, this confinement strata has been pressure tested, and there was a large pressure difference between the Wabiskaw D bitumen saturated sands and the underlying steam chamber, and this would be several thousand of kPa of differential pressure. Yeah. So that's all we have to say on the -- or that's the update as far as the Cenovus example.

I'd like to hand it over now to either Mr. Sverdahl or Mr. Lavigne to talk to the -- the Surmont example and the findings from them.

A J. LAVIGNE: In the Surmont example, referenced in the Aardwolf report, it was mentioned that it appeared that steam had gotten through a 1-metre thick mudstone, and -- and the term "breakthrough" was applied to that example. However, in the D 54 of that example, it could be seen that the mudstone in question appeared to actually be a 1-metre thick class. There were small breccia pieces at the base and at the top of that class. And so in that one well -- could we bring this up?

A S. SVERDAHL: Exhibit 50-003, page 71, please.

A MR. LAVIGNE: Thank you.
So in this example -- so in this example it appears like steam has broken through this seemingly continuous mudstone. As you can see in the RST log in the upper right, when, in fact, looking at the core photo in the centre, you can see small mudstone chips at both the top and the base of -- of this 1-metre thick mudstone. And the more reasonable geological interpretation is that this is a single mudstone clast that -- this is on the order of a metre thick, and it forms a part of a breccia. And so when you look at the log in the lower left, you can see the small deflection as the gamma tool responds to this, but this particular example would not have lateral extent, and that is why steam moved around this particular clast as opposed to breaking through it vertically.
So this is not -- this is not applicable to the analysis of, say, a regional mudstone of 1-metre thickness. This is a small clast that over time steam is able to move around. And -- sorry. And this is within the McMurray formation, within the reservoir component.
A T. BOONE: Could I add a comment? So, you know, I'm going to say that there isn't anything particularly special about the problem here. I mean there's shales and mudstones that are capping

essentially what is a steam flood zone.

And steam flooding has been going on for 70 or 80 years now. It's -- most of it was done in California before it moved up here, and now we -- and SAGD is what I would say is a mature process here now. So, I mean, we're all informed by 80 years of experience where there have been some cases of steam breaking through the caprock or the confining strata, but they're relatively few and particularly when you're at -- at the low -- the pressures that SAGD is normally operated here.

So the fact that there's no examples of steam breakthrough that -- that we can cite here that are specifically -- says, Oh, you don't have -- you have steam breaking through the type of caprock that we exactly have here, is just a statement that the industry has determined how to work -- how to, you know, design these projects and implement them so that you don't have breakthrough.

Q MS. RILEY: Would you agree that part of the reason we don't see these exact examples is because there is adequate monitoring?

A T. BOONE: No, I wouldn't agree with that. There -- you know, in general SAGD projects initially were heavily monitored and, you know, what's happened is more recently there's less monitoring, but that's because it's becoming a -- a mature process. And as an example of that, the D 54s don't require companies to report their observation well data anymore. So apparently the AER believes that -- that the process has matured as well, and it's not as important as it was in the past to share that monitoring data.

Q And then a further follow-up question regarding the Cenovus example: I believe the terminology used was that there are learnings for CNRL, and I was just wondering how you incorporate those learnings into your monitoring conditions.

A P. THOMSEN: Okay. And the learning that I was referring to was the learning as far as showing a pressure difference between the bitumen saturated Wabiskaw D sands and the underlying steam chamber, and so that learning is that there is hydraulic isolation, and it is required in order to have this pressure buildup. So as far as learnings on surveillance are monitoring, I'm not aware of a -- of a relevant finding for that.

Q I will then move on, and I would request that we go to Exhibit 50.003, Tab 19, at page 64. I would request CNRL's panel to look at this map, and then if we could go to the next page at Tab 20, this is apparently the gas structural cross-section that informs this map; is

that correct?
A S. SVERDAHL: That is correct.
Q This map does not look the same as other maps of the gas structural cross-section; is that correct?
A The difference in this map is the mapping that was provided in our submission was -- was just for the Kirby Mannville II pool.
Q So, to be clear, this section here, this is the new -- the new portion of the map?
A Yes. We added that portion.
Q When did you obtain these logs in Tab 20?
A Just give me a moment.
I just have information on the AA/11-2 well that was drilled in 2008 and the one you see 4-12 well was in 2018. The remaining well, I do not know exactly the rig release date at this moment, but I can check on that.
Q I would appreciate it if you would tell us what that date was. And even if you can't give us an exact date, I would be interested to know whether it was before or after the application was filed?
A Most likely before the application.
Q Can we accept that it was before the application unless you advise us otherwise through the course of this proceeding?
A Yes.

COMMISSIONER CHIASSON: Do you want an undertaking on that, Ms. Riley?
M. RILEY: If the understanding is that it was before the application was filed and we understand that if we don't hear anything by the end of the day, then I do not need an undertaking. If CNRL would rather give an undertaking, then I -- I will take one.
COMMISSIONER CHIASSON: Perhaps we'll make a note of that, Mr. McClary, and we'll circle back by end of day, just to check in on that.
M. RILEY: Thank you.
COMMISSIONER CHIASSON: Thank you.
Q M. RILEY: If the data was available before you filed the application, why did you not map that section?
A S. SVERDAHL: To be clear, as stated, we provided our mapping on the Kirby Upper Mannville II pool.
Q Thank you.
I would then like to go to Exhibit 01.01. It's PDF page 18. It is Figure 18. And what this is is a map of the Kirby north approved and proposed McMurray formation drainage boxes; correct?
A Correct.
Q We note that the KN24 and 25 drainage boxes is not

depicted on this map. Is that because it's not a McMurray formation map or drainage box?
A Those drainage boxes are Wabiskaw D.
Q Can we then go to Exhibit 20 at 02, page 92. Do you agree that the orange on this map is the Wabiskaw D bitumen?
A That is a map of the SAGD pay for the Wabiskaw D.
Q And do you note that here we don't see the KN24 and 25 drainage boxes?
A They are not on this map.
Q Do you also agree that this map purports to show both drainage boxes, approved and proposed?
A It shows the approved McMurray drainage boxes.
Q I'll ask you to have a look at your legend here. It only says "drainage boxes (approved)".
A I am clarifying that it is only the McMurray drainage boxes that are approved.
Q Very well.
Is it possible for you to indicate -- and I will have to give you the mouse -- where the KN24 and KN25 drainage boxes are?
A Roughly in this area here.
Q So adjacent to KN09 and KN08?
A Correct.
Q Do you know when the KN24 and KN25 drainage boxes were approved?

A I will have to confer with my regulatory correspondent here.

Subject to check, we believe the -- those boxes were approved in 2014.

Q The date we have is March 21, 2022.

A The 2022 approval was just for the surface pads.

Q Okay. The point being that at the time this map was filed, KN24 and KN25 was approved?

A Correct.

Q I will then ask to go onto Exhibit 01.01 at page 35. This is the SAGD pay isopach. We know from CNRL's evidence that there is Wabiskaw D bitumen. I assume it's not mapped here because it does not meet the cutoff?

A This is a McMurray map, and it wasn't on this map because it wasn't part of the drainage boxes that we were proposing to develop.

Q If we then go to Exhibit 20.2 at Tab 4, page 92 again. Where you've indicated that KN24 and KN25 is, do you agree that operations there will result in additional heat in that vicinity?

A In which vicinity?

Q Just north of KN09.

A Over time there would likely be some conductive heating in that small portion of the northern -- northeastern portion of the KN09 drainage box into the Wabiskaw D

conductive heating.
Q I will move on, and, as promised, I still have one or two questions on GCMS, and I am back to the statement that was made yesterday that if oil concentrations were not able to equilibrate over geological time, that steam will be able to migrate through these lower permability -- permeability zones. I hope you caught that. That was quite painful.
A S. BARLAND: Yes, I did.
Q Can you describe for me what the mechanism of hydrocarbon degradation over 40 million years is compared to the process of fluid movement over 25 years of SAGD?
A So over geologic time, the oil would have -- originally the McMurray was completely water wet, and then it would have been slightly buried and -- and the sediments would have been charged from lower zones off to the west that would have moved updip into the McMurray formation, so generally charges from the top down. And as it's charging, all -- because the McMurray wasn't buried deep enough to kill the bacteria or to sterilize the reservoir, those bacteria, both anaerobic and aerobic, are still there and would have used that incoming hydrocarbon, the oil to live. So they're basically breaking bonds to get their food, breaking carbon -- carbon bonds.

Q And how does that compare to the fluid movement over 25 years of SAGD development?

A Over geologic time it would have been a slower process. I believe during SAGD we would still expect to see the same barriers or -- or baffles as described by the concentration profiles, but the fluid below or the fluid that the steam actually interacts with would have changed from a solid to more of a liquid, and we would produce that.

Q Isn't SAGD a process that is driven by delta P as opposed to concentration gradients?

A SAGD is more of a gravity process. It's not really driven by delta P.

Q Can you tell me, based on GCMS data, if we have these two very distinct processes, how can you conclude that SAGD will not do what geological time has not done?

A We're using the barriers or baffles identified by GCMS as a proxy for what the SAGD process will do. We've got several industry partners as well as analogs that I've been involved with, and the observation well data in Jackfish would -- would corroborate that evidence.

Q I am then finally moving on from GCMS, and I am moving on to FMI. I would like us to go to Exhibit 01.01 on page 13. 13 -- sorry -- one, three.

This is a table of CNRL's consultation with ISH, and we've heard some evidence about the steps that CNRL has taken to consult. I would like us to look at that very first table and pretty much the second sentence: (as read)

Canadian Natural will not provide the requested microresistivity logs, or image logs, as the core photos provided in Canadian Natural's view is sufficient to provide a comprehensive geological interpretation of the McMurray reservoir and overlaying confinement strata intervals.

So CNRL is telling ISH, You can't get the image logs because the core is enough to inform a comprehensive geological interpretation.

My first question is: Does that mean that CNRL did not consider the FMI information at its disposal to determine whether there were fractures or not?

A G. IANNATTONE: I would say that at this point in time, this was the -- I guess this was recorded in the application. I do believe that we're making reference to preapplication, and I would say that Canadian Natural would view the core information as the primary measured data and the FMI information as more interpretive -- interpretive and more secondary, and so we were trying -- I believe at the time we were trying to aid ISH to seeing the conclusions that -- that we see in -- that we see that there is no issues found in

the core, which is the hardcore -- pardon the pun -- primary data.
Q The request, however, was for image logs, and the response is, You don't need image logs because you can do a comprehensive geological interpretation without them. Do you agree that that is what that says?
A That's what that says, yes.
Q My next follow-up question is: At what stage does CNRL obtain its FMI data? Broadly speaking -- I don't need a specific example -- when do we get FMI data?
A S. SVERDAHL: We run FMI logs as part of drilling strat wells.
Q What we can take from that is that I see there's --
A Just one moment, please.
Just to -- just to supplement that last statement, we -- we also core a significant amount of our strat wells and use the FMI logs to conform -- confirm what we're seeing on that core data. We don't run core on every log or every strat well, but it's another tool, the FMI log, to confirm our -- our integrated approach of interpreting what we're observing in the subsurface.
Q The only point I was trying to get at is we obtain FMI data at the time of drilling. It doesn't happen after that?
A The logs are run as part of the drilling of the well.
Q So it is safe to say that all of the FMI data that CNRL

has it had at its disposal, and one would believe in a usable format at the time this application was filed, other than, of course, the new wells that was drilled in between?

A G. IANNATTONE: That's correct.

Q I would then like to go to Exhibit 50.003, Tab 10, page 55. And I would like us to look at this header. I don't know if you will be able to see it. Perhaps we can make it bigger. I promise that wasn't I.

Do you agree that this is a Schlumberger log or report?

A S. SVERDAHL: That log was run by Schlumberger. That is correct.

Q If we can then just go to the inscription on this log. Do you agree that it was not ISH who identified that fracture. It was, in fact, the interpretation of Schlumberger?

A Yes.

Q I would then like to go to Exhibit 15.01, paragraph 113.

MR. LUNG: Sorry, Ms. Riley. What page number?

M. RILEY: Sorry. I just realized I did not tell you. Let me see if I can find 113 for you. It is page -- page 27.

A G. IANNATTONE: Ms. Riley, if you allow me, I would like to go back to the previous question and

provide an additional response.
Q I will be hard-pressed to refuse you. Please do.
A Oh, okay. Thank you.
Yeah. I just wanted to bring up that in Draft Directive 23, I think it was that -- I don't have the exact section. I think it's 4.2, but in there it states that the applicant must make reasonable efforts to -- to address stakeholder concerns, and I guess what I would say is in providing the core data Canadian Natural thought they were making a reasonable effort. It does not state in Directive 23 that all the data that you have in your possession, either confidential or non-confidential, needs to be supplied. Thank you.
Q If we can then return back to 15.01, and we're looking at paragraph 113. Here CNRL tells us that they were 14 fractures identified on image logs and various formations in which they saw them. My question on that is: Are there any consequences for -- for these -- for these fractures that exist, for instance, in the Clearwater B and in the Wab B?
A S. SVERDAHL: We would conclude this is a minor amount of fracturing, and there would be no significant consequences of these fractures being present.
Q So what we see here is fractures above and below the confinement strata but not in the confinement strata;

is that correct?
A Correct.
Q Could you explain the geological process that would result in fractures above and below but not in the confinement strata?
A J. LAVIGNE: First of all, it's worth pointing out, as we discussed, the differences between fractures identified in core and fractures identified in image logs. Image logs are run over the entire interval. The coring is -- is done over the reservoir units in the confinement strata. We don't core the entire well in -- in all of the holes. And so we do an analysis of fractures in those units. There are fractures to be known in all of the regional shales above. The point being made is that it's of -- they're very minor, and in other places, especially in areas to the east where there's a significant amount of salt dissolution, there can be quite extensive faults and fractures in some of those overlying units that in the Kirby north area would -- would form part of the caprock interval.
There are also fractures observed in the Paleozoic in the underlying limestones. Those fractures are typically very ol and mostly healed. So we don't actually feel that -- we don't actually feel that those -- those lower fractures or the overlying ones

are -- it's -- it's not surprising that we see a very low density of fractures in the overlying caprock shales or in the underlying Paleozoic the deposits within the McMurray and Wabiskaw that form both the reservoirs and the confinement strata were not fractured in -- in the same way.
Q That was very interesting, but my question was: What the geologic process would be that would lead to this?
A The shales have a different rheology and -- and rock strength than the -- than the bitumen sandstones, and so they're -- they're more prone to fracturing. But the point is that two fractures within a very large thick caprock section is -- is not a significant amount of fracturing.
Q I would then like to move on to Exhibit 15.01, page 195. I would like for us to zoom in on the first 2 metres of -- of that image. Are we at maximum resolution? Perhaps a little bit smaller so we can see the first 2 metres, please. Like that is good.
My question is: Can you tell me from this image whether there is a fracture or a bed in the top of this image, and as a part of that answer, could another interpreter or the AER make any determination from this image?
A X. WANG: Actually, this looks like a -- looks like static. The one way the interpreter

interpret the image, we usually can play the contrast of the colour wrap. We can go to dynamic, and then we can play with. For this particular image, I will say you may not see the details, but one interpreter actually doing the work, we can see more than that.
Q   Certainly, sir. You've essentially answered two of my follow-up questions and that was that we use this image to do our interpretation and that you use a dynamically normalized image in your interpretation, and I assume the answer to that was yes?
A   Well, that's just the routine for every interpreter. We both see the dynamic and the static, and we play with -- with the contrast of the resistivity, so we can see more than that.
Q   So given that CNRL did not use this image for its interpretation, is it fair to say that there is further detail that does not form part of this application?
A   No. I will say no. Because once you got the DLIS this file, you got to the software. You can play with it. This just a one displacement.
Q   So -- so from your evidence, I take it that you need the DLIS file to actually do this interpretation?
A   Yes.
A   S. SVERDAHL: I would add that we were not requested for the digital data.
Q   You, in fact, were, but we will get to that.

If we could then go to Exhibit 50.003, Tab 18. It's page 63. I'm going to ask you to expand the image, focus on the middle of the page until we can see any of the two bars as the only image on the screen. If you can keep going, that's good; if you can't keep going, that's also good. Excellent.

First question: Can you read the depth for me?

A The depth on this image is -- is blurry; however, you can, if you zoom back out and reference it to the log on the left of this image, get a good indication where this is.

Q Is this what the image looked like when you did your interpretations?

A X. WANG: Actually, this is just a Tiff or JPEG file of a screenshot --

THE COURT REPORTER: A what file?

A X. WANG: A JPEG or Tiff file of the -- of the actual image. Some -- sometimes the resolution is worse than you actually looking at the screen, when you do the interpretation. That's where the comment, right? This is just a displacement of one of the pictures -- image.

Q M. RILEY: So if this was all that you got, would you be able to do a good job of interpreting this?

A This is a misunderstanding. We do not interpret the

image log on the page's sides 'cause this shrinked several thousand metre -- hundred metres into one page. We -- we do not do that.
Q So to expect someone else to try and interpret this and given only this would be unfair?
A I don't think any interpreter, professional interpreter, will interpret it from the page size.
Q So from the information that CNRL put on the record, neither ISH or the AER could actually use these images to do an interpretation?
A Well, the --
A S. SVERDAHL: This slide was created in the reply submission to tell the story that we've drilled a well through an area of expected differential compaction. It wasn't meant as a figure to interpret from.
Q If we could then move on to Exhibit 15.01, Tab 25. It's page 340. My apologies. It's obviously not page 340. Let's have a look. It is, in fact, page 339.
M. RILEY: Could we increase the image? I would like the yellow block to be in the centre of the screen and as large as you can make it.
Q M. RILEY: I would like to draw your attention to this feature here and this feature here. What are the sigmoidal features that I've indicated?

A X. WANG: Okay. That's -- we call it diagonal -- two marks. So usually you can see on the image log at least two sets that come from the side to -- so within each set you can see that they're roughly parallel. They're straight lines. And when they intersect, you don't see the curvature of the fracture -- see. So you can see multiple -- actually, if you follow the trend and you can see the multiple part of that. That's quite common, and -- oh, what happened? Okay. So you can see actually -- when you see this kind of features, you need to stand back to zoom out and not just the 1 metre or half metre. You -- you can see the trend start from up right corner here. You can go from here, and there are some -- some trend here, and for the other set, you can see the marks -- the two marks go through there, and it goes through there. They result from the hole spiral. So it's two marks. It's kind of artifacts we see quite common on the image log.

Q May I have the mouse back? Because I think we are misunderstanding each other about which area I'm referring to. I am specifically talking about this mark here and this mark here. It's -- is it your interpretation that these are two logs?

A Yeah. As I said, if you trace that, you can see clearly the trend go over there and that there is a

parallel mark just nearby what you point out. So that's not fracture. That's just a diagonal two marks.
Q Is it possible that these are not two marks, but that is where the image log is stretched or there was a failure of speed correction?
A No. I think that's -- that's a common features on the image log 'cause we're not interpreted that as picture, and you're not -- you're not going to cherry-picking, say, I want to -- this mark and this mark.
Q Then, still on the same image, can you see the white feature? Let me just find it on the screen. Yeah. Can you see the white feature?
A I can see it. That's also common. For most two marks, they are conductive. On the image log, they're dark straight marks. But sometimes you also see the resistive, which is a white, is also common. So the white is -- the dark mark is because the -- the more -- relatively more conduct mark with the smear by the tool, and the resistivity mark is usually just a partial. It's not really continues like the dark mark. But that caused by the two scratch from more resistive layer, and they move on. So we see that.
Q I assume that that will be your same answer for the white mark here and the white mark here?
A Where?
Q So it is the -- the last one I pointed to you was here.

A Okay.
Q And the other one I was pointing at you is here.
A Okay. I -- so on the image log like that, we only can see it's more resistive. But when we line up with gamma ray and density and we know is that cemented or not. So that went quite easy, actually, when we interpret it.
Q That concludes my questions on FMI.
A S. SVERDAHL: I wanted to add that this -- this example is within the Wabiskaw B and not the confinement strata.
Q Noted.
If we can then go to Exhibit 15.01, PDF page 28, paragraph 108.
I apologize. It does not look like 15.01 is paragraph 108 on page 28. Let me find you the right page reference.
Ah, I see. I was -- it's page 26.
In this paragraph, CNRL says that it has reviewed all of its core and all of its image logs data and it has not identified any fractures within the confinement strata units. The question is: Did you look at information that you did not file?
A Yes.
Q I can provide you with references if I need to, but since the application was filed, 27 new wells were

drilled; is that correct? We can look at them. The one is Exhibit 01.01 at page 28.
A There were 11 wells since the application of the hearing. I believe -- actually, I do have to check. But there -- there were definitely wells that were drilled from the application to the hearing submission.
Q We have it as 16 wells drilled in this -- in this exhibit and then a further 11 drilled in another exhibit. The point is at least 27 -- can you still hear me?
A Yeah.
Q The point is at least 27 wells were drilled in the meantime. You had, in other words, 27 opportunities to do a DFIT if you wanted to but elected not to?
A G. IANNATTONE: We'll just take a huddle here.
A P. THOMSEN: I understand the question to be with all the wells that we've drilled since filing the application, why did we not conduct a DFIT.
So the -- the value with conducting DFITs is to determine principal in situ stress, and that can be used for either leveraging some geomechanical effects for a resource recovery process and/or for caprock integrity or -- or confinement strata integrity. In the absence of significant structural features, we expect the horizontal stresses within a stratigraphic unit to be quite consistent. There are four reasons

that I presented on yesterday as far as why the stress characterization is adequate for the proposed operations, the first being in situ stresses tend to be regionally consistent; the second one being the reasonably present mud-prone strata such as the regional B1 sequence have similar elastic properties, and this is a driver of horizontal stresses; the third one being for the Kirby north field data of starting up 146 horizontal wells, we don't see variable or low fracture pressures; and the fourth one being that I'd previously mentioned we don't have significant structural features such as a karst.

Additional DFITs do increase costs, depending on if it was using an existing cased well or a new wellbore. Could be between 375 to -- $375,000 to $1,075,000. And with what has been requested is a temporary MOP or the purpose of starting up circulation; this is for a short duration and a small volume, and it doesn't warrant the additional DFIT data acquisition. And there's also a concept of proportionality, and the resource or the cost of additional safeguards should not be disproportionate to the risk reduction achieved.

And, with this, it's unlikely to change our requested MOPs, and that is why we did not conduct additional DFIT.

Q I just want to make sure that I understood you correctly. You said that there were no significant geological features at KN08 and KN09 that would indicate that another DFIT is necessary?
A Correct.
Q I would then like to refer you to Exhibit 01.01 on page 55. This is the area where CNRL maps that the mid-B1 mudstone is absent, and that is right -- right at KN09. Do you think that is significant?
A No, I do not believe that is significant.
Q And then if you can --
A It is the --
Q Sorry.
A And the reason for that is the -- the DFIT that's been used to characterize the minimum stress in -- in the B1 really tested the regional B1 sequence. And so it's the -- it's the mud-prone nature of the regional B1 sequence that's the key, and it isn't specifically the 'X' centimetres or -- or metre of a mid-B1 mudstone that's -- that's key. So the -- the important reason is what was tested was the regional B1 sequence.
And so in the -- in the well that has been discussed, CNRL -- Canadian Natural presented on yesterday that did not have a -- a mid-B1 mudstone, it was replaced by a -- quite a muddy tidal channel --
Q I apologize, but I cannot hear you.

A Was it just the last sentence or ...
Q If you could roll back about two sentences, that would be good.
A So the -- the stress characterization is for the regional B1 sequence, and in the well that Canadian Natural presented on yesterday, subject to check, I think it's 1-3 -- yeah, it's the 1-3 example where the mid-B1 mudstone was not present. It was replaced by quite a muddy tidal channel facies. And so, overall, the regional B1 sequence in that well has quite a -- a high mud content.
Q If we go to the next page, that is page 56, and that is where CNRL maps that the A2 mudstone is absent, and I assume that is also irrelevant?
A J. LAVIGNE: Where -- as discussed yesterday, where the A2 mudstone has been removed, other confinement strata still exist in that location, including the Wabiskaw B -- 'D' -- pardon me -- the Wabiskaw D non-reservoir, the -- the basal upper Wabiskaw D heterolithic unit, and the Wabiskaw C. So the concept of confinement strata is that even if individual units have been removed, they work together in tandem to provide confinement.
Q And so my follow-up question to that will then be is: If we have different strata in different sections, would they operate differently under stress?

A P. THOMSEN: What I've been -- what I was trying to communicate earlier with a response is that the regional B1 sequence is -- is present over all of the KN08 and KN09 drainage boxes, and it is dominated -- or it -- it has a high mud content. And so we expect the -- the minimum stress within the regional B1 sequence to be representative over the entire KN08 and KN09 drainage boxes.
Q That is, except for that one well where we don't have the mid-B1?
A The one well -- 1-3, without a -- the mid -- mid-B1 mudstone, has still the lower B1 and the upper B1, and these are mud-prone strata. And, overall, the -- the minimum stress gradient for that regional B1 sequence is representative.
Q If we can then go to Exhibit 15.1, page 29, paragraph 122. Sorry. Just on page 29. It's just -- it's gone over the page. If we could scroll down to page 29.
There, pretty much second line from the top, we -- CNRL says: (as read)
The KN09 and KN09 drainage boxes are directly adjacent to the KN06 and are considered to be in the same depositional and structural setting with each other.
And then Canadian Natural goes on to conclude that:

(as read)

Because these drainage boxes are geologically equivalent, the same monitoring that was allowed for at KN06 should be applied in KN08 and KN09.

Is that correct?

A D. OLLENBERGER: Yes, that's correct.

Q If we then go to Exhibit 20.2, page 59. There's -- in the preamble, we see that ISH says that: (as read)

ISH is of the view that KN06 is not geologically equivalent to KN08 and KN09.

And we see CNRL's response that it disagrees with ISH and reiterates that KN08 and KN09 is similar to KN06; is that correct?

