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

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(PROCEEDINGS COMMENCED AT 9:04 AM)

Opening Remarks

COMMISSIONER CHIASSON: Okay. Good morning. And welcome back to Day