A J. LAVIGNE: Broadly speaking, the stratigraphy between the two adjacent pads is the same. Both have post-B2 incision reservoirs. They're overlaid by the regional lower and upper B1 sequence, separated by the mid-B1 mudstone. Both are overlain by the regional A2 sequence.

As stated in our direct evidence yesterday, over the KN08 and 9 boxes, Wabiskaw D incision has removed the upper parts. We've provided maps that we just looked at that showed where the A2 regional mudstone had been removed. The Wabiskaw D incision does not cut down through the lower B1 sequence, and the mid-B1 mudstone is present over the majority of the KN08/9 pads with the exception of the 100/1-3 wells that we have discussed in some detail. And where the Wabiskaw -- so it is geologically equivalent. In fact, in the KN06 proceedings, we discussed how the A2 mudstone had been removed in one well over that pad, and the KN08 and 9 drainage boxes are immediately to the west where the Wabiskaw D incision is deeper. So geologically they are the same. The difference is the amount of incision at Wabiskaw D level.

Q If we can then go to Exhibit 50.002 at page 8, paragraph 21 -- sorry -- page 8, paragraph 21.

There in the first line we see Canadian Natural recognizes that there are differences in the geological strata present in KN08 and KN09 compared to KN06 and that those differences are relevant to this proceeding. Could you explain this paragraph?

A I believe my previous answer did explain that. The difference is the magnitude of Wabiskaw D incision over the KN08 and 9 drainage boxes as opposed to the KN06 box. They are not different. They just differ in magnitude.

Q So it is your evidence that despite these strata differing in magnitude, their stress response will be exactly the same?

A P. THOMSEN: The -- the stresses within the regional B1 sequence where it is present will be the same. And if I could add to that, the higher mud content of a strata, it leads to a higher Poisson's ratio, which leads to more vertical stress transfer from the vertical stress to horizontal stresses. And there are also some components of the -- the stiffness as well.

So the difference in elastic properties between mud and sand ends up with there being a reliable stress contrast between the underlying McMurray post-B2 reservoir sand and the muddy -- the mud-prone strata. And we -- we focused on the regional B1 sequence for a number of things on the geomechanics evaluations, but really high mud content strata are going to have higher horizontal stresses. And Canadian Natural is -- is highly confident that we have a stress contrast between the post-B2 reservoir sand and the regional B1 sequence of -- or at least 005 kPa per metre. Our characterization points to a stress contrast, the minimum stress gradients of 1.5 kPa per metre.

Q If we go to Exhibit 20.02 at page 12. My apologies. I am struggling with the reference, so I'm going to move on. Then I'll come back to this very shortly.

If we can go to Exhibit 43.02 at page 5. So it is 43.02 at page 5. Pardon me. I'm scrolling.

The second paragraph from the top. You mention

the Wabiskaw D facies, and you include them in your confinement strata for KN08 and KN09. The question is: Why did you not include them in your confinement strata in the KN06 hearing?
A J. LAVIGNE: As we mentioned, the magnitude of the Wabiskaw D incision is -- is greater over KN08 and KN09. And when assessing confinement strata or geological positioning, it's important to look beyond the boxes. And so we look at the units in a more regional sense, and we have looked beyond the KN08 and 9 boxes.
The reason why these two units were not introduced in the KN06 proceedings is that they didn't occur in the thicknesses and mappability that they do over the KN08 and 9 boxes. That's directly a function of the magnitude of the Wabiskaw D incision. So over the KN06 box in one well in the northwest corner, the -- the magnitude of the Wabiskaw D incision was very small. And so it -- it -- those units weren't differentiated and broken out.
Also over the majority of the KN06 box, the A2 mudstone was present, and -- and as we demonstrated in those proceedings, the mid-B1 mudstone was also present. And as we had two regional mudstones, we didn't feel the need to discuss a very thin deposit over KN06 and considering that part of our confinement

strata. But as those units are thicker over the KN08 and 9 drainage boxes, we -- we feel -- and as demonstrated yesterday, over the KN08 and 9 drainage boxes, those two units hold back gas caps, and so they are very relevant in the discussion of confinement strata there.

Q If we can then move on to Exhibit 15.01, page 10, paragraph 31.

More or less in the middle of the paragraph, you -- you mention that the original gas over bitumen decision, or the GOB decision, concluded that Wabiskaw C could not act as a local seal; is that correct?

A That -- that was the board's conclusion. I might add at the time of the original GOB decisions there were very few wells that penetrated into the Wabiskaw C. And because of the lack of information, the variable amounts of bioturbation, and the presence -- the presence of calcites, the -- the board at the time decided to rule that the Wabiskaw C was not considered a -- a regional barrier.

Since that time, we've acquired a lot more well information, and we have observed gas caps trapped beneath it, and so we feel that it does have -- it does have some regional -- at least over the scale of the -- of the drainage boxes in question, the Wab C does

appear to have some capacity for sealing.
Q And that is what you say in paragraph 93 on page 22 of this same exhibit?
A I -- I'd have to see it. I'm not sure.
Q I'm sure we're going to show it to you in a moment. If we could just scroll down to paragraph 93, please.
That is your conclusion that -- that here, the Wabiskaw C does act as a barrier or a local seal?
A I would say the gas caps observed off pad are the strongest evidence that it's a seal.
Q The properties of the Wabiskaw C here, is it different from the properties that the AER considered when they issued the GOB order?
A I think we have more extensive data in the Wabiskaw C now than they did. The unit is the same.
Q Has CNRL approached the AER with this data and suggested that the GOB order should be reviewed and varied as the Wabiskaw C apparently acts as a seal?
A May we just have a moment, please.
No. We have not approached the AER with that.
M. RILEY: I see it is now 22 minutes past 10. The next section that I need to go into will take longer than eight minutes. Might I request that we take the break now and then perhaps return a bit earlier.
COMMISSIONER CHIASSON: Thank you. We can do that.

So let us break now, and we will return at, let's say, 20 to 11, so 10:40, and we'll proceed from there. Thank you.

(ADJOURNMENT)

COMMISSIONER CHIASSON: So before you start again, Ms. Riley, I'll just let you know -- Mr. Lung advised me this morning that it's advisable that we go no later than 12:15 because of room arrangements that we have for lunch on terms of when we need to be out of that room. So just in terms of giving you a -- giving you a -- giving you a time window.

M. RILEY: Thank you. And we will do our best.

My apologies. I just have to scroll in my notes to where I left off.

COMMISSIONER CHIASSON: We'll just -- we are just waiting for Ms. Peddlesden. Oh, okay.

All right. Please proceed, Ms. Riley.

M. RILEY: If we could bring up Exhibit 15.01, Tab 8, at page 194. And if we could scroll down to where the Wabiskaw B1 is identified, the mudstone specifically. Right there. Thank you.

Q M. RILEY: My first question is on this exhibit. How do I see the mid-B1 you're -- if your identifying line wasn't there, how do I see it?

A J. LAVIGNE: I'm sorry. Could you

please -- which well is this? Sorry.
Q If you could just scroll up. I believe it is --
A Yeah.
Q -- the 5-34, but ...
A Okay. When we identify units, we use a stratigraphic datum which restores units to the horizontal. As -- restores them to the way that they were deposited horizontally. And so we use regional markers in offsetting wells, and we correlate -- we correlate that way. So it's finding -- it's finding the level -- the horizontal in this well that's the same as in other wells.
Q So if I were to look at this log, I wouldn't be able to see the B1 mudstone from just this log?
A I think you'd have -- I think you'd -- you wouldn't want to look at wells in isolation. I think you would want to look at them next to adjacent wells to make the correlation.
Q And what do we do when there are no closely adjacent wells?
A I would suggest that over the boxes there -- there are close spacing of wells.
Q If we could then go to Exhibit 15.1, Tab 8, on page 196. If we could just scroll down to the B1 again.
So if neither of these wells show specifically

that there is a mid-B1 mudstone, how do we -- what do we do?
A We -- we integrate with other wells. No one well is used in isolation. This correlates to other wells, other wells that have core, and so we -- we never just use one well. We always correlate to other wells.
Q So if we go to the next one on page 200 of the same exhibit, we can scroll down again, and we see again, really, if it was not for your line, there's no difference between just at the top and just at the bottom of the line. That was the case in the previous three that I've showed you, so I struggle to see if we are correlating wells.
A I don't struggle to see that. Again, we correlate it -- so in this particular well, you can see the A2 mudstone, which is a regional unit which gives us a paleohorizontal quite close to the interval that we're trying to understand, and so we can datum down from that to see where the mid-B1 mudstone should look.
We -- as we've mentioned, the lower B1 regional sequence and the upper B1 regional sequence are very heterolithic, and they -- they have differences in sandstones and mudstones, which affects the gamma ray signature. And there is also thin-bed effects where the gamma tool has a certain resolution, and it has difficulty identifying thin-bed effects.

So, again, that's why we -- we use an integrated approach of other -- other offsetting wells so that we can identify where in a particular well this -- this particular horizon is.
Q So in this case you saw the A2 and then extrapolated from there where the B1 is?
A In this particular case, yes.
Now, in areas of the north -- the north edge of the KN08 box and over the KN09 box, the A2 mudstone is not present, and so in that case we would go up to, say, the top of the Wabiskaw, and we would work our way down to -- to find this particular level.
Q If we go to Exhibit 15.01, where I believe we already are at, page 18, paragraph 68. There the last sentence on the page, the mid-B1 mudstone is highly correlatable in wireline logs. From what we've just seen, that doesn't seem so easy, as you suggest?
A Well, I think that we have a lot of experience over the entire Kirby north area. I might point out that the mid-B1 mudstone is a regional unit that's correlatable over hundreds of square kilometres. So I think that having seen this in several hundred wells, we have a pretty good idea as to where to look, even though there are some differences in the lithologies expressed in the underlying lower B1 regional sequence, the overlying upper B1 regional sequence, those differences

can cause some difficulties in -- in understand --
interpreting that, but, again, we don't look at any
single well in -- in isolation. We apply it over a
broad area.
Q   Is that what you were getting at in para -- in
Exhibit 50.02, page 14, paragraph 43?
A   Yes. What we were saying in that paragraph was that
just making gamma ray API cutoffs is not sufficient
for -- for identifying that feature, and that's --
that's substantiated by seeing the mid-B1 mudstone in
cores where that log signature is -- also does not, for
example, hit 105 API cutoff.
Q   So you didn't really see it in -- in the logs. You saw
it in the cores?
A   No. We don't use either in isolation. We use both.
We use cores -- so just -- and touching on something
that we discussed earlier, every well we drill has an
image log. A subset of those wells are additionally
cored, and so -- and all wells have gamma -- the basic
suite of gamma resistivity logs, and so we use both.
Some wells have all three of those; some wells don't,
and so by leveraging what we've seen in other wells,
then we can make a coherent story.
Q   Good. Let's go to Exhibit 050.003, Tab 6, page 51.
Much smaller, please.
So here we have -- I'm going to call them

"tables", for lack of a better word, and am I correct when I say -- could you just scroll down a bit, please -- that this second image, or table, is an interpretation of the first?
A Yeah. Could -- could we please reduce just a little bit more, please, so we can see the full context of the figure? Thank you. That's -- that's enough.
So in the -- in the up -- yeah. So this is a seismic image that has wells projected upon it that is -- that is out of view in the upper right, and the interpretations on seismic are substantiated with the well logs as well, and so, yes, in the centre is an interpretation of the seismic, but you'll notice it's also driven by the well logs.
Q And I understand that it is difficult to see, but this interpretation includes the log and the seismic from the 10103 well?
A Yes.
Q So if we look at the second -- is it a figure, or is it a table? I'm not sure. I'm going to call it "figure". If we look at the second figure, this green is where you say it's the mid-B1 mud -- well, the B1 region, and then the dashed line is the mid-B1 mudstone?
A Yes, that's correct.
Q So if this includes the 1-3 where we now know that there is no mid-B1, where does this line break up to

show that?
A There's a -- the dashed line there, if you can zoom in, I see the well there. There's a core -- there's a fining upward sequence around the middle of the diagram.
Q Would it help you to have the mouse?
A Oh, sure. This is the 100/1-3 well right here, and so there's a fining upward sequence at the -- in the upper B1 that we've been discussing.
Q But the dashed line that shows the mid-B1 mudstone doesn't break off there?
A Yeah. The dashed line is -- is a correlation through the section. As we've discussed, there -- there's a very small hole in the mid-B1 there as we discussed in the well yesterday.
Q ISH's evidence will be that the mid-B1 cannot be seen on the seismic and on the logs. If that is correct, do you agree that the dashed line is an arbitrary line with no support from any specific data?
A Oh, it's supported by the well data. For example, if you look to the well -- two wells to the left, you can see a very strong break between the lower B1 sequence and the upper-B1 sequence. And so because the mid-B1 mudstone doesn't have a direct seismic indicator, it's obviously extrapolated through here, and it's extrapolated through regions where we don't have well

control as well.
A S. SVERDAHL: I would like to add as well -- if I could just grab the mouse, Mr. Lavigne -- that B1 mudstone is not a resolvable reflector by the seismic here, but we can infer areas where it is not present, such as where I'm pointing here. This is where the Wabiskaw D channel system cuts down, and we can project this interpretation of the mid-B1 against this reflector here and make conclusions as to where the mid-B1 mudstone is not present.
Q If we could then go to Exhibit 050.003 -- we're already there -- and if we can go to page 20. You can just stop it right there.
This is from Dr. Boone's report, and there under the "lack of continuity of a mudstone", he agrees that "mudstones are commonly discontinuous". What is Dr. Boone's response to that?
A T. BOONE: You know, that's just a general statement that any facies can be discontinuous.
Q We have had various discussions -- or we heard, at least, various discussions between VMI and V shale. V shale is a very particular number based on a gamma ray cutoff in your interpretive logs; is that correct?
A J. LAVIGNE: V shale is not --
A S. BARLAND: Sorry. So V shale or volume of shale is not always based on gamma rays. Sometimes

it's based on density neutron log separation as well. So we can have high radioactivity sands that actually look muddy on just purely the gamma ray logs. So quite often it's based on gamma ray, but not always.
Q My follow-up question was: As we understand it, there's various formulas that you can use to calculate V shale. Which one did you use?
A We would have used a combination of both because in the general Kirby north area, sometimes there will be hot sands associated with the reservoir too. So it would have been based on the petrophysicist's -- after a petrophysicist's analysis.
Q Moving on from that --
A Sorry. Just -- just to be clear, the hot -- hot sands are radioactive sands, so they have heavier minerals that contain natural radioactivity like a shale would.
Q CNRL's evidence is that gas comes from -- evolves from the bitumen phase. If gas evolution began slowly at the top, why does the presence of a gradient through the McMurray down to the Wabiskaw convince you that there is isolation?
A G. IANNATTONE: Please repeat the question. Thanks.
Q Certainly. CNRL's evidence is that gas evolves from the bitumen phase. If gas evolution began slowly at the top, why does the presence of a gradient through

the McMurray down to the Wabiskaw convince you that there is isolation? Sorry. I think those two should probably be turned around. The point is if there's a gradient, if there's a pressure difference between the zones and gas evolution begins at the top by slow degradation, why is the gradient evidence of isolation?
A T. BOONE: I'm sorry. Are you referring to GCMS gradient? I mean, what --
Q No. I'm referring to pressure.
A G. IANNATTONE: We'll take a huddle here.
A T. BOONE: Sorry. Are you referring to the figure that I had in my report with the pressure gradient?
Q Yes.
A And so maybe we should bring that up, please, if we can.
Q Can you put your hands on it?
A And I can find that if you'd like.
A P. THOMSEN: It's -- I think it's 50.003. Exhibit 50.003 --
A T. BOONE: I know it's the first report, but I can find that. It's Exhibit 15.01, and I believe it's PDF page 60.
A G. IANNATTONE: Okay. Please repeat the question one more time.
Q CNRL's evidence is that gas evolves from the bitumen

phase. If gas evolution begins slowly at the top, why does the presence of a gradient convince you that there is isolation?
A Just to be clear, which bitumen phase are you referring to, the bitumen in the Wabiskaw B or the McMurray bitumen or the Wabiskaw B bitumen?
Q Is your suggestion that gas evolves differently in the different zones? So in 'B', gas will evolve from bitumen, but in 'D' it won't?
A No. I just -- I'm assuming you're talking about the bitumen in the Wabiskaw B. I just wanted confirmation of that.
Q The question relates to a gradient through the zones.
A T. BOONE: Maybe I will try and explain this chart here. So there's -- there is -- down in the McMurray, there's a pressure gradient, and that's the water gradient. And what normally -- if you're looking for discontinuity between zones, meaning over geologic time -- there's a pressure separation -- you plot the two gradients and then -- between the zones, and you see if they overlap. And so if all the points fell on that -- that hydraulic gradient there, that would at least say that there -- at somewhere -- and it may be well off structure, not immediately there, that they're connected. Okay. So maybe they've got bottom water somewhere that connects these zones, but maybe they're

connected through the column there as well.

But in this case if you plot that gradient and the pressures between the two zones don't fall on the same line, that's evidence that they're discontinuous and that there's a pressure break or barrier between them.

Now, if you start to -- if you have gas on top of bitumen and you start to produce that gas, gas will evolve out of that bitumen -- and you're right. It will start at the top of the bitumen, and the pressure will work its way down through that bitumen, and the gas will evolve out of it and move upwards into the gas. So I'm -- I'm -- it's a bit of a disconnect between your question there -- I realize that -- but I'm -- I'm struggling to understand it, to be honest.

Q No. Thank you. You've been very helpful.

If we can then go on to Exhibit 15.01, PDF page 16, paragraph 2.

So here we see CNRL says that the isopach of the confinement strata is 3.8 metres to 14.3 metres. Do you agree?

A Yes.

Q And then if we go to page 61 of this same exhibit under the geology, the second line from the bottom of the first paragraph, we see Dr. Boone saying that the isopach is 2.46 to 14.32 metres; is that correct?

A J. LAVIGNE: That's what it shows.

Q And then if we go to Exhibit 50.03 on page 9. This is from Dr. Boone's second report. And if we look there in the geography and the stratigraphy -- I'd hope you can see it, but there's a total confinement strata thickness of 13 to 30 metres. And then comes my question this morning when we spoke about the muddy 'D', you mentioned that there's 10 to 12 metres of muddy 'D' over these -- over these strata. So I -- I struggle if the total isopach, which is now 'B', 'C', and 'D', is 2, how did we get to 10 to 12 metres of muddy 'D'?
A G. IANNATTONE: We'll just huddle here for a minute.
A T. BOONE: Let me just explain my part of it there. The 13 to 30 metres -- so, you know, as a reservoir engineer, I was focused on the total thickness, not just the confinement strata that are listed in the table, which are -- are sort of zones within the total package of the confinement strata. And so that confinement strata does contain zones that have lower mud contents that -- that are not barriers per se that were included in the table that was provided by CNRL. But as a reservoir engineer, it's important because steam has to work its way through that, and all that rock has to be heated, and it's also a barrier to conduction between the Wabiskaw B and the

SAGD zone. So the total thickness is important.

And so I asked the -- the geoscientists at CNRL to provide me the total thickness from the top of the post-B2 reservoir to the base of the Wabiskaw B, and that's what those numbers are. And that would include sections of that confinement strata that wouldn't be barriers to steam. But in order for steam to get through them, they would have to be heated as -- you know, by the steam as it migrates through, which all takes time. Okay.

The -- the other number may be -- and I -- and I -- maybe that came from an earlier table, those little numbers; they're just -- there's a minor difference between the -- the final confinement strata thickness numbers that the geologists have been reporting, and I -- I apologize for that.

A G. IANNATTONE: Ms. Riley, can you repeat the second part of the question?

Q My question -- there was only, in fact, one part -- or there was three references and then one question. This morning we spoke about the muddy Wabiskaw D, and you mentioned that it is 10 to 12 metres thick over KN08 and KN09. If we look at those references, then we have a total confinement strata that is at times less than that -- significantly less than that.

A P. THOMSEN: This morning I mentioned the

10 to 12 metres, and that was in the context of the Cenovus example of undrained thermal expansion and a pressure increase in the Wab D -- the Wab delta sand. And the 10 to 12 metre that I was referencing is referring to distance -- or thickness from the top of the post-B2 reservoir to the base of the Wab D delta sand. And there are a number of other items being referenced here, and those would include confinement strata above the Wab D delta sand.

Q If we could then move on to Exhibit 01.01 at page 67.

This is a stratigraphic cross-section through the DFIT wells, and these are the DFITs that CNRL relies on; is that correct?

A That is correct.

Q If we then go and look at Exhibit 15.01, Tab 5, page 108 -- sorry -- page 108.

This is the stratigraphy of KN08 and KN09. And I appreciate that this will be difficult. If we could perhaps go back to the DFIT of the -- or the DFIT stratigraphy, page 67, 01.01. If we look at this stratigraphy, do you agree that there is an A2 mudstone?

A J. LAVIGNE: Yes. The A2 mudstone is present in those wells.

Q And then if we flip back to the 15.01 and we look, then the A2 is not present through the full stratigraphy; is

that correct?
A The A2 has been removed in the second well from the left by Wabiskaw D incision. That's correct.
Q If we flip back to the 01.01, could you compare the Wabiskaw B shape that we see there with the one on 15.01? Are they the same?
A I'm -- I'm sorry. Did you say the 'B'?
Q 'B', yes.
A The 'B'.
Q So look at the Wabiskaw B here, and then compare it to the Wabiskaw 'B' that we see in the stratigraphy for KN08 and KN09. Perhaps it will be -- I'll leave it to CNRL's panel to tell you how to flip so that they can see.
A The -- in this particular cross-section, the Wabiskaw B is not present in the well on the far right from the Jackfish area. Now, if we toggle back to the previous figure, the Wabiskaw B is present in orange that covers the entire section.
Q So these two are not alike or the same?
A These are -- these are different cross-sections from different areas. So the -- the Wabiskaw B is not identical over the entire basin. It's -- it's locally -- in this section, it's continuous. And in the other -- in the previous well log section that we were looking at, it is continuous over the local Kirby

north area in the three wells on the left; and the other well, it's beyond the depositional limit of the Wabiskaw B, where it's encased in the regional Wabiskaw shale.
Q Then for my last geology question, if we can -- well, I -- do we have the transcript on the record I think is the question? I would like to go to page 56 of the transcript, line 16 to 18.
It's page 56. We don't have a 56.
I'm going to try and ask you the question, and if you disagree with my quote, then please tell me, and we will do more work to try and find the reference. You've said that: (as read)
An analysis of overlying confinement strata is critical.
A I'm sorry. Are you referring to a specific quote in this? I'm just scanning it and trying to see that.
Q Line 16. 16 going on 17.
A Yes, I would agree with that statement.
Q My question is: Especially in KN09 there is a very significant portion that does not have any well control. If this is so critical, why did you not drill more wells?
A S. SVERDAHL: Right now we are at AER requirements for well density for KN09. We will consider drilling more wells to evaluate the reservoir

at a later time. What -- we are at current delineation requirements.
Q Very well. Even though we don't have that big zone in the middle, we -- we just don't know anything?
A G. IANNATTONE: Excuse me. Could you pull up an exhibit that shows this big zone in the middle where we don't know anything, please?
Q Can we go to Exhibit 01.01, page 56. If we could then please just enlarge the image.
Do you agree that we see a well to the left side of the KN09 box?
Can I have the mouse? Then I can perhaps show.
So we see a well here, and then we see no wells until here.
A S. SVERDAHL: I'd like to correct that. There is one well in 12-2, which is under the 'N'.
Q What do you estimate the distance is between those wells?
A About 3, 400 metres between those wells, including the well I pointed out under the 'N'. Yeah. My apologies. About 600 metres or so.
Q Very well.
Moving on, then, to the next section of my questions. If we go look at Exhibit 50.002, page 6, paragraph 14. The second-to-last line says: (as read)
Canadian Natural is concerned about the

declining pressure.
Is that correct? This is in the 10-1 well.
A G. IANNATTONE: That's correct.
Q If we can then go to Exhibit 32.02 at page 34. I think I have the wrong exhibit here. If we can go to Exhibit 15.01 at page 34. My apologies.
If we look at paragraph 143, this is where CNRL tells us about the investigation reporting to the 10-1 and that they've submitted it to the AER on May 18, 2021. Remember that date.
If we then go to Tab 29 in the same document, page 350. This is the -- this is the report; right? This is the report that was submitted in May. And I would like to pause there.
It is CNRL's contention that we don't need to worry about the 10-1 well because there was this full investigation into it, the report was submitted to the AER, and the AER was satisfied; there's nothing further to be done here?
A G. IANNATTONE: CNRL agrees that the integrity of the 10-1 well is -- is good, and it also agrees that the data that it's been measuring is valid.
Q If we could then scroll down -- my apologies. Let me just find you a page reference.
If we go to page 358. So in May, CNRL says at current -- if you could just scroll down. After one

year of buildup pressure is now higher than when it was first measured; correct?
A That's correct, yeah.
Q So this is what the AER has when it makes its decision in August, that there's nothing to be concerned about in the 10-1 well? There was no update to this report between May and August?
A There was no update to the report, no.
Q If we can then go to Exhibit 15.01, page 358. And my apologies. If we can go to 43.02. It's not -- sorry. Hang on. My apologies. It is 15.01, 43, page 43 -- 483. My apologies.
Here we have a -- a time line of events produced by CNRL, and here we see that the pressure has been declining since March 2021. So when CNRL provided the report to the AER in May of 2021, the pressure was already declining, but it didn't tell the AER that?
A That's correct, yes.
Q And it also didn't update its report before the AER gave its decision in August 2021?
A Sorry. I missed the question. Could you please repeat that last part.
Q You said that you did not update the report before the decision in August 2021; correct?
A No, we did not update the report.
So the history here of this gauge was the -- that

we saw a very evident pressure buildup that is reflected in, you know, Point 7 and 8 on this plot. Clearly in Canadian Natural's opinion, that is a valve-closing event, but that's only Canadian Natural's opinion. And then at the time we saw a nice buildup, so we thought, Yeah, this is all good -- very good. It looks like in 9 -- Point Number 9, yeah, we pulled the gauges to do the investigative work, the chat log, the casing integrity-type work. We ran the gauges back in. And the date you're referencing was which point?

Q I was not referencing the -- the graph at all.

My point was: In May 2021, CNRL produces a report, tells the AER the pressure is high. Despite knowing that from March pressure has been declining, it does not update its report and leaves the AER to make a decision in August without telling the AER that the pressure is, in fact, declining?

A D. OLLENBERGER: As you can see, up until Point 9, which is in March, the pressure's very flat. So up to that point there was no established pressure decline observed. So I believe that the contents at the time of the report that was sent to the AER remains valid.

Q Sure. And then from there it decreases, but there's no update to the port.

My point is this: CNRL says it's concerned about

this pressure decrease, but it does nothing about it; it does not tell the AER about it?
A The intent of the conditions on the 10-1 are with respect to reporting any potential concerns with flow behind casing or any impacts from SAGD operations. Seeing as the KN06 pad had not began steaming operations until May of 2023, there was no evidence of any sort of communication, and therefore there was no expected need to communicate that to the AER.
Q If we then move on to Exhibit 01.01, page 41. What is the -- in -- in this graph, what is the distance between the injector and the SAGD top? So if we look at your heel, for instance, what is the distance between the injector and the SAGD top?
A S. BARLAND: Looking at it, I believe it's about 6 metres.
Q 6 metres. Okay.
How long does it take for a steam chamber to reach the top of a reservoir?
A Depends on the actual conformance of that well pair. Generally it's in a matter of months, usually, if the sand is very clean and -- and conformance is good.
Q What is the distance between the top of the SAGD reservoir and the Wabiskaw D bitumen?
A Probably around 10, depending on which well you look at, 10 to 12.

Q Then if we look at your map there at the bottom with your proposed heels, do you agree that where those proposed heels are there will be a concentration of heat?

A D. OLLENBERGER: I would say no more than any other portion of the horizontal.

Q How long do you think it will take for the heat to reach the Wabiskaw D bitumen?

A P. THOMSEN: We don't have a prediction included in the record to answer this question. If we could review the -- the PNX and temperature logs that were included in Tab 12 -- I just need to pull up a reference for this, and we could show some field data for that approximate distance. Just one moment while we pull up the reference for this.

A M. SCRIMSHAW: Exhibit 15.01, Tab 12. It's at PDF page 224.

A P. THOMSEN: If we could zoom in, please, on the left-hand pair of red and green images to -- around the area above that 200 degrees C annotation, please. And if we could scroll down. Okay. Great. If we could keep on scrolling down, please.

So some of my colleagues are saying a -- a 15 metre would be appropriate based off of that previous cross-section we were looking at. So if we went up 15 metres from that McMurray non-reservoir base

or the -- the top of the post-B2 reservoir -- just give me a second as I work my way up here. I think that'd be about a 50 to 60 degrees Celsius after four years of operation in this example. That's subject to check with actually getting the measurement on this, but ...
Q Does CNRL acknowledge that conductive heating is a productive -- production mechanism?
A Could you repeat the question, please?
Q Does CNRL acknowledge conductive heating as a production mechanism?
A There is some oil that's mobilized via conduction with SAGD.
Q So in Exhibit 50 -- is that your final answer? Can I proceed?
A Please proceed.
Q In Exhibit 50.002, paragraph 116 on page 34, you agree that conductive heating implies that there's a heat transfer; correct?
A Correct. Conductive heating is heat transfer.
Q Did CNRL include production from conductively heated bitumen in their application?
A D. OLLENBERGER: Can you please clarify the context?
Q So you've been very clear that this application is for McMurray bitumen only. Conductive heating can result in production of Wabiskaw D bitumen. Did you include

that in your application?

A G. IANNATTONE: Just one second, please. Thank you.

A D. OLLENBERGER: Could you just repeat the question one more time, please?

Q CNRL said that they are applying for production from the McMurray formation. The question is: If it is possible to produce Wabiskaw D bitumen through the process of conductive heating, did you include that in your application?

A We did not include any production from the Wabiskaw D in our application, and we feel that such production would be highly unlikely.

Q If we then go to Exhibit 50.003 at page 7. In that paragraph that is numbered "1" on the side, more or less in the middle of the paragraph after the word "Figure 3": (as read)

> Conductive heating of the confinement strata will inevitably occur ...

And then there is the explanation of how it will work, and then at the bottom of that paragraph: (as read)

> To the extent that this does occur, it will result in higher volumes of bitumen production and more optimal exploitation of the total resource.

So we have the statement that it will inevitably happen

and that will result in further exploitation, which does not form part of your application.
A T. BOONE: So you're -- that's out of my report; right? And now the confinement strata consists of McMurray and Wabiskaw. And so it -- it would be very specific to the location, you know, how much production occurred out of the confinement strata and -- and which zone it came out of, but, you know, inevitably you can't stop conduction. I mean, once the steam hits the top of the reservoir, it's there for ten years and conduction continues to occur, and once -- once any bitumen up there is mobilized, it's heated.
Now, the -- the good thing is you get a little bit of oil out of that; right? And the -- one of the reasons SAGD has worked really well is steam actually stops at the top of the reservoir. If steam kept going up there and heated up all this low-quality reservoir, you'd see your steam-to-oil ratios incline -- or, you know, shoot up -- increase significantly, and the whole process would become, you know, less economic for everyone. But fortunately, I mean, steam has been contained to the good sands, and -- and the net result has been -- you know, most projects have very good and very consistent steam-to-oil ratios with SAGD.
Q So we inevitably get this conductive heating. We inevitably get this production from the Wabiskaw D. My

question is: How will you know --
A G. IANNATTONE: No.
A T. BOONE: I didn't --
A G. IANNATTONE: Excuse me.
A T. BOONE: -- say that. I said from the confinement strata there. And it depends on the permeability. Okay? And -- and it's not necessarily the Wabiskaw D. I didn't look at -- to see if there were barriers between -- and I think generally there are barriers between the Wabiskaw D and the McMurray formation steam chambers.
Q If we can then move on to Exhibit 50.002, paragraph 123, on page 35.
This refers to an overpressure event; correct?
A G. IANNATTONE: I think this is that Cenovus example that we talked to earlier this morning.
Q In your opinion, if -- if there was a thermal expansion in the Wabiskaw D, what kind of pressure could that generate?
A Are you referring now to the KN08, KN09 drainage boxes?
Q Correct. If there was a similar event as in this example, what kind of pressure are we looking at? Could it reach 6.5 as in the Cenovus example?
A P. THOMSEN: We have not included a prediction or a model of this within the record to bring up. What we can answer this question with is the

Cenovus example had temperatures of up to 150 degrees C in the Wabiskaw D sand, and with the example that we were just looking at, 15 metres above, we were looking at temperatures around 50 to 60 degrees Celsius. So we would have lower temperatures.
A G. IANNATTONE: I think to answer your question is we don't have a prediction or a model that predicts the pressure in the Wabiskaw D over the KN08 and KN09 drainage boxes due to conductive heating.
Q Very well. Do you agree that steam most often rises to the top of a reservoir and that the overlying strata is heated over time by conduction from the top of the steam chamber?
A P. THOMSEN: Overburdened heat losses will occur via conduction. And what was the second part of the question?
Q Do you agree that steam most often rises to the top of the reservoir and that the overlying strata is heated over time by the conduction from the top of the steam chamber?
A Just one moment.
So our steam chamber development may reach the top of the post-B2 reservoir. In some instances, there are mud beds that can impair the rise of the steam chamber, and so in some portions of our development, the steam chamber will -- will not reach the top of the post-B2

reservoir.
Q I am, in the interest of time, going to skip over a couple of questions, and I'm going to jump to the Long Lake example of CNRL. It's, I believe, in the transcripts on page 117. I believe lines 24 to 26, page 117.
So here CNRL referenced the Long Lake Pads 14 and 15, and you used it as an example of SAGD operations which have an MOP, where the hydrostatic head of the water is near the seismic scale faults in the caprock, and you suggest that Long Lake is an example where this type of operation was conducted safely; correct?
A The purpose for communicating this was this is an area where there is a potential concern about shear failure of the faults through the caprock, and I don't know specifically how far those faults extend within the caprock, but it was an area of concern.
Q Did you know that Long Lake has 18 observation wells in Pads 14 and 15?
A Could you repeat the question, please?
Q Did you know -- did you know that Long Lake has 18 observation wells in Pads 14 and 15?
A I do not know the number of observation wells.
Q I am then going to jump further to the geomechanics topic. I am referring to Exhibit 46.02 at Tab 5, page 32. It's the geomechanical modelling report. And

I'm going to have to ask you for a little bit of help because I only have the acronym here, and I do not, in fact, know what it stands for, "SSL"?
A D. WALTERS: I can speak to that. It -- it stands for shear stress level.
Q Thank you very much.
Can you confirm that in the modelling output you used in computing the SSL it is dependent on the properties that have been assumed for each of the main zones in the modelling?
A Yes, that's correct. It depends on the shear strength properties we assign to each of those materials.
Q Can you show me in your report where you assigned those properties?
A So the Table 1 in the report -- which was corrected, so that's on page -- PDF page 43 -- this table lists the different zones that were included in the model and some of the inputs. The shear strength properties themselves, there was -- was -- were discussed in the text below that table, so two paragraphs down. The paragraph starts: (as read)
Shear strength of the mudstones and mud-dominated confinement strata ...
Q Do you agree that the properties that were assumed for each of those zones was assumed for a homogenous material?

A So the properties assumed for those zones were assumed to be at a post-peak or a residual-strength state and so that accounts for the potential for there to be shear fractures within the materials and is a conservative approach. There were -- there was lab data that was also presented that shows the shear strength of intact mudstone from the area, and the properties that we assumed for the modelling was much lower than those properties. So we used a conservative estimate, but we assumed that for the entire zones, so homogenous through that zone.

Q And we know from the geological evidence that these zones here are not homogenous. They are, in fact, heterogenous?

A That's correct. However, this -- this modelling approach and modelling workflow is much like SAGD. It's something that's very well established and very mature. The first caprock integrity work project that I worked on was in 2002 when the SAGD commercial projects were beginning, and since then I've conducted over 30-plus caprock integrity studies on commercial SAGD projects. It's typical that they don't have the same characterization of the geomechanical material properties in the caprock that you would of the reservoir properties that have been discussed by geology.

Q To be clear, we don't take issue with your approach. We just doubt whether it actually answers the questions that this Panel needs to answer.
A The modelling approach that we take is first developed from a risk perspective. So as you heard in the direct evidence, a lot of the characterization for KN08 and 09 -- a lot of work has been put into looking for risks that could be a risk for containment, which is eventually what the caprock integrity study would look to evaluate over the operational history. So the models that are then developed, which this is an example of that we've just talked about, are fit for purpose based on the risks that have been identified. And geologically, there were very few risks and very low risk identified for containment, as has been discussed, with respect to faults and fractures. The operating conditions are relatively low risk as well in terms of operating pressures and volumes injected at the start-up pressures. So associated with that, the inputs that were used were conservative to analyze caprock integrity, and it was felt representative -- reasonably representative to confirm that we have a low-risk operation, and I believe it showed that.
Q Do you acknowledge that we don't, in fact, have your model on the record? All we have is your report?
A That is correct. This modelling report is on the

record.
Q Could you show us in your report where the maximum confinement strata uplift appears?
A The uplift or the deformations, the vertical deformations are not shown in the report. Just summary plots of the stress levels which are a result of that deformation. The pressure and temperature results that induce that deformation, they are all shown in the report.
Q Could you show us the deformations in your report or the predictions for deformation in your report?
A No. Not in the report. If you would like, I could provide those deformations or deformation plots.
Q The problem that I have is that I have no further opportunity to file further evidence or do anything with that information.
I'm going to stop it here because I'm running rapidly out of time, and I'm going to hand it over to Mr. McLeod.
Mr. McLeod Cross-examines the Canadian Natural Resources Limited Witness Panel
Q A. MCLEOD: Can everyone hear me? Excellent.
All right. So I'm going to start with Exhibit 50.03 at page 3. Now, Dr. , at the top here you say that you re-affirm the conclusions from your

initial report, which I believe is in Exhibit 15.01.
Do you agree with that?
A T. BOONE: Yes.
Q Okay. And you would also agree that in Exhibit 15.0 -- yeah, 15.01, you had recommended a temporary MOP of 6,600 kilopascals; right?
A I -- that was being recommended or being proposed by CNRL, and -- and I supported it.
Q And so when you say that you re-affirmed the conclusions in your initial report that a temporary MOP of 6,600 kilopascals is acceptable, you've actually changed that recommendation now, haven't you?
A I don't believe so, but maybe you could point me to it if I --
Q Sure.
A -- had a misstatement there.
Q Yeah. In -- under Issue 3 there, you say it is your assessment that it's reasonable to permit an MOP of 6,600 kilopascals as requested by CNRL for the purpose of starting up the SAGD wells. And then you go on to say in Issue 4 that it: (as read)

> Is my assessment that solvent injection during start-up phase, as requested by CNRL in Exhibit 15.1, page 47, paragraph 199, should be allowed with a pressure limit of 5,500 kilopascals equal to the MOP without

the allowance for a higher temporary MOP.
So I'm a little bit confused about what -- the temporary MOP that you recommend.
A Sure. And -- and I -- I recognize that there's been a bunch of, you know, confusion. There's different numbers floating around there; right? So the temporary MOP of 6,600 kPa applies to the start-up of the wells. And so this is when they're initially trying to get the wells circulating. And so that's in the very first few days or few weeks of operations. And -- and the challenge, then, is just to get steam circulating because you have this pressure head of water in the well, and you have to overcome that, and you have to overcome your -- your pressures in your flow lines to the plant and whatever else. So that's very early on.
And so then what happens is you get the wells circulating, and that temporary MOP of 6,600 kPa doesn't apply. Okay? Once they're up and running -- I mean, there is a period where it -- as Peter said yesterday, maybe things -- you know, there's a shutdown, and you need to apply it again.
Q So it's --
A But the --
Q It's not just at the start, then. It's -- it's any time that you have to restart the --
A Well there --

Q -- the wells?
A There's a limit on the time period there, but -- so --
Q What is that time limit?
A I -- I'm going to refer to Mr. Thomsen.
A P. THOMSEN: Canadian Natural has modified its requests, as presented yesterday, to a maximum continuous time of 24 hours for use of bottom-hold pressures above 5,500 kPa and below the requested temporary MOP of 6,600 kPa.
A T. BOONE: And -- and so, again, I'll just say now that's during steam injection only. So during solvent injection, which is referred to in Issue 4, I think the proposal has always been that the pressure limit would be the -- the MOP itself, which was originally in the application 6,000 kPa and now has been reduced to 5,500 kPa.
Q So you're suggesting, then, that the temporary MOP would only apply to the times prior to the injection of solvent?
A D. OLLENBERGER: As I stated yesterday, solvent injection will be subject to the long-term MOP of 5,500 kPa.
Q Right. And so when -- when are we going to see the -- the exceedance to 6,600 kPa? Is that before or after injection of solvent?
A It would typically be before injection of solvent.

Under very rare circumstances, there would potentially be a case after an extended shut-in that we would need to recirculate the wells. Due to the heat that would be stored in the wellbore, we would not expect to need to use the temporary MOP at that time.
Q But you've requested to have that temporary MOP extend beyond just the start-up of these wells?
A I don't think that we did do that. Any time that there's solvent in the well being injected, we would not exceed the long-term MOP of 5,500 kPa.
Q I think you might have missed my question. My question was whether you intended to exceed the 5,500 kilopascal MOP at any time aside from at the start-up of these wells.
A As we've stated in our submission, it's very likely that in early SAGD all the injected hydrocarbon would be produced back out of the wells; therefore, if we ever did have to recirculate the wells, it's expected there would be no hydrocarbon downhole. There may be instances where we would have to recirculate the wells. If such times occurred and we could not unload the wells below the long-term MOP of 5,500 kPa, we may proceed to use the temporary MOP; however, this situation is very highly unlikely to occur.
Q And, sir, where in your application was that request for a temporary MOP for recirculation events?

A I think that's covered under the umbrella of -- that we will not exceed the temporary -- temporary MOP for more than 24 continuous hours or 14 nonconsecutive dates. I believe those 14 nonconsecutive days would cover that time period.
Q But at any time during the life of the project you might need that exceedance?
A Potentially, but I would say it's very highly unlikely. Once the wells are on SAGD and the near wellbore area has been conductively heated, unloading the wells becomes much, much easier, and therefore we'd not anticipate to need to use that MO -- temporary MOP to unload the wells and re-establish circulation.
And in our experience, that has never had to occur. We've never had to use the temporary MOP again to re-establish circulation in any of our well pairs.
Q Now, Dr. Boone, was it CNRL that suggested to you that there should be a temporary MOP of 6,600 kilopascals, or did you reach that conclusion on your own?
A T. BOONE: So there was -- well, when I first got involved in KN06, that hearing, the temporary MOP was part of that and -- and was approved for KN06.
Also, if you look in the D 86, the directive for shallow SAGD projects, there's a specific section in there on exceedance of the MOP -- temporary exceedance of the MOPs, and it's commonly granted to most

companies in industry, and there's a procedure there -- in there for asking for permission to temporary -- temporarily exceed the MOP. So it's --
Q So CNRL --
A -- common --
Q CNRL --
A I didn't suggest it, but it's --
Q Okay.
A -- it's common practice.
Q So CNRL suggested to you that it wanted a -- a temporary exceedance of the MOP up to 6,600 kilopascals, and then you concluded in your report that that was the appropriate temporary MOP?
A I concluded that 6,600 was reasonable, yes.
Q Very good.
We'll turn to Exhibit 50.003 at page 22. Can we go back to 21? Sorry. I apologize. It is on 22.
So there, Dr. Boone, you indicate that there's no -- or -- or the risk that you're -- you're considering is -- is whether steam containing no reaction products might escape containment. Can you tell us why it is that you concluded that there would in no circumstances be any reaction products in that steam?
A Sure. So this is early on in -- generally early on in the process that you're starting up the well, and there

isn't a large steam chamber developed yet that would contain reaction products. So that -- that's one point.

But the real key point is if you're going to inject steam -- and the risk here is that you do it above fracture pressure and that fracture rises up into the overlying strata, the steam that you're injecting which has no reaction products because it comes from the plant flows into the fracture, it's at high pressure, there's some leaking off into the formation, and -- and the only possibility is that some of that injected steam makes it up into the strata. But there's -- there's no potential for reaction products to flow into that fracture. Okay? The fracture is at the high pressure, and it's -- it's injected steam, and it has no reaction products in it.

Q All right. Thank you.

I'm going to turn you now to Exhibit 20.02 at page 70. 70, seven zero. Sorry. Thank you.

So from CNRL's response here, is it correct for ISH to understand that it's CNRL's position that bitumen-saturated zones are confinement strata?

A D. OLLENBERGER: Sorry. To clarify, are you questioning whether or not we're implying the bitumen surrounding our SAGD well pairs is confining strata?

Q I'm trying to ascertain whether it is CNRL's position that bitumen-saturated zones act as a -- or are confinement strata.

A One moment, please.

Generally be the mud content of our facies that would be what we would use to determine confining strata. Bitumen at low temperatures would impede flow of fluids. There might be some water mobility in cold bitumen. However, we wouldn't typically classify highly saturated bitumen zones that are heated as confinement strata.

Q Thank you.

COMMISSIONER CHIASSON: Mr. McLeod, just to give you a heads-up, I'd mentioned previously that we have a -- need to have a hard stop at 12:15 because of the availability of the room that we have for lunch, so just to -- to give you an early warning.

A. MCLEOD: Yeah. And perhaps this may be a good time to take a break. I do think that I am going to have to continue for a little bit after lunch just --

COMMISSIONER CHIASSON: Fair enough.

A. MCLEOD: -- due to the length of some of the answers that we've been getting, which we appreciate.

COMMISSIONER CHIASSON: Yes. No. We realize that because our time was off yesterday.

So, Ms. Jamieson.

J. JAMIESON: Thank you.

Mr. Sverdahl, earlier this morning you were asked about three wells, and you were asked to provide the date they were drilled. You were able to give the date of two of those wells but not the third, and you had committed to bringing that information. Do you have it now or ...

A S. SVERDAHL: Yes. It's -- that third well was drilled in February of 2012.

J. JAMIESON: Very good. Thank you very much.

COMMISSIONER CHIASSON: Okay. Great. Thank you. So I'm assuming that, with that, we don't need to check back end of day. You're satisfied with that, Ms. Riley?

M. RILEY: Yes. Thank you. And an undertaking has been avoided.

COMMISSIONER CHIASSON: Thank you. Thank you, all.

All right. So we will break now, and we will look to return back, let's say, at ten past 1. Thank you.

PROCEEDINGS ADJOURNED UNTIL 1:10 PM

Proceedings taken at Govier Hall, Calgary, Alberta

February 7, 2024	Afternoon Session
Cindy Chiasson	Panel Chair
Brian Zaitlin	Panel Member
Meg Barker	Panel Member
William McClary	AER Legal Counsel
Shannon Peddlesden	AER Legal Counsel
Andrew Lung	AER Staff
Denise Parsons	AER Staff
Anastasia Stanislavski	AER Staff
Fahad Hamdan	AER Staff
Maryam Rahimabadi	AER Staff
Susan Harbidge	AER Staff
Maksim Xhaferllari	AER Staff
Felix Chiang	AER Staff
Scott Botterill	AER Staff
Baohong Yang	AER Staff
Elwyn Galloway	AER Staff
J.P. Jamieson	For Canadian Natural Resources Limited

M. Riley For ISH Energy Ltd.
A. McLeod For ISH Energy Ltd.

S. Murphy, CSR(A) Official Court Reporter
S. Burns, CSR(A), RPR, CRR Official Court Reporter

(PROCEEDINGS COMMENCED AT 1:14 PM)
COMMISSIONER CHIASSON: Could we get the door to the foyer closed, please.
Thank you. So, Mr. McLeod, you're ready to continue?
A. MCLEOD: I am ready.
COMMISSIONER CHIASSON: Okay. Please go ahead.
A. MCLEOD: Everyone can hear me okay? Excellent.
DEVIN OLLENBERGER, THOMAS BOONE, LENNON ROCHE, MARC SCRIMSHAW, Previously Affirmed.
GERARD IANNATTONE, JASON LAVIGNE, SCOTT SVERDAHL, DALE WALTERS, XIANG WANG, PETER THOMSEN, SCOTT BARLAND, Previously Sworn
A. McLeod Cross-examines the Canadian Natural Resources Limited Witness Panel
Q A. MCLEOD: All right. I'll start by bringing up Exhibit 50.02 at page 54. All right. All right. So at paragraph 202 Canadian Natural says that it agrees with ISH that the solvent assist start-up

technology is still in the development stage. After testing at KN01 to 08 with positive results scaling this technology up to pad scale at the KN08 and 09 pads is naturally the next step in the technology development process.

And so my question is: What have been the steps that CNRL has taken to go from one well with less than 100 metres cubed injected of solvent to a pad scale test with 350 metres cubed per well with, as I understand it, up to 24 SAGD well pairs on KN08?

A D. OLLENBERGER: Yes, I guess just to clarify, obviously, Canadian Natural has applied to conduct this test on a pad scale. That does not necessarily mean that we will plan on conducting hydrocarbon-assisted start-up on every well pair. More than likely it will be every second well pair perchance, and, secondly, we did do an additional trial at Jackfish for hydrocarbon-assisted start-up, and as far as the volumes that we've requested, as we've listed, the wells on KN08 and KN09 will be longer in length, can be longer in length as applied compared to KN01 Well Pair 8, and therefore we're asking for additional flexibility on the injected volumes.

Q Now, I'm no engineer, but it seems to me that doing every other well pair with the solvent assist must be aimed at determining what -- what the differences are

between using solvent and not using solvent. Am I
right?
A Yes. It would be used to intentionally develop
analogs.
Q So why is it that CNRL has not applied to use solvent
assist on every other well?
A We haven't yet drilled the wells and therefore
selecting candidates at this time would be premature.
Q But CNRL didn't give any indication in its application
or subsequently filed materials that it intended on
doing anything other than using the solvent assist for
every well pair on KN08 and KN09?
A Yes, that's correct. I mean, it is just for the intent
of being able to maintain operational flexibility. You
know, CNRL would like to reserve the right to inject on
every well pair.
Q All right. And in terms of the -- the hydrocarbon that
CNRL intends to use for the purpose of the solvent
assist start-up, in some places I see that CNRL has
referred to it as -- as xylene and other places as
xylene diluent. What is it that CNRL intends on using
as the solvent?
A I would characterize it as a xylene diluent blend.
Q And do you have any detail on -- on the composition of
that or the ratios of xylene and diluent, or ...
A Just one moment, please.

I would say we don't yet have the specific composition locked down ahead of the test. Xylene is a more expensive product than diluent, and 100 percent diluent may cause asphaltene deposition. So therefore we would look to do some further tests potentially to determine the optimum ratio at KN08 and KN09.

Q All right. I'll now turn to Exhibit 40.01. And I'm looking for Tab 8 there. All right. So we'll maybe scroll down to the "Working Experience" there. And maybe just go down a little bit further so we have 2016 to present. Thank you.

Dr. Boone, I've had a look over your résumé, which is now displayed on -- on the screen, and I notice that you worked for ExxonMobil and Imperial Oil for quite a while and -- and did some work with -- with SAGD. But I don't see anywhere on your résumé where you have worked a lot in -- in developing solvent-assists SAGD projects, yet you've commented quite extensively on the solvents at start-up. Can you provide your comments on that?

A T. BOONE: Sure. Why don't we go to the listing of my published papers.

Q Sure. If we can just scroll down.

A Like, the second one there? "An Integrated Technology Program for Solvent-Based Recovery", and I believe you guys included that as one of your aids for cross, and that describes four or five different solvent projects that when I was manager for research at Imperial Oil's research lab here our major focus was solvent technologies, and so I -- I have a lot of experience with solvent.

Q Okay. So maybe we'll turn to AQ Number 1, Tab 2. And we'll turn to page 12.

Now, Dr. Boone, this is the paper that we were just talking about in -- in your résumé, and I think it was published around 2011; is that right?

A Yes.

Q Okay. And about halfway down the page on -- on the page that's on the screen here, you and your co-authors wrote that: (as read)

> A fundamental learning from a long history of pilots at Cold Lake is it is always much more difficult to reliably interpret field results than as is anticipating in the planning stage or can be directly ascertained from simulation models.

Would you agree that that is applicable to field tests generally?

A Yes. I'd say that's generally true.

Q And then later on in that same page, if we can just scroll down -- sorry -- starting at "Another Learning", you and your co-authors wrote that: (as read)

Another learning from experiences that pilots are rarely confined to the planned or design pilot conformance area.

Would you agree that that is applicable to the -- the pad scale test that CNRL is now proposing?

A Well, I think you need to -- so the pad scale test that CNRL is proposing is in the very early start-up phase, and they're injecting solvent, and I think you heard previously with the intent of keeping it within 3 metres of the wellbore. And so in this case, I mean, it is very localized around the well, and -- and there's really no possibility that -- that one well is going to communicate with another.

This paper focuses on recovery processes, and that's, you know, a much longer term. We're going to be injecting much larger volumes of solvent, and the steam chambers have grown to the point where they're connecting between wells, and there's a lot of possibility for fluids moving from one well to the other well.

Q Okay. So you're saying, then, that this is one of those rare cases where a pilot will be confined to the planned or designed pilot area?

A Yeah, and I -- I -- you know, this is -- these are pretty small-scale trials. I'm not -- I don't know whether they would really be qualified as a pilot used

in the sense of this paper.
Q Okay. Now, you go on there to say: (as read)
Additionally facility operations are typically more variable and complex than is anticipated at the planning stage. Recognizing these challenges, high-quality production fluid measurements were performed, not only at the wells where solvent was injected, but also at all adjacent steam-only wells.
You'll agree that the -- the idea that facility operations are more variable and complex than is -- is normally planned is true?
A Definitely, yes.
Q And that would apply to the development of these two pads as well? It will be more complex than it is on paper?
A G. IANNATTONE: If I could take this one, Tom. We do not have any solvent-related facilities for the solvent start-up.
Q Okay.
A It should be thought of as a stimulation to the wellbore, so we inject the solvent, we produce it back, we create some reservoir voidage, and essentially that's the end of it. There's -- it's very simple, quick to do; probably, you know, within a few days of

the injection, the solvent's been produced back so
there is no impact at all on surface facilities.
Q And I'm just going to turn to page 14 of that exhibit. And, sir, you'd agree, Dr. Boone, that with the statement that the transition from a successful pilot phase through to completion of a successful first commercial application is also commonly more difficult than anticipated?
A T. BOONE: Yes.
Q And you'd agree with me that we haven't yet had a -- or, rather, CNRL hasn't yet had a successful pilot phase for the -- as a start-up?
A I haven't reviewed the data that they had on SA start-up.
A G. IANNATTONE: I would agree they haven't had a successful start-up phase yet. That, in fact, is the purpose of wanting to trial it here at KN08 and KN09 so we can advance the technology.
Yeah -- sorry -- my colleague here corrected me. He said that we've had success in the execution, not necessarily in the results, right. So we're -- that's why we're continuing to pilot. We're trying to see if we can get this technology to work subsurface.
Q But essentially -- and as you've -- or CNRL mentions at paragraph 202 of Exhibit 50.002, the intention is -- is to scale the technology up to pad scale; in other

words, do a commercial scale, not to merely test it.
A Yes. That's the intention.
Q All right. I'm going to turn to Exhibit 01.01 at page 77. Now, this was the first plot plan that CNRL submitted in -- in conjunction with this application. Now, I'm wondering if -- if the witness panel can point to where on -- on this plot plan there is any equipment to complete the solvent-assist start-up?
A Just one moment please, thanks.
A L. ROCHE: So, yeah, there will be nothing specific on this plot tied to that. Like Mr. Iannattone said, we come in and do solvent-assisted start-up. We bring in third-party pumping, and we pump them down the wells and maintain our pressure limitations, but as far as flowback, we just use the existing facilities.
Q Okay. And -- and I'm going to turn you now to page 315 of this same exhibit -- sorry -- 316 it must be.
All right. So this is the plot plan that CNRL provided in response to one of the SIRs from the AER. Can you tell me is -- is this the -- the pad that CNRL plans to build on KN08?
A D. OLLENBERGER: This is a typical plot plan for a SAGD pad. Subject to the number of well pairs and final design, it could be altered.
Q And you wouldn't be able to point, then, anywhere on

that plot plan to any sort of equipment that might monitor the injection or return of solvents?

A This pad would be equipped with the typical SAGD monitoring.

Q And I suppose that would be the typical SAGD monitoring that was customary as of the date this was issued for implementation on May 17th, 2018?

A I believe that could be correct. Canadian Natural has not proposed any additional monitoring for hydrocarbon start-up.

Q Thank you.

All right. We'll turn now to the thermal compatibility of wells, and in that respect, I will turn to Exhibit 50.002 at page 57. Now on -- in paragraph 214, we have Canadian Natural's proposal with respect to the 10-2 well: (as read)

> ... to pull out existing equipment, remove the packer assembly, patch the Wabiskaw B perforations, cement from plug back to 15 metres above the Wabiskaw member [and so on].

So I'll ask you to just briefly read that and keep it in mind, and then I'll ask that we turn to Exhibit 50.003 at page 249. And -- and here we have the visual representation of the planned workover for the 10-2 well, and -- and it appears to me that there

might be a little bit of a discrepancy between what was written in -- in paragraph 214, which was that CNRL would pull out existing equipment, remove the packer assembly, and patch the Wabiskaw B perforations to, in this proposed plan, indicating that CNRL will pull existing equipment, drill out the plug, patch the Wabiskaw B perfs and so on. So I'm just wondering if you could comment on those differences and what the intended plan is?
A L. ROCHE: Sorry. Just repeat that again. The variances?
Q Yes. So at paragraph 214 CNRL says that it intends to pull out existing equipment, remove the packer assembly, patch the Wabiskaw B perforations, and so on, and then in Tab 33, CNRL says that it will pull existing equipment, drill out the plug, patch the Wabiskaw B perfs. And so the discrepancy that I'm seeing there and, you know, I'm no -- no reservoir engineer, but the discrepancy I'm seeing is that there's pull existing equipment in para 214 and remove the packer assembly, whereas on the visual representation it talks about drilling out the plug, and my impression is that those are different things?
A Yeah, so I think -- so the first one, pulling out the existing, we would go in, and we'd pull out the existing packer and the coils, and then we would go in

and set a patch. So the drilling out the plug is more part of our commitment to reestablish production after the GOB order is lifted.

Q Oh, I understand. Okay.

So it was just that this proposed plan isn't quite in the order of intended operations?

A That would be correct.

Q Okay. And -- and is it fair to say that based on just this diagram and just paragraph 214, that there's not enough detail at this point to I guess send out a -- a completions crew to do the workover?

A Based on this, no. We have detailed programs that we would share with ISH before executing any operations.

Q Perfect. I'm next going to turn to Exhibit 32.02 at page 27. And can we just scroll down to para 92.

So CNRL has proposed that no wellbore intervention would be required in the 12---34 well because continuous monitoring has been restored there, and at the time of ISH's submission it -- it agreed with that -- that view. But I'm wondering if -- if that monitoring well at 12---34 if it's actually approved to be a monitoring well at this point?

A D. OLLENBERGER: The requirement of the 12---34 well to be a monitoring well has been removed from our approval.

Q And so would it be CNRL's intention then to apply for

approval for 12-34 to be a monitoring well?
A Sorry. Can you please repeat your question?
Q Sure. Sorry. The question is: If -- if the approval for 12-34 being a monitoring well has been removed, would CNRL reapply for that approval?
A The monitoring condition of 12-34 now would be more with respect to the thermal compatibility component, not as an observation well in and of itself. The 12-34 was originally an aquifer monitoring well.
Q Thank you.
I'm going to now turn to Exhibit 43.002 at page 21, and we'll just scroll down there a little bit to the response. Sorry.
So CNRL, at the response, about two-thirds of the way down the screen there, says: (as read)
In the unlikely event of any type of casing breach in the overlying formations of the 12-34 well, hydrostatic flow path would be created between the McMurray and breached upper zone and reservoir fluid transfer would be experienced. Canadian Natural has installed a gauge that measures pressure and temperature which is continuously monitored for a transient response in the data. If any out-of-zone casing breach occurs, the pressure gauge will record a change in

pressure which would indicate a flow path is present. Temperature trends will also be monitored, which would indicate fluids flowing past the gauge. Pressure and temperature data will be used concurrently to detect a casing failure.

Now, Dr. Boone had confirmed that he had not: (as read)

... assessed issues associated with pathways that may involve the wellbores [in his first report.

And had indicated as well in his first report that: (as read)

While tens of kilopascal pressure changes can be resolved by the gauges, it would be very difficult to differentiate from the ongoing pressure changes.

So my question is: What is CNRL going to do in the event of a casing breach?

A P. THOMSEN: We just need to discuss.

Can you just repeat the question once more, please?

Q Sure. The question was: What is CNRL going to do in the event of a casing failure?

A So in the event of a casing failure and if there was -- if there was a casing failure connected to a zone with a different pressure and cross-flow started to occur in the well, we would measure a pressure change associated with that cross-flow, and the response would be to kill the well. And it would be relatively simple to use fluid with -- like, water has a high enough density to be able to control the well, and then we would put together a plan to address the casing failure.

Q And if, in the course of that casing failure, there was hydrostatic flow created between the McMurray and breached the upper zone, what would CNRL do to remediate that occurrence?

A We would likely zonally abandon the monitoring interval. There are other options that could also be considered, but that's the likely course of action.

Q CNRL hasn't done a risk assessment, though, to -- to consider what the appropriate mitigations would be there?

A Canadian Natural has significant experience with monitoring wellbore integrity. We are continuously monitoring wells with steam injection and have experience with -- with casing failures occurring at various times of thermal operations. So CNRL -- Canadian Natural has a response procedure for high-pressure well kills for thermal assets and that can deal with bottom-hole pressure that is far in excess of the KN08 and KN09 setting.

Q I'm going to turn now to Exhibit 50.002 at page 59, and
I'm looking at paragraph 219.
Mr. Iannattone, CNRL will acknowledge that ISH's consent to proceeding with the workover proposals is subject to negotiation and execution of an agreement detailing the respective parties' obligations and rights?
A G. IANNATTONE: Right. I think we're just quoting what they had in their IR response here.
Q Okay. And CNRL acknowledges that that is going to be a necessary step in the process to do these workovers?
A I believe so. That has been the step, I think, that we've taken in the past.
Q Thank you.
A. MCLEOD: Now, just for the -- the Commissioners' knowledge, I believe I've got maybe 10 or 15 minutes more of questions, and we should be able to burn through those relatively quickly.
COMMISSIONER CHIASSON: Thank you for that update.
Q A. MCLEOD: All right. So if I can have the transcript brought up at page 135.
Now, Mr. Ollenberger, I'll have you review lines 3 through 6 of the transcript.
A D. OLLENBERGER: I've reviewed them.
Q And so you'll agree that it was your evidence that a 20-year delay should be anticipated before CNRL and ISH

would be able to produce the gas resource that is subject to the GOB order?
A Yes.
Q And as a result of that conclusion, you think that the discount of 10 percent per annum for 20 years should be applied to the present value of future cash flows?
A That is the assessment we conducted.
Q That was the assessment that CNRL conducted or Mr. Ollenberger?
A We used the 10 percent discounting, correct.
Q But was it Mr. Ollenberger who did the -- the -- applied the discount formula, or who was it?
A I was leading a team that conducted the discounting.
Q Okay. Then perhaps I'll direct this question to you. You're not an economist or an accountant or an auditor?
A Correct.
Q Okay. And can you tell us how CNRL has reported its portion of the gas asset on its balance sheet? Has it applied the same discount based on the delay in production of 20 years?
A It's my understanding that the Kirby Upper Mannville II gas pool is not on our reserve books.
Q You haven't recorded it on your reserves at all?
A Subject to check, I believe because it's shut in, it would not be considered proven reserves.
Q Can I get an undertaking for you to review CNRL's

records to confirm whether the gas resource under the Upper Mannville II pool is -- is on the reserves, and if so, the value that it's recorded at?
A Yes.
A G. IANNATTONE: I think we can check to see if it's on our reserves. With respect to the value, I'm not sure that that's relevant here because -- anyways, I don't believe it's on our reserves, but I'm not committing to the value at this point in time.
Q Well, sir, I would suggest to you that given that CNRL takes a position that the evaluation that ISH has assigned to its gas resource is wrong, that it only -- it would be fair that CNRL tells us how it values the same gas resource.
A I wouldn't say that Canadian Natural is saying that ISH's valuation is wrong. All we're saying is that -- and maybe what we should do is pull up that IR question where Canadian Natural asked ISH a series of questions so that we could better understand how they came to their value, and I -- I have the number here.
Q I mean, the -- the value that ISH came to was accepted by CNRL subject to this 20-year discount?
A That's -- that's correct. We've used their values, and we just discounted them because it was unclear to us what their values meant because the only reference to timing there is it said that it had an effective date

of January 1st, 2024. There's no detail, even though we asked for it, in terms of when did the production start and some other questions. So we're making -- we just don't know. We just don't know. So we -- that was our approach.

But going back, we typically don't publicly disclose reserves and values of reserves at this minute detailed level. We will confirm if we have reserves booked or not, and we'll report -- report back, but I don't think it's our corporate policy to talk about what kind of value we have in a public forum about our reserves, unless we want to move this part of the hearing into a confidential portion, but I'm certain -- certainly wouldn't support that.

COMMISSIONER CHIASSON: Is it confidential to speak to, if it's on your reserve report, the method that you would use for assessing future value?

A G. IANNATTONE: No.

COMMISSIONER CHIASSON: Because it seems to me that that's what -- if I understand correctly, Mr. McLeod, that that's what you're getting at, is what's the methodology that they would use.

A. MCLEOD: Yeah. That's correct. I am getting at what is the methodology, yeah.

A G. IANNATTONE: Yeah.

COMMISSIONER CHIASSON: Because I think the Panel

would be interested in that information.
A G. IANNATTONE: Okay. Yeah. No. Methodology is fine. The exact dollar value is not, so ...
Q A. MCLEOD: And --
COMMISSIONER CHIASSON: So just so that we're clear, then, for the undertaking, so it's that CNRL will check to assess whether or not their interest in the gas in the upper -- the Kirby Upper Mannville II pool is on its reserve reports and, if so, what's the methodology that it's used for determining the future value.
A. MCLEOD: For determining the present value.
COMMISSIONER CHIASSON: Present value. Okay. Thank you. And future value or --
A. MCLEOD: I mean, the -- the future value can derived from the present value --
COMMISSIONER CHIASSON: Okay.
A. MCLEOD: -- based on the discount. So I'm only concerned about the present value.
COMMISSIONER CHIASSON: Okay.
A. MCLEOD: Yeah.
COMMISSIONER CHIASSON: Thank you.
Got that, Mr. McClary? Lovely. Thank you.
UNDERTAKING 1 - For Canadian Natural Resources Limited to check and assess whether or not their interest in the gas in the Kirby

Upper Mannville II pool is on its reserve
reports and, if so, advise the methodology it
used for determining the present value
(Fulfilled on Page 405)
Q A. MCLEOD: Now, one further question on
that --
A G. IANNATTONE: Sorry, Commissioner Chiasson.
In terms of timing, those reserves are in another group
that we don't look after, so is it okay if we report
back by noon tomorrow?
COMMISSIONER CHIASSON: That -- that should work fine.
I think we will have to see once that comes back in
terms of whether or not ISH may have a need to explore
any further on that.
A. MCLEOD: Yeah.
COMMISSIONER CHIASSON: We'll be open to looking at
that --
A. MCLEOD: Yes.
COMMISSIONER CHIASSON: -- that timing.
A. MCLEOD: Yeah. That -- that's
agreeable.
COMMISSIONER CHIASSON: Okay.
A. MCLEOD: Subject to the ability for ISH
to potentially question on it.
COMMISSIONER CHIASSON: All right. Thank you.
Q A. MCLEOD: Now, one final question on

that -- and I understand that CNRL likely has a very robust accounting program for its -- its proven reserves, and so my -- my question is: For proven reserves, what is the effective date that is used for the valuation of the present value of a proven resource?
A G. IANNATTONE: Is that proven producing reserves or proven undeveloped preserves?
Q Both.
A That is our annual year-end date, so typically December 31st of the prior year.
Q Perfect. Thank you.
Next I'm going to turn to Exhibit 50.002 at page 44.
Now, here I see on the -- the fourth row of this table that CNRL estimates the cost of a DFIT on KN08 or 9 as $1,075,000. If we turn to page 53 of this same exhibit, in paragraph 197, CNRL says that the cost of DFITs on three intervals over the KN08 and KN09 drainage areas would be approximately $375,000. You'd agree with me the difference between those two is the cost of drilling a well?
A D. OLLENBERGER: Yes. The 1 point -- sorry -- the 1 million 75 -- I'm having trouble with the system here. The 1,075,000 total cost estimate is 375,000 for the DFIT execution itself and 700,000 for a cased hole

strat.
Q And in its latest submission, CNRL has already agreed to drill an additional gas monitoring well in KN09; right?
A A future well, yes.
Q So it's not actually accurate, then, to suggest that a DFIT would cost over a million dollars?
A I believe it will still cost over a million dollars all in.
Q But you're going to be drilling a well anyways. You're going to spend that $700,000 either way, so the added cost to the DFIT is only $375,000.
A I would say that if that future well on KN09 was in an ideal location to conduct a DFIT, which we're not currently certain, that it potentially could be used for a DFIT and then converted to a monitoring well.
Q All right. So if you've overestimated the -- the cost for the DFIT, fair to say that you might have also overestimated the time delay that might occur as a result of conducting a DFIT?
A G. IANNATTONE: So -- so, first of all, obviously that we only have winter access here; right? So we have to drill a well and we have to conduct a DFIT in the same winter season. That is easier said than done. A good example is this winter, for example, where we had record highs in January, so we couldn't

even move drilling rigs in to start our strat program until later on in the month of January. So there's no guarantees.

I guess, more importantly, we don't think that an additional DFIT is going to change our requested MOPs, but -- so we just can't -- we just don't know if it's going to be a time delay or not.

Further, what we do with the information once we can -- if we did do an additional DFIT, what would we do with the information? We'd have to either reapply, reaffirming our MOPs, and is that process open to consultation? If it is, all bets are off in terms of timing. So we cannot sit here today and say that doing an additional DFIT would not delay the project.

Q All right, sir.

A And I think one of the points that I made is that before we commit to drilling a pad, we pretty much have to have certainty that we can execute under our conditions. So until we have that, the corporation will not commit.

A T. BOONE: Sorry. Can I just add one comment here? I see on paragraph 197 it refers to my risk assessment and the maximum consequence being less than $1 million. But -- but the DFIT specifically refers to Risk Number 2 where the maximum consequence was a hundred thousand dollars or less. So if -- if

you're just -- we need to read that correctly. So
that's why the DFIT being much more costly than the
consequence itself makes it not justifiable.
A G. IANNOTTONE: Yeah. The last --
Q Based on your assessment of -- of the -- of the risk,
which was based on information that was conveyed to you
by CNRL; right?
A T. BOONE: No. I -- I assessed the risk
of fluids migrating during start-up into the Wabiskaw B
gas zone myself.
A G. IANNATTONE: I would like to add an
additional point that was brought up by my colleague.
The other prerequisite for DFIT is -- is that we need a
vertical wellbore. Most of our strat wells are
deviated. So likely we'd have to plan and design a new
wellbore.
Q All right, sir. My last question for you -- if I heard
you correctly there, you said that it was unnecessary
to do a DFIT because regardless of the results, your
MOP is not going to change. So CNRL is -- is going to
take new information and not change its position?
A P. THOMSEN: Canadian Natural will use all
information available with the -- the assessment and
the future operations. Previously I'd mentioned
proportionality, and when you consider the use of the
temporary MOP, it really is for the first time -- to

initiate its potential use for the first time to
initiate circulation, and if it was used, it would
likely be for a couple hours with a -- with a volume
that's well under 180 cubic metres. And so even if
there was some unlikely result of having a -- a reduced
stress, yes, we would -- we would continue to request
and justify the temporary MOP of 6,600 kPa for a
start-up, and that's in part it's such a short duration
and a small volume that's injected.
A G. IANNATTONE: The -- the last point, as --
as we've said, we've lowered our long-term MOP from
6,000 kPa to 5,500 kPa, and that is a mitigation, and
that is a -- an additional reason why we don't feel
that an additional DFIT is -- is required because
we've -- we've modified our request.
Q Thank you.
A. MCLEOD: Subject to questions on the
undertaking that was given, those are my questions this
afternoon, Commissioner Chiasson.
COMMISSIONER CHIASSON: Thank you, Mr. McLeod.
So you look like you're about to say something,
Ms. Riley. No?
M. RILEY: Absolutely not.
COMMISSIONER CHIASSON: Okay. Thank you.
All right. So what we would do next is -- what
would be next on our schedule is questions from the AER

staff and Panel. We will take a short break just because we need to check in with our team, so -- but we anticipate it being no longer than ten minutes, if that. So we will break and be back shortly.

(ADJOURNMENT)

COMMISSIONER CHIASSON: Okay. Thank you for your patience. So, witness panel, what we will do is we will be starting with -- Mr. McClary and Ms. Peddlesden will be directing questions to you that have been formulated by the staff team who are supporting the Hearing Panel. Once they are finished with those questions, then the Commissioners, the Hearing Panel, we may have questions for you as well, so just so that you know it's proceeding.

So Mr. McClary is going to kick things off.

W. MCCLARY: Thank you, Commissioner Chiasson.

Alberta Energy Regulator Legal Counsel Questions the Canadian Natural Resources Limited Witness Panel

Q W. MCCLARY: As Commissioner Chiasson has said, my name is Will McClary. I'm legal counsel here at the Alberta Energy Regulator, and I'm going to be asking a few questions today on the subject of the Fustic papers and the gas chromatography mass spectometry -- thank you -- or what I will call it, thankfully, for the rest of the afternoon "GCMS data", and I want to explore that a little bit because we had some questions.

We might do a bit of shuffling on this bench just because we don't have enough room here to accommodate our subject-matter experts who are helping us with the questioning, so I apologize in advance if that's disruptive. We'll try to do it quietly, but once I'm done my questions, we'll get a few more SMEs up here, and Ms. Peddlesden will continue with the questioning.

So I pose this to the entire witness panel, and you can identify who is best suited to respond and we can proceed from there, but the general understanding that we have at this point is that the Fustic paper from 2011 that was submitted at Exhibit 43.002, I believe it's Tab 7A, forms the basis of CNRL's interpretation of the GCMS data that's been presented so far.

So to the witness panel, I guess, is that correct? And then who is best suited to answer further questions on the subject?

A S. SVERDAHL: Mr. Barland is the best to take that.

Q Thanks.

Mr. Barland; is that correct?

A S. BARLAND: Yes. So most of the industry usage of GCMS in the oil sands reservoirs is based on

those fundamental or pioneering papers on -- on the use of the analysis of oil compounds and the -- plotting them versus depth.
Q Thanks. Now, when you say "oil compounds", what do you mean?
A So crude oil or bitumen is made up of multiple different hydrocarbon compound classes, and what we do is some certain members of those oil compounds and then plot them versus depth to determine their gradients.
Q Thanks. So my understanding from having reviewed -- and I guess -- sorry -- also going back, and I will slow down, I promise, reporters. Going back, you referred to two papers, I believe, or "papers" plural. Is there another paper in addition to the Fustic 2011 paper?
A There is also the Fustic 2013 paper that was submitted as well in the IRs from the AER to CNRL.
Q Thanks. And that's -- you're correct there; that's Fustic 2013. I'll refer to it as -- and it's Exhibit 43.002, Tab 7B.
So in addition to those two papers, are there any other papers that CNRL relies on or any other kind of scientific methodologies described elsewhere that would be relevant to our consideration of the analysis?
A No. I don't think so. I think the gist of it is contained in the Fustic. I would add, though, that

that's been over ten years since both of those papers were published, and our sampling density as well as the probable interpretations of barriers and baffles may have been influenced by real-world industry knowledge from our own other producing assets as well since then.
Q Thanks. So my understanding, then, of that evidence is that you're saying there's -- there are subsequent -- subsequent experience that CNRL has had in this area of interpreting GCMS data that supplements the -- what's presented in Fustic 2011 and Fustic 2013?
A Correct.
Q Thanks. That's helpful.
Have you presented kind of the basis for that analysis to us anywhere in the materials?
A So in the reply submission -- I can't remember what the exhibit number is. I can get that.
Q I believe it's 50. Five zero.
A Yes. Yeah. There is one example that I -- I brought in from CNRL's Jackfish project. This was -- I used to work at Devon Canada, and we did a -- we did a CSBG technical conference presentation in 2019 that was published as well, and that case study on the use of GCMS -- this one example was from that -- from that technical conference presentation.
Q Okay. But the underlying principle, I guess, from Fustic 2011 and 2013, is that still sound?

A Yes.
Q And, in general, I guess, the description of the Fustic papers of that method -- which we'll go into a little bit more in detail in a moment -- that is still generally sound; it's not contradicted or anything?
A Not to my knowledge.
Q Okay. Now, if I could please pull up, I guess, Exhibit 43.002, Tab 7A or page 147 of the PDF. Just, yeah, the next page there, please, and then a little bit further down, please, there's a paragraph that begins -- or contains the phrase: (as read)

The continuity of biodegradation-susceptible aromatic hydrocarbon concentrations.

W. MCCLARY: It's the fourth line in the second paragraph. If you could just maybe highlight that for Mr. Barland with the cursor or select it.
A Yeah. They just made it a little bigger.
Q W. MCCLARY: So this is the abstract for the paper. Can you -- can you see it? I can read it as well if you prefer.
A (as read)

Continuity of biodegradation-susceptible aromatic hydrocarbon concentrations measured through vertical profiles of a reservoir were used to determine siltstone-prone intervals observed in log and core acted as barriers or

baffles to fluid flow over geologic time.
Q And then the next sentence is: (as read)
Integration of the bitumen molecular composition data with geological cross-sections fosters predictions of the lateral extent of the identified barriers.
Is that -- that's what we're talking about?
A Yeah.
Q And now is that a fairly good summary of the Fustic method, the 2011 Fustic method?
A I would say so, yes.
Q Is there any kind of important supplement to that that we would want to add based on the intervening years?
A I would -- I would say the only thing I would add to that would be our interpretations of some of the forward-stepping or upwards-increasing steps in the -- in the geochemical or the oil-compound concentration profiles. So the paper -- or the presentation that I referred to earlier that I did at a previous company examined these forward-stepping changes, upward-increasing changes, and found that they were barriers to steam as well.
Q Okay. So, I mean, we can get into that in a bit more detail in a moment, but just to confirm, when you say "upward increasing", you mean that the relevant concentration of the polycyclic aromatic hydrocarbons,

or PAHs, that are being measured in this method is increasing --

A As you go up.

Q -- as you go up as opposed to going down, which is what's described by Fustic?

A Yes. Correct.

Q So now that -- I think that response to a question that was raised yesterday about the direction of different offsets?

A Yes.

Q And I intend to explore that in a bit more detail later on, but there was a phrase you used yesterday that I wanted to check in on and ask you about, and I believe it was the "equilibration of compounds over geologic time".

A Yes.

Q Could you explain a little bit more in depth what you mean by that?

A So as the oil charges the reservoir, it's light. As it biodegrades, it becomes heavier and heavier, so there are buoyancy effects as the oil degrades. It also creates biogenic methane and so that will rise to the top of the reservoir through the oil and/or bitumen and all aid in its movement. So if you have a very connected column or a very easily mixed column of hydrocarbons or slowly degrading -- biodegrading

bitumen, that mixing process will create that diffusion across barriers or baffles. If you don't see that or you see two separate curves, that means there was something in between them that prevented that mixing.
Q Now, when you say "mixing", can you explain a bit more in detail what you mean by "mixing"? Is it your evidence that the -- the compounds themselves would diffuse across the zone or, you know, we're talking about molecules within substances -- like, what is mixing? What is equilibrating in this?
A So, yes, it's molecules slowly diffusing.
Q And so if you could imagine a theoretical bitumen molecule that's at one point in the zone, is it your evidence, then, that that molecule would move -- or not a molecule, like a small amount of bitumen?
A Portion.
Q A portion of it?
A If the buoyancy or changes in oil/water contact may force it there, yes, it could. This is very slow, though. This is very slow.
W. MCCLARY: So if we could pull up please Exhibit 43.002 at Tab 7B or PDF page 196 or -- sorry -- page 203. 203. And now about midway through the left side -- stop there, please.
Under "Reservoir Charging" and "In-reservoir Fluid Mixing" -- maybe actually just scroll down a little bit

more, please. There that's the paragraph I'm looking at.
Q W. MCCLARY: And now, Mr. Barland, could you please read that for us?
A Under the "Reservoir Charging" and "Fluid Mixing".
Q Yeah. Is that large enough? Or I could read it as well if it's easier.
A (as read)

Fluids in petroleum reservoirs are constantly mixing with a tendency to attain equilibrium [from several different papers]. Biodegradation or physical leaking results in some fluid components being removed from the reservoir, whereas other components such as methane and CO2 are generated in the reservoir as byproducts of biodegradation. [Again, more quotes from different papers] These processes are poorly documented in studies dealing with the Athabasca oil sands deposits, but it's clear that mixing times with their viscous fluids may exceed reservoir age.

Q Does that contradict what you just told me about bitumen moving or molecules moving within bitumen in the reservoir to reach equilibrium over geologic time?
A So -- so I think that actually confirms it.

Q Can you explain how?
A So if fluids are constantly mixing with a tendency to attain equilibrium, that's what I was describing.
Q Sorry. I mean the last sentence of that paragraph in which it says that: (as read)

> The processes are poorly documented in studies dealing with Athabasca oil sands deposits, but it's clear that mixing times with these viscous fluids may exceed reservoir age.

A I don't know that it -- it discounts that entirely. I would say that the reservoir age in the -- in the McMurray formation that we're looking at here is probably in excess of a hundred million years. The oil would have charged it afterward. Being -- being "poorly documented" means that they're, you know, they could be right or they could be wrong.
Q I'm really specifically looking at the part of the phrase where it says: (as read)

> But it is clear that mixing times with these viscous fluids may exceed reservoir age.

I'm trying to understand whether that contradicts the idea that -- that there is mixing as suggested by the concept of equilibration of the chemical compounds.
A Okay. So what I -- what I would say or respond to that with is that the fluid was not always as viscous as it

is currently. The process of biodegradation is still occurring today in the -- in the reservoir as well as an outcrop in the McMurray formation north of Fort McMurray. So anywhere you have -- anywhere you have an oil/water contact still, you would still have that bacteria because the -- the sediments haven't been sterilized; they haven't been buried greater -- to greater than 80 degrees Celsius.

So it -- it's still an ongoing process because the oil initially charged at light API levels; the mixing would have been easier then. So mixing now, yes, very, very difficult to mix bitumen, but when the oil was charging, it wasn't bitumen. It slowly was converted to that.

Q Understood. Thanks. That does clear that up for us.

Now, I guess taking the -- the combination of the two papers, Fustic 2011 and 2013, my understanding of the papers is that, you know, they've -- they've conducted the GCMS analysis on the number of wells and identified a whole bunch of compounds that are relevant and interesting for the assessment that they're trying to conduct. Broadly speaking, the compounds that we're interested in for the purpose of the analysis conducted on the wells for this hearing relates to polycyclic aromatic hydrocarbons; correct?

A Yes.

Q And based on, again, those papers, it -- it seems as though there are some PAHs that are susceptible to biodegradation at a greater rate or, you know, over slow -- like, shorter time periods, we'll say, than other PAHs; is that correct?
A Yes.
Q And in Fustic 2013, they identify a number of PAHs which act almost -- that are, I guess, effectively for their analysis not as susceptible to the biodegradation and therefore show a consistent concentration in a vertical profile?
A Yes. Yeah. So they would -- they would be a straight up-and-down line. Usually those are the heavier ends. You can think of -- you can think of the oil over the biodegraded bitumen as the food of the bacteria. That's essentially what it is. And if there was a party underground, the first thing to go would be the chips and the pop and the really tasty stuff; the last thing to go would be the broccoli. The heaviest ends, that's the broccoli.
Q And in this case, my understanding is the subset of PAHs that we're interested in, the chips and pop, are kind of carbon molecules that are slapped on to these PAHs?
A Absolutely.
Q And the broccoli --

A And the easiest bonds to break.
Q Yeah. The broccoli is the -- the leftover kind of base PAH itself --
A Yes.
Q -- that gets eaten last?
A The -- the longer chain ring carbon structures.
Q And then if we're extending that analogy, would it be consistent to say that these -- these other markers that showed a consistent profile through -- through a certain formation that don't show a -- or a curve of biodegradation, those are kind of like something you wouldn't even think about eating at the party?
A That could be your shoe.
Q Yeah. Somebody's shoe. Thanks.
So now are there different shoes?
A Oh, yes. Yes.
Q And do those shoes tell us anything about the oil?
A So -- so the longer chain, bigger molecules that are harder for the bacteria to -- to biodegrade or to eat, sometimes you will -- you will use them to determine oil providence. You can -- you can also use different ratios of -- of certain longer chain ones, like 9 versus 1 methylphenanthrene to determine biodegradation index. That's a -- that's a commonly discussed result in both Fustic papers.
Yeah. Pristane/phytane ratios determine oil

providence usually. That's kind of one that's commonly used in both of these papers. So the longer chain ones do have their uses, generally not -- because they don't move as you plot them with depth, it's not useful for determining barriers and baffles. So you have to move to a shorter chain or -- or lower atomic weight molecules that you can actually observe change with depth to determine those barriers and baffles.

Q Thanks. Now, going back to the shoe analogy, as it were --

A Okay.

Q -- I believe you said at the beginning of your answer just there that the shoe print, we'll say, can determine providence or can be associated with providence of the oil; is that correct?

A Yes.

Q Would there be any other anticipated chemical differences between oil with different shoe prints or that has different providence?

A Yeah. There -- there probably is. Again, I think some of what's discussed in both papers discusses that a little bit. In general that's probably not as -- as useful to a working geologist or determining barriers and baffles than the -- than the molecules that -- that you can observe the barriers and baffles in.

Q Thank you. So --

A Sorry. The compound classes, I guess.
Q Thanks. Sorry for stepping on you there.
Just to confirm, though, then, it wouldn't be the case -- or feel free to correct me, but it would not be the case that oil with a different shoe print might affect the interpretation of the -- you know, what gets eaten first, whether it's the pop or chips, or the curve that we see in response to the concentration of the PAHs that do biodegrade?
A So, yeah, I suppose I should clarify a little bit. If there were multiple charge events of differing -- at differing times of different providence, that might obscure things. We generally don't see that or the -- the Fustic papers, along with a few other examples of papers from, say, Dr. Jennifer Adams or Dr. Barry Bennett do not see that in the McMurray or the Mannville group as a whole. In general, Wabiskaw oil providence looks like McMurray oil providence.
Q So did you look for it in this case? Like, did you take the samples that you would be able to tell what the shoe prints are for the -- the oil through the column?
A Yes. All of that gets output from the -- from the mass spec spreadsheet we get of -- of every aromatic hydrocarbon individually and then some to plot. I have looked at MAS versus TAS or the tricyclic terpanes

versus the pentacyclic terpanes, and the providences look very similar.
Q For the wells in question for this hearing, you've looked at -- you've conducted the analysis or plotted the shoe prints -- and I'm sorry that I'm not going to be able to say which terpanes they are, but you plotted the shoe prints --
A Yeah.
Q -- for all of the wells in question?
A I would -- probably five of the six.
Q Okay. And are those plots anywhere in the materials?
A No. We didn't submit any of those plots.
Q Is there a reason why?
A They don't show anything in terms of barriers and baffles. So I didn't feel like they were relevant or -- or useful.
Q Thanks. I think that about does it for the shoe print discussion. Now, I'd like to move over to the pop and chips and eventually get to the broccoli.
W. MCCLARY: So if we could go, please, to -- still keeping in Exhibit 43.02 and go to page 177, please.
Q W. MCCLARY: So I'll save you having to look across the room, and I'll just read this out, and the word we're looking for is: (as read)
Anaerobic biodegradation occurs within the

oil/water transition zone.
So I think it might be ... It's about halfway through the paragraph under that -- with -- under the heading "Bitumen Quality Characterization".
A Okay.
Q And it says: (as read)

> Anaerobic biodegradation occurs within the oil/water transition zone where diffusion of biodegradable hydrocarbon components through the oil column to the active biodegradation zone is responsible for observed vertical compositional gradients.

Now, can you describe for me please what a vertical compositional gradient is that you're looking for in this analysis?
A So that's exactly what -- what the plots describe in all of the submitted GCMS plots of CNRL's or of -- of ISH's experts as well show that vertical compositional gradient. So generally the -- the most -- or the least biodegradation occurs at the -- closer to the top of the reservoir, and the most occurs near the oil/water contact.
Q Thanks. Now, when it says "gradient", what exactly are you looking for to establish a gradient?
A That change versus depth, right. So lots up here, less down here near the oil/water contact.

Q And now when you're trying to establish a gradient for your analysis, you know, you've just described two points on a plot. Do you -- how many points do you need? Like, what are you looking for in terms of establishing a trend or a gradient or a curve?
A So -- so in general you always need three points to make a line, minimum, right? So we would -- we endeavour to take a sample every -- probably 75 centimetres to 2 metres. If we -- if we think there's nothing to sample, there's no facies change or something we're interested in, we -- we might increase that sample density just a little bit or -- sorry -- decrease that sample density. So we'd go to a sample every 2-and-a-half metres. But by and large a lot of the Fustic paper -- and, you know, that was pioneering work 12, 13 years ago. They go -- they sample every 4, 4-and-a-half metres, so our sample density has increased just because we're looking for small -- smaller changes sometimes, especially in areas that have more mud, so you -- you just have less bitumen to sample sometimes.
Q Thanks. And when you say "sampling", what exactly are you sampling?
A So we sample the core. We actually take a -- a spoon or a garden trowel, and you physically carve a little piece out of the core as clean as you can get it and

put it in a Ziploc bag and off it goes to Schlumberger.
Q That answers that question. I was going to say -- because yesterday you referred to Schlumberger as running the analysis, but it is, in fact, CNRL that collects that sample?
A We -- yes. We -- we would go and collect it, or the coring lab that we're -- core analysis lab sometimes will take our samples on brand-new cores.
Q Thanks. I'm going to explore that a little bit more in detail after we talk about the papers, we'll get through that, but thanks for that.
W. MCCLARY: Now, if we could go to page 180, please, in the same document, and it's in the left column, about halfway down. And I'm looking for the "biodegraded reservoirs". Oh, yeah. 180. There. You can stop there. Thanks.
A Yeah.
Q W. MCCLARY: And the statement is: (as read)

> In biodegraded reservoirs such as those in the Athabasca oil sands, the systematic removal of more biodegradation-susceptible compounds of the oil/water contact creates downward decreasing concentration gradients in an oil column.

And then I believe it goes on later on this page to say

"the susceptibility" -- is that in the same paragraph?
A Yeah, I think it is.
Q Yeah. (as read)
The susceptibility of alkylnaphthalenes to biodegradation decreased in the order: methylnaphthalene, C1N; dimethylnaphthalene, C2N; trimethylnaphthalene, C3N; tetramethylnaphthalene, C4N --
THE COURT REPORTER: Mr. McClary, you are going very fast. We are not scientists.
W. MCCLARY: I'll continue. I promise -- well, no promises, but I hope that's the last time I have to do that.
Q W. MCCLARY: (as read)
-- leading to the conclusion that the comparison of their concentrations can be used for relative biodegradation assessment.
And then it notes a bit about the subscript representing the carbon changes, and those carbon changes we discussed, that's the pop and chips kind of -- that's what the bacteria will latch on to?
A Yeah.
Q But what I'm picking up from this is that there are a number of PAHs that one could plot and also a number of different ways that one could plot them when trying to establish the gradient that's being discussed.

A Yes.
Q So in the initial submission that we received from CNRL, there was, I believe -- like, one chosen molecule in this IR response, which we'll get into a little bit later. We -- we asked you to -- to graph it a little bit differently and include multiple compounds.
A Yes.
Q Can you speak to CNRL's analysis and why it is that the decision was made to present data in the initial way versus other ways?
A So in the initial way, the compound class that seems to pick up barriers and baffles or seems to establish the most reliable concentration gradients with depth in the -- in the Kirby/Jackfish/Pike areas of the southern Athabasca reservoirs, we found that the phenanthrene group generally seems to plot the most reliably and consistently to -- to identify those gradients. So that's what was presented by and large in the -- in the first submission.
We -- we just didn't want to complicate it; right? Here -- here's the one group that we feel strongly works the best, so that's what we're going to present.
I will -- I will say plotting all three different ways on all six wells showed very, very similar zones or layers of resistance or barrier/baffle, whatever you want to call it. There was no difference in those

depths.
Q So then what I'm understanding is that you did conduct the analysis, and you plotted the other PAHs that --
A Yes.
Q -- you know, Fustic identifies or may be relevant, but for the sake of simplicity, that -- that data was omitted from the initial submission?
A Yeah. We -- we have plots of the naphthalene group, the ethyl dibenzothiophene group, phenanthrene group, styrenes, methyl dibenzothiophenes -- all kinds of different compound classes. The ones that we really trust in -- in this area are the phenanthrenes.
Q Thanks. That -- that -- that helps a lot.
And when you are -- so when you're doing your sample collection at the intervals you identified from the core as we discussed, those samples are sent for GCMS analysis, and there's the whole slew of the different points, and then you conduct the analysis on a number of those points but present the one that you think is most representative. That's the --
A Well, we do -- we do the analysis on -- on every point. So every depth point -- every sample gets the same analysis. We just plot certain compound groups that we feel like -- are the most effective at determining barriers and baffles, and the one that we trust the most generally in the Athabasca area is the

phenanthrene. So that's what we -- that's what we showed.

Q Where does that trust come from?

A What we -- what we looked for initially -- so I started working on -- on GCMS in 2013 in -- in the Pike area, and we plotted everything. We plotted every compound class we could look -- we could think of within the spreadsheets that Schlumberger -- or Gusher at the time would have -- would have submitted for us or -- or analyzed for us. And the four or five different ones that jumped out were the naphthalene group, the methyl and ethyl dibenzothiophenes, the phenanthrenes, and the styrenes. The styrenes generally are those longer chain hydrocarbons that don't biodegrade much, so those ones don't help us nearly as much. The phenanthrenes and the C2DBTs or the ethyl dibenzothiophenes -- sorry if I'm going too fast -- those ones were the more consistent ones in the Jackfish/Pike area, and after doing -- I'd probably say I've looked at 140 different wells in -- in that southern Athabasca area, and it's based on my -- on my experience looking at them.

Q Thanks.

And, again, when you're -- when you're conducting -- you're gathering quite a bit of data; right? There's all -- like, GCMS gives you --

A Yeah. The --

Q -- quite a bit of data --
A -- the spreadsheets got thousands of columns.
Q Yeah. Again, you're looking for -- would it be fair to describe it as a "curve"? Like, is that a fair assessment?
A In our reservoir sands, yes. If we get a -- if we get a very uniform curve with no flat spots or breaks or jump backs or -- sorry -- back steps, that's what we're looking for, yes.
Q And in assessing whether something forms a curve, I'm assuming you're trying to gather as much data as you can; right? Like -- like -- or you're trying to have as many data points that conform with that curve as you can?
A Yeah. Depending on cost too. It's still -- these -- these cost 6 to $800 a sample too, so you can't -- you don't want to do too little, but too many is -- is -- is overkill; right?
Q Yeah. What does it tell you if it doesn't form a curve?
A That tells you your reservoir is very unconnected and you shouldn't put a well pair there or drill a pad there.
Q Thanks.
Now, if we could scroll down a little bit on that same page, we could see the examples. And maybe it's

better if you walk us through these. Are you familiar with the three kinds of descriptions here?
A Yes.
Q Can you maybe walk us through -- this is Figure 4A, B, and C from Fustic 2011.
A So these -- these -- yeah. These are -- these are generalized curves with -- with, you know, eight samples in each, just -- just kind of cartoon showed -- or cartoon shown. And the first -- the -- or -- sorry -- Figure A in Figure 4 is a -- this is what we would look for in our reservoir. If we found this every time, we would say, This is great; put -- put a well pair here. Figure B is a "maybe", depending on the overall thickness of the lower -- the lower kind of connected curve there. And then Figure C is "we never want to do that". I -- we -- I would walk away from that reservoir immediately.
Q And -- sorry -- that's a reservoir analysis; right?
A So both Fustic papers generally only sampled really well-connected sands or very, very clean sands. There -- there isn't much -- there isn't too many samples from a much muddier type of reservoir in -- in both papers.
Q Now, if you were trying to find a reservoir that had a barrier above it, which of the patterns would you be looking for?

A The third one, 'C'.
Q Right.
A Although I would say our subsequent operational knowledge or examining wells that are on producing pads would say if that -- if that upper row of -- or the upper curve of four samples was moved off far to the left in comparison to the lower four samples, we would also consider that not a good result -- sorry -- to the right.
Q Sorry. And when you say "not a good result", scientifically and geologically, what is that?
A In terms of reservoir connectivity. We would say if -- so that -- that column up there, if that moved off to the right quite a ways, we would say that's something we want to avoid as well with our well pairs. If we were looking for a barrier, that would be another good example of one in our -- in my opinion.
Q And do you have any -- I guess, like, a geochemical explanation as to why that -- the shift in Figure 4C of the top four sample points forming that grade and if it's shifted off to the right, why that would indicate a baffle or a barrier?
A So in the Fustic papers, in both of them, they mention those forward shifts or the forward upward increasing shifts are due to low permeability, low porosity, areas where fluid was difficult to mix. In my -- in my

understanding or in my operational experience, that means something that is impacting your reservoir connectivity. That would be where steam would stop as well.
Q And I guess interpreting that back to -- to a geology, what would that be indicative of?
A A barrier.
Q And, again --
A Or, at minimum, a baffle.
Q And the premise for that would be, just so I'm understanding this, that the -- there's a barrier to the mixing present between the two --
A Correct.
Q -- that's resulting?
And that's the geochemical explanation for the --
A So --
Q -- the --
A The smooth slope in 'A' and the slightly less smooth in 'B' means connected. The break or the -- the back step in 'C' means disconnected. A forward step of a similar amount after -- after looking at many, many wells and having some calibration data in terms of observation temperature logs or reservoir saturation tool temperature logs, we see this -- that forward-stepping example be a problem in our reservoirs as well.

Q Problem in your reservoirs. But have you seen it equate to a barrier or baffle as well in practice?
A Yes.
Q And is that evidence on the record anywhere?
A That would be the one -- the example that I showed from the Jackfish -- my -- my technical presentation that was at the CSBG in 2019.
Q Thanks.
So then I guess if I'm conceptualizing this, the evidence effectively is saying any discontinuity between curves that are observed in the data, regardless of the direction, in CNRL's view, based on Fustic 2011 and '13 as well as your presentation, you know, that -- that gives us an indication of a barrier or a baffle? That's --
A That would be my assessment.
Q Thanks.
Now I'd like to turn to the evidence -- or the actual plots that were submitted. It's just a little further down in the same document. It begins -- it's Tab 7C at PDF 244. So this is the -- this was an information request response submitted by CNRL; correct?
A Yes.
Q And this -- you'll see at the bottom of the slide it says "Plotted After Fowler Figure 1"?

A Yes.
Q And I believe if you scroll up one page -- oh, too far. 243. You'll see that this is the Fustic figures?
A Yes.
Q So do these tell us anything different than what was presented initially from CNRL?
A I don't believe so. In the Fustic example, they're plotting the -- or the -- they start always plotting the methylphenanthrene class of compounds and the C2P, which is the dimethyl or ethylphenanthrenes. And what we plotted was the entire group of phenanthrenes in our first submission, and then Dr. -- Dr. Fowler in -- in the -- in the ISH submission plotted the naphthalenes, the dibenzothiophenes, and the phenanthrenes all together in one plot.
Q Now --
A So that -- that was your second --
Q Yeah.
A -- slide there.
Q So would there be any reason to doubt the conclusions if a response is seen in one PAH and not another or to ...
A I would say you might think about questioning things or -- or replotting or maybe going back and doing another few samples, but I -- to my knowledge, we didn't actually see that in these -- the behaviours or

the trends where the same -- plotting the methylphenanthrenes, the dimethyl and ethylphenanthrenes like this example, or the full compounds of phenanthrenes such as CNRL and Dr. Fowler did, as well as the naphthalenes or the dibenzothiophenes.

Now, there -- there -- there may be small changes compound class to compound class, but the overall trends, I believe, look very similar.

Q So, again, it's just a choice as to how you present the data what -- which compound you choose to plot?

A Well, yes and no. In -- in general, the -- I would say the trends would always be the same, but you -- you always want to look for something that moves with depth so that it creates that gradient towards the oil/water contact. So that tells you about the biodegradation. If you plotted the styrenes in these wells, which I have, they're almost vertical. So it just doesn't tell you what -- what your -- it doesn't tell you anything you paid for.

Q And then is it always the case that your biodegradation results in a profile of a decrease in the subject PAH as you go deeper?

A No. Not always. The closer you get to an oil/water contact or a paleo oil/water contact, that always does. If you say -- say you had something that was surrounded

by two aquitards or aquicludes and was completely separated from the upper or lower zone, that one may -- may have a -- a -- a forward shift. But to my -- well, it -- it doesn't happen in these ones. It -- it -- you know, we generally do decrease toward the current oil/water contact, which would've -- would be just below the lowest sample in any of these plots.
Q Thanks.
And I'm just looking at the slide that we have up right now, again, PDF 243, and you can see between about 225 metres of subsea depth --
A Yeah.
Q -- and 220, it appears that there's an increase in the C2P concentration with depth. So what's going on?
A Sorry. Can you make that just a little bigger, the -- the figure on the --
Q Yeah. If we could just go -- zoom in just above the red line on that.
A Yeah. Okay. Yeah. So -- so both classes are -- are doing the same thing there. That would be -- it looks like an 80 to 100 microgram per gram concentration increase right around the level of the mid-B1 mudstone.
Q Yeah. And, I mean, if you draw -- if you were to draw a line from the -- just looking at the blue -- the blue points, if you were to draw a line between the concentrations present at about 226 metres of depth

down to 217 and a half, we'll say, like, the -- the line that intersects with the mid-B1 mudstone or the point that intersects, that would appear to -- to create a curve between 230 -- or between 225 and two -- 217 and a half or so. So, you know, is that the type of data that we're looking for to establish a curve, or do we need something more than that?

A No. I -- I think that's what you would do, although in general, it's more connect the dots than try to draw the curve. Where you see the flat spots or the jumps back and forth, that's where you would say, There must be something in this part of the -- of the strata that is causing compartmentalization. And in general, in this -- in the zone you're looking at, we've got a lot of back steps going up. So as you're looking from the bottom -- from the lower part of that zone up, we -- we're seeing a couple of forward steps and a lot of back steps, which, to me, says a lot of compartmentalization in that general depth interval.

Q When you say "compartmentalization", what does that mean in geochemical terms and -- and also in -- in terms of the geology?

A So -- so I would say in geochemical terms it doesn't really mean anything. It's -- it's more reservoir compartmentalization, or the little bits of sand that we sampled in those muddier sections are their own

little compartments. Each -- each sample looks like it's moving back and back and back further, suggesting this little thing was its own compartment, separated from the ones above and below, and then the next one was, and then the next one was, until you -- until you're almost fully biodegraded in those classes just at the top of the Wabiskaw -- or the Wabiskaw D non-reservoir unit pic there on the -- with the black line at 225 or so.
Q Thanks.
And if you were trying to establish trend based on these data points, would you -- what would your conclusion be about the depths here between about 235 and 217 and a half again? Is -- are -- is there a trend?
A There really isn't. You could make three or four different trends which says that those are -- it's a very compartmentalized interval over that described depth top and base.
Q So now going back -- and if we could zoom out just a little bit, please, and maybe scroll down.
Going back to Fustic, then, does this correspond to anything that we found in Fustic about the signature of a baffle or a barrier?
A This would correspond exactly to that figure -- or -- Figure 4 letter 'C' diagram that -- in the cartoon.

Q So if I recall correctly, Figure 4C showed two separate trends, one trend in the zone above and then a trend in the zone below?
A So you've got that moving back.
Q So is it your evidence, then, that the -- the trend in the zone above here is that there is no gradient, or there is no profile of the degradation with depth?
A There -- there's a backward stepping profile in general, and then we have a little bit of a forward step as you cross above the Wabiskaw C and into the -- into the Wabiskaw B. Yeah. So multiple barriers would -- would create a non-profile like -- like this that suggests a lot of compartmentalization between the samples at those depths.
Q But, again, if we're trying to establish a gradient, as we discussed, you'd probably need more than a single point fluctuating in each direction; right?
A Well, yes. But the -- the strongest gradient there is between the -- in the upper B1, so above the mid-B1 mudstone towards the Wabiskaw D. Those are all back stepping toward the -- toward the lowest concentration in the Wabiskaw D non-reservoir.
Q Okay. So just to confirm, the top four points in this graph, in your view, form the gradient that's being compared here?
A No. About 215 to -- sorry -- yeah. Two -- 217 and a

half to -- to 224 would be a nice -- would be -- would be a gradient that would suggest that compartment was on its own. I wonder if I could get the mouse just to show you --

Q Yeah. By --

A -- and everybody else.

Q Yeah. That would be very helpful, actually. Thank you. And if you need a break at all, let me know.

A No. I'm okay.

So -- so just -- just to clarify, down here we have a very nice gradient where -- where I'm -- where I'm pointing with the little hand. And then up here, this is -- this would be a gradient that -- not really described by Fustic because he didn't -- they didn't sample much -- you know, muddier intervals like this. But each of those stepping backs would say it -- in general, it -- you want to have a gradient go like this if it's a connected reservoir; right? Like this stuff down here. Each of these stepping back suggests that this is a -- its own little compartment, and then there -- there are multiple -- multiple segregated zones within this larger zone.

And then as we go up -- up above, we could say that just at the base of the Wabiskaw D, you start to get -- or -- sorry -- Wabiskaw B, you start to get this again, although there are only two points there. In general, you would say -- in my assessment of this well especially, you would say there's a nice connected reservoir below, and then we start to see these segregations or points that step back toward a -- each of these would've had their own paleo water contact, and -- and that little bit of bitumen would have biograded on its own.

Q Thanks.

And then there's -- there's a point around 227-and-a-half metres that looks like it's the highest concentration on this graph of the blue --

A Right there?

Q -- diamond.

What's the story there?

A So that one could be an isolated compartment as well that did not actually have much water to get rid of. So the -- the bacteria live on water; right? You -- you -- well, they live on the energy they get from the hydrocarbons, as well as they also need nitrogen phosphate -- other nutrients to live. So if there isn't very much water there to begin with or that water was expelled quickly, the biodegradation ceases. So that would have been another little compartment as well.

Q Thanks.

And then just -- just going back, the -- the paper

you reference that you presented -- or the presentation and maybe there was a paper associated, is that --
A No, just the presentation.
Q Is it in our record? Is it in evidence?
A Not the whole thing, just the excerpt that I added --
Q Just the one --
A -- to describe the forward stepping or the --
Q Okay.
A -- steam -- steam being a barrier not always at a back step in the -- in the reservoir gradients.
Q And has anyone else looked at that? Like, have you had any peer review on it, or has anyone --
A Yeah. We -- we actually presented it at that -- at the CSBG technical conference. It -- it is not peer-reviewed. The -- the CSBG presentations are reviewed by the chair of the -- of the -- part of the conference that you present in, but I don't believe they're technically peer-reviewed.
Q Thanks.
Now, going to the -- I guess one more kind of conceptual question before I move into a little bit of a nitty-gritty type of area. How -- how completely can this analysis be applied? Because it seems like the -- the conversation that's happened so far is that if the graphical data tracks with Fustic, then that suggests there is a baffle or a barrier. If the data is

inconsistent, does that demonstrate the absence of a baffle or a barrier as well?
A So CNRL relies on more than just the GCMS. The GCMS is a corroboration piece of data or an additional piece of data. We don't -- we don't core every well, as well as we don't GCMS every single core we -- we take. We would always rely on our geologic principles and correlations from well logs from that core facies as well as 3D seismic interpretations married to those well logs and core data as well. So we're trying to help ourselves be a little bit predictive with the GCMS.
Q So all that to say that the GCMS is sort of a help, not hurt, in terms of identifying the presence of a baffle or a barrier?
A I would agree, yes.
Q Thanks.
And is there any, then, susceptibility to a bit of a confirmation bias, or do you have checks and balances on that?
A Yes. We actually try to calibrate the GCMS with the obs wells that we have in -- in Kirby south, Jackfish. We haven't got any on -- obs wells currently in Kirby north, but we're hoping to.
Q Sorry. When you say --
A Or monitoring wells. So we're -- we're using those to

calibrate our interpretation or our understanding of the GCMS, saying, Did steam stop at this location that was predicted, or did it actually get past it?
Q So that calibration you could also refer to maybe as ground truthing or --
A Correct.
Q And is any of that information before us?
A In the example I provided from Jackfish, yes.
Q Okay.
A That is a ground truth piece of data. We also compare it with 4D -- against our 4D results and RST log results, although the -- the -- the one example that I did present in -- in the technical presentation is -- is not from Kirby north; it is from Jackfish.
Q Thanks. Give me a moment to confer here.
Thanks. Moving into the nitty-gritty.
A All right.
Q I used to do a lot of groundwater sampling, and it's really difficult to do that when it's minus 30 and you've got nitrile gloves on. Led me to think that sometimes sampling methodology can lead to bad results. Is there any concern about methodology between when you spoon the bitumen out of the core -- or when you, I guess, gather the core from the well and when you spoon it out and put it in a bag and send it to Schlumberger that would lead to uncertainty in these results?

A So I -- I don't want to say "never", but it's probably really rare. The reason why GCMS works is that these are non-volatile molecules; they don't evaporate like the very, very light hydrocarbon ends. Like, if you pour gasoline on the ground, you can smell it; right? That -- that's volatilization of that hydrocarbon. These do not. So the reason why they're present in cores and -- and don't require major special handling is because they're tough and -- and they don't gas off really easily.
Q Now, I think -- go ahead.
A Sorry. Schlumberger -- I attended a -- a technical presentation by Schlumberger where they did a -- they did the exact same GCMS analysis from a twinned well that was -- one was cored over 50 years ago, one was cored 6 months ago, and the trends themselves were the same. Some of the absolute concentrations were a little bit lower in the oldest well, but that was their sales pitch to say, Look, you can do this on cores that have been sitting around or cores that you just take fresh, and you're going to get data you can rely on.
Q Now, I believe there's a reference in Fustic 2011 about the vintage of the core. So is that to say that the recent developments have negated the comment about trying to get fresh core for this analysis?
A So I would say the fresher the better always, but I

don't think that going back a few years and -- and utilizing a core that you have stored somewhere sitting on the shelf is -- negates any validity of the data.
Q So then if there are outlying data points that present themselves to you during your analysis, how do you treat those? Is it your inclination to disregard them or to -- to try and associate a geochemical and geological explanation for an outlier?
A So I -- I would say the latter. We would -- we don't disregard them. We would actually talk to the lab and see if there is anything wrong with the machine, if it hadn't been cleaned recently or something like that. They do do repeat analysises [sic] on every well. So they'll pick a single sample or -- or two samples and do a repeat analysis to ensure it's within tolerances. We get those. We don't plot them, but we get them. And if they look like they're very close in absolute concentration for the classes we're plotting, we would go ahead with the data then.
Q Thanks.
And then before the data goes to the lab, is there any susceptibility to the -- to the -- like, the sampling method, like the spooning of the oil out of the core, like, if you get some sand in there accidentally or if you get something else?
A So you -- you're literally spooning the

bitumen-saturated sand. So the sand goes with it.
Q And do those samples have varying concentrations of sand?
A I'm -- I'm sure they do. It all depends on the spot you're sampling. A -- a finer grain sand, you would probably have more grains along with it. A very, very coarse grain sand that has large pores you would probably have a little bit more oil than -- than sand grains.
The method of extracting the oil from the sand grains is cold. It involves no solvent. They press it out, so under very -- under high pressures. So you're ensured a clean representative oil sample.
Also the amount that they actually need to run through the machine is very, very small, and we generally give a more than 50-gram total sample weight, so there's plenty of sample to go around to do a repeat check or to validate if -- if there was a question about a data point.
Q And that all happens at the lab?
A Yes.
Q And I assume they provide a report of their results with respect to quality assurance and quality control?
A Yeah. With every -- with every output there's a QA/QC.
Q And there's parameters within which they operate that they, you know, provide the service within a certain

number of -- like, a -- kind of certain error bars on their results?
A Yes, there is.
Q And so do we have those error bars in evidence?
A I -- I think they were submitted with the --
Q With the confidential --
A -- with the confidential data, yes.
Q Thank you.
If you give me a moment, I need to confer, but I think that might be everything I've got for you.
A Thanks.
Q That's it for me. Thank you very much.
COMMISSIONER CHIASSON: Thank you.
So the Panel needs a short break. Court reporters, how are -- how are you doing? Or I'm assuming perhaps the witness panel could also use -- let's -- let's break for 15 minutes now, and that way that gives everyone a chance to tend to what needs -- needs to and whether that's a walk or otherwise. So we will come back at 3:40.
(ADJOURNMENT)
COMMISSIONER CHIASSON: So thank you, all. Hopefully everyone benefitted from the break as much as the Panel did. We will pass it over now to Ms. Peddlesden to continue with questions.
Q S. PEDDLESDEN: Good afternoon. So I'll be

asking questions about lateral continuity to start with.

S. PEDDLESDEN: Ms. Wheaton, if you could put Exhibit 32.03 at page 5.

Q S. PEDDLESDEN: We've noticed that Canadian Natural has interpreted the mid-B1 mudstone as a marine regional mudstone, and we wanted to look more closely at this particular sample. This is a submission from ISH, but we just wanted to identify which well -- well -- this is 1-3 -- and if Canadian Natural could speak to where the green vertical arrow -- and speak to the variation within the sample on display.

A J. LAVIGNE: The area within the -- between the green arrows is the mid-B1 mudstone. It has some variability. It is a marine flooding surface. It does contain some silt. It is bioturbated by a very small low diversity suite of trace fossils, but there -- there is a bunch of compositional variation within it.

Q All right. And to be more specific -- would you happen to be able to get the mouse where you could point?

A Sure.

Q I'm not sure where it is right now.

A Yeah. We have it.

Q I appreciate that.

A Yeah.

Q Thank you.

All right. So if we start at the top and just work your way down, and if you could speak to the bioturbation and the change in colour --
A Sure.
Q -- and then the bioturbation, please.
A Sure. Would you mind if I started from the bottom and worked up?
Q You can do that. That's fine. Thank you.
A It's a -- it's a geology thing.
So -- sorry. So starting at the bottom, there's a sharp surface, and you'll notice there's a slight difference in the colour here. I would also like to point out that this core is a little bit desiccated from being in storage, and so sometimes after a period of time they don't look quite as good as they do when they're fresh. But within the -- within the mid-B1 mudstone, there are -- for the most part, it's -- it's mud, but if -- if you can follow my cursor up a little bit, I'm sort of halfway now, and you can see some small silt-filled burrows in -- in the mud, and then above it you'll see that there's a darker few centimetre-thick unit that has a bit of a higher organic component. And then as we go into the top of the -- of the unit, there's -- there's also a little bit of bioturbation and a bit of silt mixed in.
And Canadian Natural has been fairly conservative

with what we call the mid-B1 mudstone. Right at the very top of this green arrow where there's an appreciable silt and even some fine-grained sand that has bitumen in it, also bioturbated -- there's some nice paleoficus burrows and things here -- but we've tended to pick the -- the more mudstone-dominated portion when we apply isopach maps of the mid-B1 mudstone, and we would say that where we start picking up appreciable sand or silt and the bioturbation increases in both size and intensity, that's what we would say is now the regional upper B1 sequence.
Q All right. Thank you.
I'd like to turn to Exhibit 43.121, and this comes from Well 1AB-07-02. If you could expand it where the annotations are in red on the mid-B1 mudstone for this well. And if you want to start from the bottom, but --
A Sure.
Q -- just give a geological interpretation of this core sample, please.
A Okay. So I'll start at the very bottom, in the bottom right of the core photo, and perhaps for the Panel's orientation, the -- in these core samples that are turned on their side, the bottom right is the bottom, and then we'll go up vertically through the series of cores so that the top of the cored sequence shown is in the upper left. So we'll work our way through --

through this.

These lower two tubes are the lower B1 regional sequence, and you can see that they -- they contain -- it's -- it's very muddy here, but it does contain sands with some small burrows in them. And then near the top of the lower B1 sequence, not present in every well, but we can see that there is -- we're developing a paleosol at the top. So that's a fossil soil, and it's capped with a coal.

And -- and so what that represents, the lower B1 sequence, is a -- is a tidal flat sequence, and the coaly portion that you observe at the top of that sequence represents a period where the tidal flat had built its way up to sea level, and so you'd have a coastal salt marsh develop along the side.

Now, where the -- yeah. No. Where the red line is, you can see that it's kind of distorted, jumbled up a bit. That's a transgressive surface of erosion at the top of the -- the coal. And so in that case, the coal has armoured the lower B1 sequence. And during transgressive erosion, you can see there are pieces of coal that have been ripped up and churned and incorporated into the lower deposits of the -- of the mid-B1 mudstone. And by the time you get to this point that I'm highlighting, the mid-B1 mudstone is -- looks very similar in character to the previous well, still having bits of coaly material incorporated. And up around this level, we start to pick up some of the bioturbation, the silty small burrows and some very distal storm beds that have put -- put little sand lenses into the marine environment.

And then by the -- where the red line is here, we're into something that more approximates the upper -- the regional upper B1 sequence.

Q And further to that point, does Canadian Natural classify mid-B1 mudstone, as it appears to in this particular sample, as bioturbated and non-bioturbated?

A I would say that the bioturbation in it is quite variable. Many very shaley or muddy rocks are extensively bioturbated, but it's not always visible, and it's -- often when you see the appreciable silt content like I'm showing here just below 470 metres, it's with the incorporation of that silt that you get an indication of how bioturbated the unit might be.

Q All right. So would you consider the mid-B1 mudstone to consist of two distinct facies characterizing it?

A I would say that it's -- it would be very difficult to map those two distinct facies. I would perhaps say instead that the mid-B1 mudstone has -- has variable character.

Q And speaking towards lateral continuity, when you say it has "variable character", what, in your opinion,

would be the best location to sample the character of the mid-B1 mudstone where there's a disagreement between the parties overtop of Drainage Box KN09? Where would you recommend putting a sample, if you were going to take a core sample and drill a well? Sorry.
A Oh, if we were going to take a core sample.
Q If you were going to drill a new well.
A I think when you look at the area of the Wabiskaw -- where the Wabiskaw D has cut deepest along this centre part of that axis, that's the place where it's cut the deepest, and that's the place where you would look to -- to sample or test the presence of the mid-B1 mudstone.
Q I appreciate your opinion on that.
Previously you described the turbated part as potentially the regional upper B1?
A Yes.
Q In your opinion, is this annotation potentially in the wrong spot marking the top, or is it just an interpretive --
A It's -- it's a little bit interpretive, and sometimes the -- sometimes the contact can be kind of gradational, and so some people perhaps would pick it back here at about 470, where you first start seeing coarser grain sand, and the issue with that is, of course, then right above it where my cursor is right

over the O-N-E of mudstone, it's very similar in character to the silty bioturbated deposits below. And so -- so it's -- in this well, it's sort of been picked where the -- the silt and sand component seems to be more dominant.
Q So further to that, if you could comment on the possible genesis and lateral continuity of the non-bioturbated mudstone facies and how that would influence the lateral continuity of such beds. I could put up a different picture for you to speak to. It might be more helpful.
A Perhaps. And while you're doing it, could you please repeat the last part of what you asked.
Q Yeah. Yeah. I will. Okay. So if we could put up Exhibit 43.076.
A Okay.
Q All right. So this is Well 05-02, and if we look at the annotated mid-B1 mudstone in the top right corner --
S. PEDDLESDEN: Ms. Wheaton, if you could zoom in on the top right.
Q S. PEDDLESDEN: -- and just speak to the bioturbation and the lateral continuity.
A Okay. Coming out of the top of the lower B1 in the tube second from the top, there -- right at 469 where my cursor is, there's a sharp erosive surface there

where we start depositing mud, and we can see a bunch of very small, sand-filled burrows in -- in this area at the end of that tube. And then as we come up to the top portion labelled the "mid-B1 mudstone", again it looks like we can see perhaps some coaly ripups, and there's some very small, possibly chondrites-like burrows in the darker shales of the mid-B1 mudstone.

Now, this -- the red line at the top of it is -- is -- this is the base of the upper regional B1 sequence, which is also a shallower tidal flat. And so what you can see right here where my cursor is, you can see some rooting and some overprinting on the -- on the mid-B1 mudstone. And this represents a small inconformity where the lower B1 tidal sequence was flooded over by the mid-B1 mudstone, and then subsequently the upper regional B1 sequence prorated over the top. That's a very shallow setting, and so we've overprinted some roots on the upper part of the mudstone.

Q I'm just going to confer as far as further questions. Thank you.

Okay. I do have one more question. Is it possible that the bioturbated component of what has been defined as the mid-B1 mudstone could be part of the upper B1 regional -- oh, pardon me. I'm getting corrected. I will ask you in a second.

So could it be part of the lower B1 and not part of the mid-B1? And the previous slide would be more indicative of that.
A Right.
S. PEDDLESDEN: If you could put Exhibit 43.121 back up. I appreciate it, Ms. Wheaton. Thanks.
A Sorry. Is this the one --
Q S. PEDDLESDEN: This is the one where you can see the bioturbations quite distinctly --
A Yeah. Okay.
Q -- and the difference.
A Yeah. So I think I understand the question. The bioturbation -- the bioturbate character in the mid-B1 mudstone with the small, silty-looking burrows is different than the bioturbate character in these underlying lower B1 regional sequence mudstones, which have a fair posity [sic] of burrowing. If we could go back, perhaps, to the exhibit that we were just on, if that would be possible.
Q Yes. That was --
A So I just want to differentiate between the relatively non-burrowed character of these particular lower B1 regional muds versus the silty bioturbated ones within the mid-B1 mudstone just to make that a bit of a contrast, and then if we could please go back to the --

Q 43.76? Oh, was it this one that you were referring to?
A No. I'm sorry. The other core photo we were just looking at.
Q That one is actually Exhibit 43.76. 43.076.
Mr. Lavigne, I've been corrected on my question, so --
A Okay.
Q -- thank you for your patience. I'm just going to give you the real question. I just had it upside down.
So the question is: The non-bioturbated facies, could that be part of the lower B1 mudstone? So the opposite of what I said. I was looking at the turbated; I'm looking at the turbated and where you think it fits.
A I'm very sorry. Could you repeat that one more time? I just want to make sure I have it.
Q Okay. This is actually 43.76. Its much more clear in 43.121.
S. PEDDLESDEN: If you could put that one back up, Ms. Wheaton. Yeah, this one.
Q S. PEDDLESDEN: Here I had asked you if the turbated part would be better categorized with the top. That was an error. What I meant to ask you to opine on was if the non-turbated could possibly be classified as the lower B1, not the mid-B1 mudstone.
A Right. In this particular case, I would say no simply

because the -- the mid-B1 mudstone as interpreted here sits above this transgressive surface of erosion and it does display the character that we -- we see in the mid-B1 mudstone. That being said, however, both the lower regional 1 -- B1 sequence and the upper regional B1 sequence are highly variable in terms of their sedimentary character, and it -- it can make it difficult sometimes to actually pick it, and in some cases you end up picking something that's quite thin as the mid-B1 mudstone. That's why we look at offsetting wells, and we try -- we come from stratigraphic datum, and we try to -- try to see at that stratigraphic level what the -- what the differences are.

It's fair to say that it's -- it's recognized as a unit. It is mappable. The sedimentary character is -- is not perhaps completely unique to -- to a deposit, and so part of -- part of our interpretation and the way we map that surface is to compare to offsetting wells so that we make sure we're looking at the same horizon, but it -- it is very fair to say that it's -- it's -- it's variable in its character.

Q   Thank you.

Dr. Boone, my next questions are also on lateral continuity, but they're directed to your expert report, your supplemental report.

S. PEDDLESDEN: So specifically, Ms. Wheaton,

if you can put up Exhibit 50.03 at page 13. And we'll be discussing page 13 and 16 in detail.
A T. BOONE: Okay.
Q S. PEDDLESDEN: Okay. Just starting with page 13, are the vertical permeability values for Facies F1 to F6 provided in Table A1 from the sources listed, which are on this article as Gotawala and Gates and Murtaza and Dehghanpour?
A So those two sources there, they don't provide vertical permeability, right.
Q Okay.
A What they do provide is the steam rise rate in clean sands, essentially, so an analog in this case. And I would have to check which that -- which analog it is. I think it's written there.
And so I assume the 2,000 millidarcies' based on typical for regional -- you know, the -- the good clean sands in the Athabasca.
Q Thank you.
A And consulting with some geoscientists, they said it might be a little bit higher.
Q And for the F5 facies, how did you come to the Number 1 microdarcies?
A For the F5 facies, I really assigned it a 1 millidarcy, although I thought that was very conservative. If I go into the literature, there's a lot of evidence of

measurements of less than 1 millidarcy and even
hundredths of a millidarcy in, you know, hundred
percent shales or muds.
Q Particularly which muds were you basing the -- the
values on?
A I wasn't basing it on -- particularly on any specific
mud.
Q Okay.
A I mean, it's -- it's sort of general.
Q Okay.
A And -- and now the interim permeabilities there,
there's another chart there. Did you want to go to
that, the one on the next page based on some
micromodelling?
Q Yeah. That would be great, yeah.
A So let's talk about that. So, you know, the -- if
you're going to do reservoir modelling of facies like
this -- and this is the challenge for doing any
reservoir modelling of steam moving up through the
confinement, is how do you capture all these fine bits,
okay, that are -- that you can look at them, and you
can see there's tens to many tens in -- in a metre.
And so the standard way to do that is to do
micromodelling. And so that is -- you create a
simulation model on something that's, like, a metre
cubed. And I -- I -- I think in that subtitle on that

figure, it describes that, the -- the size of the models.

Q Right. And how did you get your values for this diagram?

A So that's not my work. That's taken from a paper by the Clayton Deutsche group out of the University of Alberta that are sort of the experts in that area, and it seemed to be pertinent, so I included it here. And you can see that -- that, you know, in this section here, they -- they modelled things like muddy his, and they typically got very low vertical permeabilities; right?

And so when I compare that to my table, I'd say the table -- I have higher numbers of vertical permeabilities, and that -- that was intentional that it -- that it be conservative.

Q Could you confirm that the Wabiskaw D upper heterolithic unit and the Wabiskaw C are both given the F5 facies as their values for your model?

A I -- I would say that's generally true, but you can look -- you know, I only applied it to the four cases that are included --

Q Right.

A -- in my report, and it -- and it's visual mud index. So it wasn't done specifically on a -- on a facies basis.

Q Okay. Yeah. That was the next question, is what was it based on, the visual mud?
A But that -- that's the standard that's sort of used in -- in industry that's, you know, been found to be reasonably predictive of where you get good SAGD pay. But I'm -- I'm taking those same facies and reversing it and saying, Let's -- let's try and use this to model the -- the confinement strata.
Q Okay.
S. PEDDLESDEN: Ms. Wheaton, can you take us to page 16.
Q S. PEDDLESDEN: And, Dr. Boone, can you talk about intervals of similar lithology? Can there be intervals of similar lithology deposited in a range of depositional settings?
A T. BOONE: I -- I -- I would say yes, but you're -- you're getting outside my area of expertise. I would consult with my geologist friends on that.
Q And then could you speak to the distribution of the same or similar lithology in, for example, a deltaic meandering channel or an estuary setting and how that may be of different lateral extent or continuity?
A Again, you're -- you're out of my expertise.
Q Oh, absolutely. Yeah. Canadian Natural, you can answer.
Mr. Lavigne.

A J. LAVIGNE: Could I please bring up a
figure?
Q Oh, yes. Yes.
A Exhibit 43.002, PDF page 26. Thank you. If we could maybe just reduce that a little bit so we could see the whole slide, please. Thank you.
So visual mud index is sort of a 1D point that you would use in core. And to your question, yes, different depositional settings can have the same visual mud index. And so one of the differences -- the McMurray formation point bar shown in the bottom half of the slide show continuous mudstone beds over -- that can be mapped for tens, even over a hundred metres in -- in well-studied outcrops.
The -- the -- the deposits of the Wabiskaw D non-reservoir unit and the basal upper Wabiskaw D unit are more like the top two panels where there are -- there are flasers and wavy beds of mud with -- with interbedded sands.
And in -- when we look at the diagram in the top centre, what happens is we have a dominance of mudstone versus sandstones, and the -- sorry. I'm just looking for a figure. And in that case, individual mudstones for -- may not have the same lateral extents that we would think of in point bars. And that's typically why we think about and look at the Wabiskaw D quite

differently than the McMurray.

If I could -- if I could please ask to go forward to Slide 30 of the same presentation, please. This is a modern example from an estuary in Europe. And just to orient the Panel, in -- in the lower right you can see some sort of sand dunes that -- thank you. You can see some dunes across the bottom of this estuary. And what -- what has happened with side-scan sonar, the bottom of this channel was imaged, and right where my cursor is dragging in the centre of these red circles, you can see -- you can see a slight discontinuity, and that's a fluid mud caused from the way mudstones deposit in estuaries. That's very different than the way mudstones deposit in rivers. And so in this particular case, the -- the mudstones that -- that are being seen here are on the order of 1 metre thick.

Now, that being said, they're very high -- they have a high volume of water in them. And so in the rock record, when they compact, they'll be much thinner than that. But what this shows is how mudstones can be deposited in -- in -- interbedded with sandstones, and that describes the nature of that flaser-type bedding that we see.

Now, if I could please ask to go to the next slide in this same document. Thank you.

This is another scanning profile, and you can see the scale of this, and what's -- these deposits -- these laminated deposits that I'm tracing out here with fairly horizontal beds, that's a deposit of fluid muds that's draped all of the sand dunes along the bottom of the estuary. And in this case, if you notice the scale in the lower left here is 100 metres. So what this has deposited is a deposit of mudstone beds that is on the order of a metre thick over perhaps 900 metres to a kilometre as a fairly continuous deposit.

So while the mudstone distribution of individual mudstone beds within the Wabiskaw D -- individually they are smaller, but as an aggregate of deposits in high visual mud index deposits, they can be mapped over fairly large areas.

Q Thank you.

Back to Dr. Boone. With your calculations, you were relying on homogeneous confinement strata, I believe? Can you speak to that?

A T. BOONE: Homogeneous at what -- sorry. Homogeneous at what scale? So, you know, clearly they're heterolithic at the visual mud index scale. And so, you know, it's being classified into units, but there's no assumption of it being homogeneous. The --

Q Okay.

A -- the condition is that it's a heterolithic unit and that --

Q Okay.
A -- that if steam was going to rise through it, you know, especially where there's a lot of mud, it's a -- it's a very torturous path.
Q Right.
A And -- and the other key point there is it's not just steam rising up; it's -- bitumen has to drain down that same pathway. And if it becomes a torturous pathway, that's a slow process, which is why steam rise becomes very slow.
Q Okay. And when you submitted your calculations, could their validity be reduced based upon a lack of lateral continuity?
A You know, definitely. If -- if, for example, there was a channel that was sand filled that cut through those facies and was, you know, between the wells or -- or you drilled it, then that would be potentially an issue.
Like -- now, there's -- there's a lot of low-quality facies in -- in all the wells over these drainage boxes, so it -- it -- that seems unlikely. It seems that the channels that are there are mud-filled and -- and impermeable, but the geo -- my geoscience friends there might want to elaborate on that more.
Q That's okay.
Are you aware -- in your opinion, could the

bioturbation increase or decrease the vertical permeability for the steam to rise?
A In -- I'm not aware of any case where bioturbation of a shale has made it permeable to steam, okay, in that -- for that to happen, would the -- the bioturbation would have to be filled with sand, and it would have to be connected through the whole section. Now, that possibly can happen, and maybe there's examples out there. But the thicker the section you get, the more unlikely it is that bioturbation will -- will provide pathways for steam.
Q And did the model consider variable bioturbation?
A No. It's -- it's a visual mud index --
Q Right.
A -- just as you see there.
Q And as far as how the visual mud index for the Facies 1 to 6 scheme is calculated, you spoke to using typical numbers that you would see in literature and picking the 1 microdarcy as a conservative one. Is that --
A For the --
Q -- the correct --
A -- permeabilities associated --
Q -- permeability?
A -- with them. The -- the visual mud index, that -- that chart of those facies is from Suncor MacKay, and -- and a lot of other people have reproduced it.

Q Right. So do you know if it was created with digital
software, or is it variable between geologists
performing the work?
A My -- I mean, in my experience, it's geologists looking
at it and -- and visually making a determination.
Q Thank you.
Okay. So we'll be moving to the next topic, which
is monitoring.
S. PEDDLESDEN: Ms. Wheaton, if you could put
up Exhibit 15.01, PDF page 106 of 505, and this is the
Wabiskaw net gas isopach.
Q S. PEDDLESDEN: So similar question that we
had put to Mr. Lavigne, when you look at this map and
you look at particularly the KN09 drainage area, where
would Canadian Natural recommend putting a monitoring
well and provide supporting reasons?
A G. IANNATTONE: Okay. I'm going to try and
answer this one.
We have plans to drill a strat well that's
slightly to the northeast of the KN09 box. And so in
those plans to drill that strat well, we would case it
and make it available as a Wabiskaw B gas monitoring
well.
Q And have you considered putting the sampling well in an
area that has thicker gas pay?
A I don't know exactly -- the exact location, but I would

guess -- or maybe Mr. Sverdahl knows it, but it would be in that -- not the darkest red, but it would be likely in that -- the next reddest colour. And I'm not sure what that contour is, but it might be 2 metres.
A S. SVERDAHL: Yeah. It would be in that range. We have tried to optimize it as -- as much as we can to make sure we're going through what we're interpreting Wabiskaw B gas.
Q And then how will the gas sampling be submitted? In your latest reply submission, you had mentioned providing a gas sampling of the Kirby Upper Mannville II gas pool prior to production. How about a frequency after that? What would you think would be reasonable to notice any anomalies in the Kirby area -- Kirby north Wabiskaw B?
A G. IANNATTONE: Okay. Just to clarify, so we're talking about gas sampling, and you're talking about gas sampling after the GOB gas resource is allowed to produce?
Q Right.
A Okay.
Q Yes.
A So I believe, as typical in gas operations, that as the gas is produced there is a frequency of normal gas sampling. I'm not a hundred percent sure what that is, if it's monthly or annually. It probably depends a lot

on the type of gas, but -- so what I'm trying to say is there's a natural process that gas samples would be taken and analyzed on a frequent basis.
Q I might be confused. Are you talking about the gas sample from the Wabiskaw B, the monitoring gas sample?
A No. No. I'm talk -- so -- okay.
Q Right.
A So just to be clear --
Q Yeah. I think we're talking about two different --
A Just to be clear, when we talk about gas sampling, we're not necessarily talking about the gas monitoring wells.
Q Right.
A It could come from other wells. And so --
Q Right. Okay. I --
A -- after --
Q I wanted you to speak to sampling of the monitoring well. In the reply submission, there was acknowledgement of getting a baseline gas sample --
A Right.
Q -- by Canadian Natural --
A So -- so I guess I would say we haven't necessarily decided -- okay. You're talking about the baseline -- baseline sample now?
Q Yes.
A Baseline not -- okay.

Q Baseline sample --
A Let's go to the baseline.
Q -- of the Wabiskaw B --
A Yeah.
Q -- gas reserve.
A Right. Right. So first --
Q Yeah.
A -- of all, there's four wells that are available, I guess, in the Kirby Upper Mannville II gas pool, and all of them are GOBed. So, first of all, we'd have to apply for a GOB waiver to get permission to -- to sample. Then we would select, I believe, one of the four wells, probably the most convenient one where either, you know, it could be an access issue or it could be a mechanical issue downhole, but we would like to select the most convenient one. And we would have to produce the well for some period of time just to clear the wellbore from the gas that's been sitting there for decades, and we would sample one of those four wells. And that would provide the baseline.
Q And if you were required to submit gas sampling on an interval basis, would you be able to submit it to the AER in an Annual Directive 54 report?
A Yes, we could do that, but -- one moment, please.
Okay. Excuse me. Yeah. So our plan would be to collect the baseline sampling now, once, right, and

collect it again prior to the GOB gas production coming back on. So that could be years later to see if there's been any contamination over the period. We were not committing to an interval of baseline gas sampling over the years.
Q All right. Moving on to maximum operating pressures.
S. PEDDLESDEN: So for this question, if we could have Exhibit 15.01, Ms. Wheaton, at PDF page 32, paragraph 135.
Q S. PEDDLESDEN: All right. So we have here start-up, mitigation, 5,500 kPa rather than the MOP of 6,000, adopting the recommendation, and we've spoken about this already. Long-term MOP of 6,000 kPa and then the 6,600 for the 24-hour start-up. So my question is: Provide the technical basis for the proposed long-term MOP, maximum operating pressure, of 5,500 kPa at KN08 and KN09.
A P. THOMSEN: Could you clarify? Are you referring to the modified long-term maximum operating pressure of 5,500 in the reply submission?
Q Yes.
A Okay.
Q Just why it was changed to 5,500. Just confirming the technical reasons. The application was 6,000, so --
A There -- there isn't a really solid technical justification for reducing it. I mean, the evaluation

supported the use of a long-term MOP of 6,000 kPa.
Q All right. So do you foresee any potential technical concerns with this change in your application?
A Just a moment, please.
Okay. So with the modification to the long-term MOP, there -- there is some minor risk reduction associated with that, and associated with that is there -- there could be some increased operational downtime associated with a reduced long-term MOP for upset conditions. We'd mentioned --
Q Power outages?
A Interruptions.
Q Steam?
A Potential -- potential for scale plugging inside a well. So ...
Q Scale what? Pardon?
A Scale plugging inside a wall.
Q Okay. Thank you.
All right. Moving on to the geomechanical model, if we could get Exhibit 46.002, PDF page 43 displayed.
All right. So here we have the model, but as pointed out earlier this morning or afternoon -- it's been quite a day -- we didn't really understand Canadian Natural's assumptions or input parameters for the analysis, so we're just going to explore that a little bit. Describe the geomechanical lab testing

conditions.
A D. WALTERS: So the -- so there was a figure in the report that showed some lab testing for mudstones. So those were triaxial tests conducted in a lab, so standard triaxial tests at different effective confined stresses, and that gave some information about the elastic properties and the shear strength.
For the sand itself for the McMurray, analog data was used based on UTF public data, so -- and that's been used in other projects in the past as well. And there's a paper reference, I believe, at the bottom of the page.
Q Which formation were the samples taken from for the model, or were they assumed to be McMurray sand or ...
A The samples were actually taken from the Clearwater and the Wabiskaw shales, so the -- the main caprock for the mudstone testing.
Q Okay.
A Yeah. And the McMurray data was taken from McMurray sand.
Q Okay. I'll just confer with Baohong.
Okay. Canadian Natural, did the tested samples have the same elastic properties and strength as the confinement strata found -- or contoured and estimated to be found in the KN08 and KN09 drainage area?
A Yeah, so no samples from the confinement strata were

actually tested in the lab. So we did do some log comparisons to check the gamma ray, which is a measure of the V shale that's been talked about earlier today, and it was comparable to the mudstones that were tested but not exact, and so not exactly the same mudstone.

But those -- those -- because that data was available and -- and relevant because it was close -- regionally close to this area, that was used to guide. And then, as was described in the report, a conservative assumption for the shear strength, then, of that -- those mudstone layers was assumed to add a layer of conservatism.

Q All right. Describe the stress range used to determine the Young's modulus.

A So the -- the Young's modulus values in the table that were used, so the 500 MPa is -- that number was based more on experience and would be representative of mudstones over an effective stress -- stress range of 500 kPa to 2, 2-and-a-half -- 2,500 kPa. And then the -- there was, as mentioned, a sensitivity done with a stiffer value assigned to the mudstones to do some sensitivity, and the range of those effective stresses was from 2,500 up to 9,500 kPa. So it covered quite a large range.

Q And what are the range of effective stresses observed in your model results?

A So the -- the initial effective stress is approximately 4,500 kPa. And so in areas where the operating pressure was increasing, that could potentially go down to 2,500 kPa, and it potentially could increase as well with the heating and the stress changes associated with heating.
Q And is that the pore pressure? That's the effective stress in the pores, or is that separate?
A The effective stress is the total stress minus the pore pressure. So --
Q Oh, thank you.
A Yeah. So as the pore pressure increases with your operating pressure, then the effective stress would decrease.
Q Thank you.
A Yeah.
Q I appreciate that.
And then which model are your results based upon?
A How do you mean, which -- "which model"?
Q We noticed in your submission it had 500 MPa to 1.3 gigapascal, and then just as you were speaking you mentioned a range in the effective stresses, 4,500 to 9,500. So I'll just confer on how to --
A I think that cleared -- that clears it up. So the -- the model that was presented in terms of the results was based on that tabular data, so it was the 500 MPa

stiffness for the mudstone layers and then an
elastoplastic model for the sand.
Q And it was based on the confinement unit that you had mentioned earlier?
A The confinement stresses, correct.
Q Oh, sorry. I meant the confinement strata.
Okay. So the effective stress is based on which confinement unit, as in the mid-B1, the lower B1? That's the confinement unit we're hoping you can identify.
A Yeah. So the -- the main focus of the shear stress level was the mid-B1 mudstone in -- in the long-term SAGD model. So -- so that was sort of the -- the layer that was focused on in terms of plotting across the model and through time -- and monitoring through time.
Q The mid-B1?
A The mid-B1 mudstone.
Q Okay.
A Yeah. And -- but the entire B1 sequence was included in the long-term model.
And then in the -- in the fracture models, there was a slightly different treatment where the entire B1 sequence was assigned properties associated with the stress gradients.
Q And by the entire strata, you mean all the identified

strata from CNRL -- -- pardon me -- Canadian Natural, the six that worked together? Okay.
A Yeah.
Q And then, finally, provide the thermal expansion coefficient used for the McMurray post-B reservoir and confinement strata?
A Yeah. So the -- the linear thermal expansion coefficient that was used was 1 E to the minus 5, 100 degrees Celsius. And that's a value that, again, we have a lot of experience using and matching surface eve [phonetic] data from other projects. We did run some sensitivities with higher thermal expansion coefficient as well, but the 1 E to the minus 5 is our best estimate of our representative thermal expansion coefficient.
Q Yeah. And then you found those coefficients would be representative of the McMurray sands and confinement strata that you would find in the KN08 and KN09?
A Yes.
Q Thanks.
Okay. So there's a bit more on geomechanical. This is Exhibit 46.002, same exhibit, but at page 71 and 72.
S. PEDDLESDEN: If you could scroll down, there's a helpful table coming up. Oh, probably the next page. 71, 72. That's the table. Thank you,

Ms. Wheaton.
Q S. PEDDLESDEN: All right. Based on the current models, provide the calculated maximum SSL and TSL, so the shear and the tensile, for other mudstones and non-reservoir and heterolithic strata that Canadian Natural will rely upon as confinement strata in the absence of A2 mudstone and mid-B1 mudstone.
A So -- yeah. So this table is representative of the mid-B1 mudstone, and so you can see the number is tabulated there. I guess to get you the exact numbers, I'd probably have to take it away and come back.
Q That's okay. We were more so just exploring if you had conducted a sensitivity analysis and if you had assumed that the mid-B1 mudstone was present with lateral continuity.
A So the -- several conservative assumptions were made in the modelling again to try and investigate some of the risk of containment. So the -- in general I would say these numbers are representative of the lower B1 and the entire B1 sequence in that it's a mud-dominated sequence, as has been talked about previously.
However, in -- in the long-term model, the initial stresses that were assigned to the lower B1 and the upper B1 were lower values to be conservative, and therefore the shear stress level and the tensile stress level were higher than these values. But the -- some

of work that we did, specifically the log analysis, shows quite nicely that the mud content that's been identified by geology shows up in the log in terms of gamma ray and also shows up when you calculate elastic properties from the log for the entire B1 sequence. So it gives us some justification for applying these values to the entire B1 sequence from a confinement strata integrity point of view.

So I guess the short answer is we'd say these were -- these are applicable to the entire B1 sequence. And then, as was asked, that's for the base case or that table of values that were -- were documented. Several sensitivities were investigated with, you know, higher thermal expansion and some variations -- other variations that may cause more uplift or may cause more stress change in the caprock, like the higher stiffness, and all those values, the shear stress level and the tensile stress level were well below 1. So although we investigated some very conservative low cases, there was no case that looked to -- to be problematic.

Q Thank you.

If you could now discuss potential impacts that natural fractures and faults, if they exist, may have on the rock strength.

A So the mudstone, as we discussed, was assigned a shear strength lower than the mudstone data that was presented. So it was assigned a cohesion of zero and a friction angle of 30 degrees, and that was done to -- even though the characterization shows, you know, very small amount of fractures or no fractures in those units, to make a conservative assumption that there could be fractures in those units, and so that frictional strength assigned then accounts for the potential of having fractures present.

And -- however, for faults, potentially faults because if -- especially if they were seismic -- seen on seismic, then there's some significant deformation on them. Faults would typically have even a lower shear strength, but we've identified no faults on seismic, so that suggests if there were any faults, their subseismic scale, very small offsets, and therefore the shear strength, we wouldn't expect to see a significant difference lower than this conservative assumption already made.

So from that perspective, we feel this is a reasonable assessment, and although there is some uncertainty in it because the evaluation shows the risk is so low of any problem with confinement strata integrity, we feel it covers and is adequate to describe the situation.

Q Even in the potential absence of the A2 mudstone, which

we all agree is absent. How about in the potential absence of the mid-B1 mudstone? Is it still a conservative, in your opinion, model?
A Yeah. I think from the log data that we have, it shows consistent high mud content behaviour of the B1. So although it's not a -- necessarily a marine shale with -- with lateral continuity over large distances, the high mud content then would give it geomechanical properties and strength closer to the muddy behaviour that we've assigned it.
Q Okay. And correct me if I'm wrong, Canadian Natural -- I seem to remember the seismic data was accurate to within 7 to 8 metres. Is that --
A S. SVERDAHL: Yes. That's our estimate --
Q Okay.
A -- of the resolution of the seismic data.
Q I don't have a pinpoint, so thank you.
All right. You're off the hook on geomechanical. Thank you for providing that background.
We'll now look at thermal compatibility, which is Issue 5. Oh, I apologize. I should have conferred before I let you go, Mr. Walters.
All right. Back to the geomechanical model. Discuss how potential variations in the minimum in situ stress of the confining strata may affect the predicted SSL and TSL.

A So the -- both -- both of those parameters are affected by your assumption on the initial stress date. So there were some sensitivities that we ran as was documented for the fracturing risk but for the long term as well, and so if you assumed a smaller or a lower-stress gradient than what we assumed based on our DFIT testing, then it would increase the initial shear stress level and/or tensile stress level.

So, for instance, in that table that's in front of you, you know, potential -- instead of 0.36, it might increase to 0.46 to start, and that's if you would maybe decrease the stress gradients by 1 kPa per metre. So that sensitivity is run, but then the incremental changes through the life of the operations would be the same. So they would all shift, then, by those values, and -- and they would all shift by the same amount because nowhere through the history of the model did we encounter any shear failure. So there was no, then, complex stress or strain behaviour that would then cause something other than a linear shift to those values.

Q And then provide the minimum in situ stress and the predicted SSL and TSL based upon that.

A So for that sensitivity -- so we looked both going lower and going higher, but on the low end, so instead of the 13.1 kPa per metre, let's say, for the McMurray

sand --
Q Right.
A -- and then the 14.6 kPa per metre that we would have for the mudstones, they -- I initialized it with 12.1 kPa per metre and 13.6. So similar stress contrast but dropped the numbers by that 1 kPa per metre, and the pressures remain the same.
Q Thank you. I'm just going to confer if you're done.
All right. We're going to move on to thermal compatibility. You're clear, Mr. Walters. Thanks for that.
Thermal compatibility was Issue 5 that we're addressing at this hearing. I would like to see Exhibit 50.002, PDF page 56. And we're looking at paragraph 211 to 212, so it will be pages 56 and 57. Perfect. All right. So we start with 10-34 well. In the revised workover plan submitted in Canadian Natural's reply, there was a plan to knock the permanent bridge plug to the seller and equip the well with continuous downhole surface readout pressure and temperature monitoring.
Is Canadian Natural planning to place thermal cement inside 114.3-millimetre production casing across the non-completed McMurray formation in Well 10-34 as it is required in Section 5.4.2 to 125 of Directive 20?
A L. ROCHE: As of right now, the plan was

not to put -- was only put cement across the McMurray formation as it is a monitoring well. So right now we weren't planning to cement the 114 ml.
Q So 10-34 is going to be used as a monitoring well?
A Yeah. We've committed to making that Wabiskaw B gas monitoring well.
Q How deep does 10-34 go?
A It's got a total depth of 500 metres.
Q So it goes right down into the McMurray formation?
A It encounters the McMurray, yes.
Q So where are you putting the monitoring on 10-34?
A We have existing perforations in the Wabiskaw A from 435 to 438.5, and we would be aiming to set it 1 metre above that.
Q And then what's the plan from 438 to 500?
A It would be remaining open.
Q Why would you choose not to abandon the bottom leg with thermal cement? What's the future plan?
A The future plan here, eventually post-GOB, would be to return it to production, but as far as cementing it, that's an option.
Q All right.
A Okay.
Q Are you aware of the current casing in Well 10-34?
A Yes. It's J55.
Q And how about the connections?

A They're, like, the standard API 8 rounds, so it would be non-thermally compatible as per our protocol.
Q Right. And they're not compatible to Directive 20 for a thermal area?
A So as my colleagues just mentioned to me one option that we would leave -- use to keep the well open -- sorry -- is to have the ability to do temperature logs, R, C, P, and X logs for monitoring SAGD chamber growth.
Q So you're proposing potential monitoring deeper in the 10-34, deeper than the 4-38 plus 1 metre?
A Those are done on an annual or a biannual basis.
Q And how do you propose to deal with the non-thermal capability? Are you going to be monitoring the steam chamber growth and whether or not it gets close to Well 10-34?
A We'll have the surface readouts in there. We'll have the pressure data at Wabiskaw, and we'll also have the temperature, and as I just mentioned, we will be using it for PNX logging, which is an annual or biannual basis, but it gives us temperature in the wellbore.
Q And you predicted my next question. Thank you. Okay.
All right. One more question on thermal compatibility. I'd now like to have Exhibit 50.002 -- is that the one we're on? Yeah. So it's just the same area, basically. Paragraphs 211 to 218. Here we have

Canadian Natural is planning to remediate the thermal non-compatibility issues related to Wells 12-34, 10-34, 10-2, and 10-3. The concern would be the thermal compatibility.

And the question is: Does Canadian Natural plan to conduct cement bond logs verifying if there is adequate isolation behind intermediate casing above the McMurray formation to ensure isolation to surface casing? So from the intermediate casing above the McMurray formation to the surface casing in the existing cased wells located within the drainage area of Pads KN08 and KN09.

A That is not in our plans right now. On the one well that we are looking to abandon, as per Directive 20, we will be using cement retainers on those wells. As far as the other ones --

Q How does that address behind the casing, like, on the ...

A It doesn't. Can you repeat that.

Q Oh. Just if you're planning on abandoning it with thermal cement, is that going to come back to surface? Like, are you going to know all the way around or should -- like, would a cement bond log confirm whether or not there were any integrity issues of communication between zones?

A A cement bond log would definitely confirm if we have a

strong cement bond, but we do not have any cement bond logs on these wells specifically.
Q So then how would you represent to the Regulator that you do have well integrity and that we don't have to be concerned with communication?
A So all four of the subject wells that were identified in our thermal compatibility study do have thermal cement initially placed in it, so that is, I guess, the driver, plus we'll have monitoring throughout KN08 and KN09.
Q And the monitoring would have a drop in pressure that would let you know there might be communication between zones, or what would the monitoring reveal?
A The monitoring would reveal if we were to have a communication into the Wabiskaw B.
Q And then how timely would it be to report it to the Regulator if you did see an anomaly?
A Similar to the bottom water in our scheme approval, I would probably look at 30 days with a plan to remediate in 60 days.
Q Okay. Yeah. No further questions. Thank you for your time, and thanks for answering those. The Panel will have their own concerns and questions, so thank you.

The Alberta Energy Regulator Panel Questions the Canadian Natural Resources Limited Witness Panel

COMMISSIONER CHIASSON: Thank you, Ms. Peddlesden.

The Panel does have some questions for the witness panel. So we'll start off with Commissioner Zaitlin.
Q COMMISSIONER ZAITLIN: Thank you very much. I just have two sets of questions to ask. One will be for a tag team with Mr. Lavigne and Dr. Boone, if possible.
Mr. Lavigne, you showed a number of examples of the various isopach maps by stratigraphic unit that basically shows the distribution of the different stratigraphic units across KN08 and KN09. You showed various cores showing the range of facies. Basically what this together shows is highlighting the heterogeneity of the containment strata in those drainage boxes, specifically in terms of thickness across the area. Dr. Boone put forward in his -- in his data showed data associated with the steam rate rise methodology.
So the question I have first is: Is that data put together in any way in terms of a reservoir model that shows the 3D distribution of the different reservoir facies and units across the area showing the -- that heterogeneity?
A J. LAVIGNE: Sorry, Commissioner Zaitlin. Canadian Natural has conducted a preliminary geomodel that was not ready in time for these proceedings. It is standard practice that we make 3D models over our McMurray assets, so ...

Q So where you are now, does it show significant heterogeneity across those boxes?
A Yeah, the models --
A S. BARLAND: Hi, Commissioner Zaitlin. So I was involved with some of the model building or preliminary stages of model building and the low permeabilities in the heterogenous confinement strata units are quite well represented in the current version of the 3D model, although it is in a preliminary state. I would say it represents or closely corresponds to the higher numbered F4/F5 facies that Dr. Boone had described and -- and shown you guys earlier today.
Q So to follow up on that, are there certain areas in the KN08 and KN09 boxes that would preferentially be at -- be at risk for earlier breakthrough because of specific facies distribution in -- in those boxes?
A Yeah. So we're just in the very early stages of -- of trying a few cases of simulation on that model. No indications as of yet for steam breakthrough. Again, scenario building and running the actual predictive history match or the forecast history match is in its early stages.
Q Just to follow up on that, though, do you think this model, when it's built, would be able to help highlight where the best position of the monitoring wells should be?

A Any -- any model has uncertainty, so using it to predict a single 7-inch position for a monitoring well may be more than a -- than a model can -- can guarantee to do. It may help inform that decision, but I would say it's probably too much to say, Yes, it's going to depict the right spot.
Q Following on, on a second --
A Sorry, Commissioner Zaitlin. I'm just wondering, is it the gas monitoring well you're -- you're asking about?
Q I'm asking more about how the distribution of containment facies will be effective across the area spatially to make sure that there's no upward movement of steam that may or may not happen and may or may not go into the Kirby pool.
A Okay. So not a specific well, but identifying areas of potential better spots to place one --
Q That's right.
A -- if needed?
Q Northeast corner, northwest corner, that type of thing.
A Excuse me one more second.
Q Sure.
A I think -- I think we'll leave it there if you're -- if that does answer your question. I would say the variability is -- is hard to predict, although once we get to that stage, it could be informative.
Q Fair enough.

For Mr. Lavigne, you talked about the 1-3-75-9-W4
well and the identification of that well having a tidal
creek that cut out the B1 mudstone. What was the
dimensions that you used -- that you thought occurred
with those tidal creeks and how many other wells, if
any, actually intersected similar facies at the B1
level?
A   J. LAVIGNE: I'm just going to pull up an
exhibit quickly, if I may.
Q   Yes. Of course.
A   Could I please pull up Exhibit 050.003, page 52.
Thank you. Sorry, Commissioner Zaitlin. Your
question was the -- the scale of this feature and have
we seen it elsewhere?
Q   That is correct, yes.
A   Okay. This is the -- while both the regional lower B1
sequence and the regional upper B1 sequence are quite
variable in lithologies and -- and do contain some
sandier deposits that would be interpreted as tidal
channels, this is the example that we -- this is the
only example we've seen directly on the pad regionally,
away from these pads we have seen small features like
this. In fact, in the KN06 area, there is a small
feature like this as well that seems to be confined to
the parasequence that doesn't have a significant
downcutting.

As far as scale, in the three-well cross-section in the centre -- top centre of this figure, these wells are about 215 metres apart, and so it -- it's very -- it's very well constrained aerially. We can't correlate it to any of the offsetting wells.

I'd like to invite my colleague Mr. Sverdahl to speak on seismic.

A S. SVERDAHL: Yeah. Just to add we have looked substantially at the seismic at this well doing time splices or special decomposition slices, coherency as well. Unfortunately the feature is too thin and/or does not have enough reflectivity to pick up very well as a geomorphological feature that we can map or see at this well. So, unfortunately, we're not able to determine the -- the size, the aerial extent of this -- this feature at this well.

Q Would there be any -- is there the potential for having any other channel-form-like bodies like this cutting through potential containment strata in any other of the Wabiskaw units?

A J. LAVIGNE: Based on our understanding, and our -- sorry. I'm just trying to pull up one more figure.

Q No problem.

A My apologies.

Could we please pull up Exhibit 043.002, page 29.

Thank you.

Commissioner Zaitlin, you asked specifically about the Wabiskaw. So for context, in the lower left of this figure, there's a map, and the Wabiskaw sandstone trend is shown in orange in that southwest/northeast orientation, and so this model slice was -- was submitted to try to explain the mudstone-rich facies associated with the Wabiskaw. And as mentioned earlier, the incision at the base of the Wabiskaw D thins to the south and rises, and so this figure was included to try to contextualize the two Wabiskaw D confinement strata over the KN08 and 9 pads to the south.

Based on our understanding from having examined cores and seismic of this Wabiskaw D sandstone body, we -- we don't -- we feel like this tidal bar has been vertically accreting and is draped with these mudstone facies on the side. In contrast to Strobl and Shields earlier core work, the occurrence of high-angle cross-bedded facies is volumetrically very, very small and the breccia component as well in the sands is very, very small based on probably about 50 more strat wells since that earlier work was compiled, and so we don't see much evidence of channelization in those non -- in those mudstone-rich non-reservoir facies and haven't observed any channelization in any of the cores or

wells that we've drilled.
Q Okay, thank you. I'll pass it over to Commissioner Chiasson.
COMMISSIONER CHIASSON: Thank you, Commissioner Zaitlin.
Commissioner Barker has a question.
COMMISSIONER BARKER: Thank you, ma'am.
Q COMMISSIONER BARKER: I just have a quick question for Mr. Thomsen. I just wanted to clarify -- or clarify my understanding of what you had mentioned in response to one of the questions from Ms. Peddlesden. She had asked you if there were any technical concerns with the change to operating MOP in your applications with the change in operating pressure to -- to 5,500 kPa. And I thought I heard you mention that there was a minor risk reduction, but then you had mentioned that there could be some increase in operational downtime and a potential for scale plugging.
So I didn't know if the risk reduction was related to those things because that sounds like a risk increase to me, but I wondered if I'm muddling up what you had said.
A P. THOMSEN: The risk reduction is with respect to ISH's concerns about steam communication with the Wab B gas.
Q Okay.

A And so that minor risk reduction is with respect to the confinement strata integrity.
The -- in a sense, I mean, the consequence of this is there is less operational flexibility for the SAGD operations, and we would not expect this change in the long-term maximum operating pressure to have any impact on scale precipitation, so that's just -- it's an example of a type of unplanned event that can occur with SAGD well operation.
Q Okay. So -- so lowering the maximum operating pressure would not have the potential for a scale plugging or increased downtime?
A No, they're independent.
Q They're independent. Okay. Okay.
So the technical concerns you don't have any real technical concerns with regard to lowering the -- reducing the -- the operating MOP?
A I don't have any technical concerns as far as confinement strata integrity. There are some -- if you can just give me a moment, I just want to confer with my production colleague.
Q Yeah. Sure.
A Okay. So the reduced operational flexibility has to do with pressures that we can apply to the well and some upset operating conditions, and so, for example, if there was scale precipitation inside a well, inside a

tubing, or inside the liner, and we needed to do a stimulation to dissolve some of that scale, it would reduce the pressure that we could inject an acid at, let's say.

Does that answer your question?

Q It does, yeah. Thanks. So -- yes, that's clear for me. Thank you very much.

COMMISSIONER BARKER: Thank you.

Q COMMISSIONER CHIASSON: So I have questions on a couple of topics, and I was going to say I'll go with the first one, which is actually likely a set of questions, and I can't point to a particular person because this arises out of what we heard yesterday in evidence, and we heard various different terminologies used in relation to time. And so I'm wanting to just get some clarity around that to understand whether all these different terms we've heard are meaning the same thing or not, and then I have some follow-up on that.

So part of it, I think -- and initially, Mr. Lavigne, you had talked about CNRL's definition for barriers and baffles and you mentioned that CNRL's definition for a barrier was that it was not -- something that was not permeable to steam over the life of operations. And then you referred to the life of operations again but also made reference to life of the KN08 and KN09 pads and life of the drainage boxes. And then later on I think both Dr. Boone and Mr. Barland made reference to lifetime of drainage boxes, and so I'm wondering, are those all the same thing?

A J. LAVIGNE: So, firstly, just for clarification, the definition of barrier and baffle that we used was actually out of the Fustic paper, which -- which was presented in a KN06 decision report and so we -- for continuity, we decided to follow those -- those same definitions.

So sort of to this second part of your question, the -- over the life of the boxes or pads or operations -- I think we're all meaning the same thing -- over, say, the 20 years or 25 years of SAGD operations on those pads.

I'll invite any of my colleagues to correct me.

A G. IANNATTONE: I was just going to say I think we've had various numbers in -- in the life of a pad definition or drainage box. I think it was as low as 10 or 15 years and maybe as high as 20. I think what we're talking about is typical. Like, we have a lot of drainage boxes that go beyond 20 years, and we have, you know, others that are shorter, 10. So, like, we have the whole spectrum. So that's why, you know, the definition of a typical life span of a drainage box is -- it's not an exact number. It's a thumb wag.

Q Okay.

A It's a range.
Q Yeah. So that's -- that's part of what I was wanting to understand is with all these terms, are we all talking about the same thing in terms of after this when the Panel sits down to look at it, are we comparing apples to apples and not apples to oranges, to be quite frank.
So then, similarly, because Mr. Ollenberger talked about 20-year delay in relation to valuation of the gas resource and talked about on the assumption that the pool would not be able to produce until the bitumen resources at the Pads KN08 and KN09 are completed. So, again, is that the -- is that the same thing in terms of -- when you're talking about that type of timeline and the resources being completed, same thing as lifetime of the operations, lifetime of the well pad or of the drainage boxes?
A D. OLLENBERGER: Yes. The 20 years is with respect to what would be considered probably a normal operating life span of a SAGD pad, but of these pads specifically, not necessarily any future pads.
I guess just to clarify also, there is a probably high likelihood or strong likelihood that KN08 and KN09 will not necessarily start steaming operations at the exact same time.
Q Okay. And just in the broad range -- and I understand

what you say about being a thumb wag or whatever, but we've got 10 to 15 years, up to 20 years; I may have seen something when I was looking at the transcripts that had mentioned 25. So are we looking 10 to 20? Is there -- are there goalposts, like, broad goalposts that you can point out to us, or does it depend on who's talking about what?

A I think probably the difficulty arises from -- though Dr. Boone did say that SAGD is an established technology, and that is true, there's not yet, to my knowledge, a SAGD pad -- definitely I don't think at CNRL or Canadian Natural -- that has reached its final life. And so I think that's where it's relatively hard for us to nail down one number there. We're using 20 because I think at our Jackfish asset we have our A pad that is over 20 years of life span and still producing today.

Q Okay. So enough about -- talking about timelines, then. We'll move on to my second question.

COMMISSIONER CHIASSON: And so for this, Ms. Wheaton, could we pull up -- let me just get the document number right. So 50.002, PDF 44, and I'm interested in Table 5 on that -- on that page.

Q COMMISSIONER CHIASSON: So this is the table with the cost estimates, and to some extent some of Mr. McLeod's questions crept into where -- where I was looking to go with it because he asked earlier today in relation to the DFIT estimate, and Mr. Thomsen had referred to this morning in terms of DFIT could cost a range from 375,000 to 1 million plus, and we see that it's the -- the 1 million figure here. And so I'm interested in understanding in relation to this, and I don't know whether anyone on the witness panel was who prepared this table or not, but in terms of understanding, with these various estimated costs both for ISH requests and CNRL commitments, are these all subject to ranges in terms of a high and a low possibility? Let's start with that.

A Yes. I mean, these are estimates. Obviously there's not budgeted numbers. Any work in the KN08 and KN09 area we have -- as Mr. Iannattone mentioned, we need certainty on development before we can proceed with developing our assets. So there's always, you know, a time component and inflationary pressures that could change these costs. I think these are generalization costs. There are probably ways to have these costs be reduced. There's probably also ways that these costs, as often happen in the oil and gas industry, could go well above these costs.

Q And so then how -- can you talk about how you settled on costs -- the costs, then, in terms of if there's a high and a low? What -- what got picked? Where --

where -- what's --
A We used our best reasonable estimates today.
Q Okay. All right. And so then I guess just -- and so that's for both the ISH estimates and the CNRL estimates there. So I'm a little interested, then, in terms of -- as well because you mentioned in terms of potential for cost savings, that type of thing, and the other one that -- that catches my eye significantly is essentially if we look at the first row running across under the grey about ISH request for minimum one observation well per pad, which you would assume, then, would be two pads, and it's saying 2.4 million. And next to it you've got CNRL commitment in terms of converting -- converting wells, which would appear to come out to 995,000. And so I'm just looking to understand that a bit better because here you're talking about more wells, and I realize it's conversion, but that -- you know, 2.4 million seems to me to be a significantly higher number.
A Yes. So in ISH's submission, they did give an example of what they thought was a sufficient observation well where I believe they described a full SAGD observation well with external cemented gauges and thermocouples. Those wells are our most costly wells, and we would not have any existing today that would be able to provide the data that ISH requested. So that is where the

large number of the $1.2 million per well does come from.

When you look at our estimated costs for the CNRL commitment, that's where we would convert the 10-34 well plus adding surface equipment for what's estimated at $115,000 -- sorry -- yes, $115,000. Further, we said we have the existing 100/1-3, which is a standing cased well, so there's no additional cost to drill that well. To convert that well and add surface equipment, that would be where we would be able to go in and hang a gauge and perforate and monitor the Wabiskaw B gas. That would be an additional $90,000 as estimated.

And then if you assume that we needed to go to KN09 and provide a new standing cased well for $700,000 approximately and then convert that well for the previous mentioned $90,000, that is how we add up to the $995,000.

Q Okay. And just -- just -- perhaps I misunderstood the submission that CNRL filed on January 23rd, so the reply submission because my understanding was that the suggestion was on the future gas monitoring well on the KN09 that that would be a conversion out of a -- out of a stratigraphic well or out of a -- any number of stratigraphic wells that you would be planning to -- to do over the KN09 -- the KN09 area?

A Yes --

Q Am I wrong?
A -- that's correct. It would be a new well.
Q Okay. So this is taking into account the brand-new cost for that well that you would be planning to drill anyway otherwise for -- for -- for stratigraphic purposes?
A Potentially. We would not necessarily be leaving it as a standing cased well, so there is additional expense to that. And I guess the point would -- being that in our submission we felt that the existing 100/1-3 well and 10-1 well do provide sufficient monitoring.
So, yes, if we wanted to be, again, reducing costs, you could in theory say we were going to convert an OSC well that was not going to be cased, and there would be some additional savings if you applied that full value.
Q Okay. Thank you. That was what I was looking to now, and --
COMMISSIONER CHIASSON: You're good?
Okay. So that is it for the Panel's questions.
So now, Ms. Jamieson, I guess we're looking to you as to whether or not Canadian Natural is looking to do redirect?
J. JAMIESON: Yes. So I am -- good afternoon, Commissioners. I am very keenly aware that I am between -- my questions are between everybody

going home after a very long day. So -- but I would like to do -- I think I can be done in 10 to 12 minutes, provided my panel cooperates. So I would propose to -- if you can allow me, I would really like to get it done, and then the panel can be released for the evening.

G. IANNATTONE: Yeah. Ms. Jamieson, we have the undertaking -- the answer to the undertaking as well.

J. JAMIESON: Yes. That can come back in tomorrow, though; correct?

G. IANNATTONE: We --

J. JAMIESON: I think --

G. IANNATTONE: We have the answer tonight, if you want it.

J. JAMIESON: Oh, you have it right now? Okay.

G. IANNATTONE: Yeah, we have it. So it'll take 30 seconds, I believe.

J. JAMIESON: Why don't we start there. That's great.

G. IANNATTONE: Okay. So I think the undertaking was -- the question was: Does Canadian Natural have any reserves currently booked to the Kirby Upper Mannville II gas pool? And the answer to that question is: No, we do not have any proven or probable

reserves booked to that pool. The reason we don't have reserves is because under the co-key [phonetic] -- the rules is that we don't have line of sight to the regulatory approval. So although -- although the reserves will be produced at some future point in time, we can't predict when. So no reserves, no value.
(UNDERTAKING 1 FULFILLED)
COMMISSIONER CHIASSON: Okay. Thank you.
ISH, anything that -- that you'd have out of that? Because I know we did -- you did indicate that you'd closed off your questions, subject to anything that might arise out of the undertaking.
M. RILEY: My apologies. If we could please consult.
COMMISSIONER CHIASSON: Okay. All right. Let us know, please.
M. RILEY: To confirm, ISH has nothing further.
COMMISSIONER CHIASSON: Thank you very much.
All right, Ms. Jamieson. Let's proceed with your redirect, then.
J. Jamieson Re-examines the Canadian Natural Resources Limited Witness Panel
Q J. JAMIESON: Okay. Good afternoon, panel.
Dr. Boone, I'm going to start with you. You received a number of questions from Mr. McLeod --

that's ISH's legal counsel -- I believe -- well, mostly yesterday -- a little bit today -- regarding your qualifications to provide the different parts of your assessment on the hearing issues. Can you very briefly speak to why you are qualified to provide the assessment that you did in terms of your professional credentials and experience?

A T. BOONE: Sure. So my original PhD thesis was in the area of rock mechanics, but it was actually fracture propagation in pore elastic materials. It was sponsored by Schlumberger. So I developed a fair bit of expertise in fracture mechanics and geomechanics at that time.

I -- I subsequently moved to Imperial Oil's research lab, where I was mostly working in steam-induced fracturing. We had some containment issues at the time, so I spent considerable part of my career working caprock integrity, potential fluid losses outside of zone for various problems and developed monitoring techniques that were applied in the oil sands industry.

And then I started doing a lot of work in pilots. I was running the pilot program, so drilling different wells, doing types of recovery processes. I evolved into becoming a reservoir engineer.

Spent some time in Houston doing reservoir simulation and in Norway as well doing reservoir simulation, drilling wells, that type of thing. Came back. I was the research manager for Imperial Oil, oil sands recovery research is what we called it, but at the time we were mostly working on solvent processes, SAGD for -- solvent-assisted SAGD for the Athabasca. We were modelling it in the lab, running pilots at Cold Lake but also other solvent processes for Cold Lake.

And then after that role, I -- I moved on to work for ExxonMobil as the senior EOR reservoir engineer worldwide, so I went around the world looking at various projects and --

Q And in all of that time, have you provided other risk assessments like the one that you provided on these hearing issues?

A Risk assessments within Imperial Oil in particular is -- I'm going to say it's a daily process. So at the research lab every project that we have, we did risk assessments. For everything in the field, we did risk assessments. I mean, one good example is for the Nabiye project. We encountered -- well, CNRL had some issues north of us. Just as we were going to -- to go drill up the project, we convened a large team of experts, or I should say a modest team of experts, five or six of us, evaluated the caprock integrity, and based on our risk assessment, added four or five more

wells to the program at the last minute, which wasn't well received by everyone but technically was certainly justified.
Q The risk assessments that you're talking about, do they include using the APEGA guide and model that you have provided in your report?
A Similar. I would say the process was the same. I use the APEGA guide, and, of course, working for Imperial Oil, every company has its own risk assessment process. So they're all somewhat different but fundamentally they're the same.
Q Thank you.
You were also asked about whether you had any other clients other than Canadian Natural during the past year. If the question had been posed the last five to ten years, what would your consulting practice have looked like? How would you have responded?
A Since I retired? I have done some consulting for a geomechanical company. I've done another hearing like this for another company. I was hired in a patent infringement lawsuit related to SAGD in in-fill wells that took a year and a half. I was the -- the non-infringement expert.
Q Okay. You also received a number of questions with respect to how you had sourced the information and -- that you relied on in your report, which included

receiving information and data from various Canadian Natural personnel.

So the question is: Can you just briefly review your methodology for collecting and analyzing the information and data?

A At the high level -- so I went and looked at reports and papers and things out there that -- that recommend how to assess caprock, and generally they say you're going to end up with a qualitative answer. It's geology. You're never going to be able to definitively say, No, this is a hundred percent going to seal whatever material you're trying to seal, whether it's CO_2, steam, or waste.

And so generally the recommendations are, you know, develop a list of all the factors that might apply and assess them all. And that's things like -- and that's why I had that table at the beginning. So do you have enough core wells in the area to make a reasonable assessment? Do you have enough wells for FMI, that sort of thing? What other evidence is out there?

So what I tried to do was take a comprehensive approach like that. I also looked at the AER directives and that guided some of the choices of the parameters I looked at. And then CNRL sort of more or less gave me open access to talk to anyone in their organization and seek out data that I thought was appropriate and needed to be considered.

Q And during that process, which included contact with Canadian Natural staff, how did you maintain your independence?

A I -- you know, I didn't ever think it was a problem maintaining my independence. I'm -- I am independent. These are my conclusions. I recognize that, and I need to own them, and, you know, I -- I -- those are my professional opinions that I have provided in the reports.

Q Thank you, Dr. Boone.

Mr. Sverdahl, yesterday you were asked a question about whether faults or fractures can be seen on seismic. I think it came up again this afternoon, and you did acknowledge that small faults and fractures cannot be seen on seismic, so "subseismic", we heard that term as well.

Can you briefly confirm, please, that if small faults and fractures cannot be seen on seismic, what is Canadian Natural's workflow for identifying small faults and fractures?

A S. SVERDAHL: We review all -- all other data such as core data and image logs to understand if there's fractures or fracture intensity within the areas that were --

Q Sorry. I'm going to stop you because can you just bring your mic closer to you. You're soft spoken and it's just -- speak right in there. Thank you.
A Yeah. Our primary method of understanding if there's faults and fractures -- small-scale faults or fractures is to review all of our core data, all of our image log data. We also look at the seismic in context of areas where we see things like sags from differential compaction, and we test those areas as appropriately with strat wells and run them, either core and/or image logs, through those features. So we investigate areas where we believe there could be fractures or faults that aren't necessarily detectible on the seismic but we know they may exist. They're in the areas of greater differential compaction. So, yeah, it's an integrated workflow to understand where they -- they may be, and we -- we test these features as necessary with getting more direct geological data.
Q Thank you. Last question: Mr. Lavigne, so Canadian Natural was asked a series of questions at the end of yesterday, actually, regarding -- and then I believe AER legal counsel came back to it, but it had to do with Canadian Natural's use of, first, third party analyzing GCMS data using Schlumberger's lab. Do you recall that set of questions?
A J. LAVIGNE: Yes.

Q Okay. The question for you: Can you please clarify Canadian Natural's workflow for integrating GCMS data into its confinement strata interpretation.
A Firstly, at the sampling level, Canadian Natural strategically picked samples in cores to test stratigraphic units that we have correlated to other wells, and -- and then we apply industry standard display techniques and plot it consistently with -- sorry.
Sorry. So the GCMS, to reiterate, is -- it's one part of a much bigger workflow, and so we've mapped units, we assess logs, and, as I mentioned, we pick stratigraphic surfaces that we try to -- that we want to test; particularly in the reservoirs, we're very concerned about steam rise. There's tremendous economic implications for barriers and baffles within the reservoir. So we start to -- we start there and then -- and then we apply the sampling up through the confinement strata to test the longer-term containment, but we -- we have a third-party vendor conduct the actual analysis, but then we have the expertise in-house that -- that we use industry standard techniques to plot and analyze the data, but it's always layered back to our stratigraphic foundation.
Q Thank you.
I see Mr. Sverdahl. Do you have something to add?

A S. SVERDAHL: I think Mr. Lavigne covered most of it. Like he said, we do all of our mapping, you know, based on -- on the available well log data, core data, image log data. We integrate surfaces as we can with seismic, and we layer on the GCMS data to all of our other vast geological understanding. The analysis for the GCMS data, the lab analysis, is done by Schlumberger in-house, and we do the interpretation of that lab data that is provided to us and layer that into our -- our geological models of both the reservoir understanding and the confinement strata.

J. JAMIESON: Thank you, Commissioner Chiasson. Those are all my questions. Thank you.

COMMISSIONER CHIASSON: Thank you, Ms. Jamieson.

So at this point, and I'm just going to ask you gentlemen not to all jump up, but as a witness panel you are -- are released, so we are done with you there, but because I do have a couple of closing comments, and that it would be easier if you wait 'til we close it off for the day.

So I realize we are clearly -- clearly behind and that we were -- we were scheduled initially in the schedule for ISH to start direct evidence today. I'm assuming that you would prefer to leave that 'til tomorrow morning and start off with your -- with your direct tomorrow morning.

M. RILEY: Certainly, yes.
COMMISSIONER CHIASSON: Yes. Okay. And we're well aware that the concern is that Dr. Chalaturnyk has -- has timing restrictions in terms of that he's not available on Friday, so we need to ensure that cross-examination in relation to any of his evidence from both CNRL and any questions that we have from the AER occurs tomorrow. So we will make sure that that happens.
Is -- and so I guess I'm just testing in terms of from the parties' perspective, is there a desire to start earlier than 9:00 tomorrow or to look at how -- how we can adjust the day as it goes along?
And -- sorry -- I guess in that, I should check and make sure if our court reporters would be available earlier if that was an option. Yes. Okay. I'm seeing a nod yes from them, but ...
M. RILEY: I don't want to be difficult, but earlier is not really a possibility for us because we have panel members with children and some obligations early in the morning.
COMMISSIONER CHIASSON: That's absolutely understandable. So that's not -- that's not a problem. We just thought it was something that -- that we would test.
So that's -- that's fine. We will start -- we

will start at 9, and we will look to -- look to see, I guess, how -- how the day flows. I guess I would test with both parties in terms of -- so clearly today we ran a little later than planned. Is there the flexibility there in terms of running -- because right now what we had projected for tomorrow was 'til just before 5:00. Is there the flexibility or the interest in terms of running a little longer tomorrow if need be?

M. RILEY: We will make arrangements to make that possible if we need to.

COMMISSIONER CHIASSON: Okay.

M. RILEY: We will also overnight review the evidence we intended to present and see if there isn't some time economics to be gained.

COMMISSIONER CHIASSON: Thank you. We appreciate that, but we don't want to put the squeeze on you otherwise because we -- we recognize that things have -- things have a way of growing generally, aside from what -- what you have got, so thank you.

So we'll be -- we'll be alive to that tomorrow. So we will confirm that we resume tomorrow morning back here at 9:00. As we reminded everyone yesterday, the rooms here are not secure. I am assuming that the breakout rooms are not secure, so please make sure that you take all your belongings with you 'til tomorrow, and thank you all for your participation today and, gentlemen, for your patience sitting in those seats for -- for -- for two days. We appreciate it.

And actually also we would like to provide the feedback to everyone. Thank you for making the effort to use the microphones today and speak clearly. It made a big difference for us. So thank you so much.

(WITNESSES STAND DOWN)

PROCEEDINGS ADJOURNED UNTIL 9:00 AM, FEBRUARY 8, 2024

CERTIFICATE OF TRANSCRIPT:

We, Sandie Murphy and Sandra Burns, certify that the foregoing pages are a complete and accurate transcript of the proceedings, taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Calgary, Province of Alberta, this 7th day of February 2024.

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Sandie Murphy, CSR(A)
Official Court Reporter

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Sandra Burns, CSR(A), RPR, CRR
Official Court Reporter

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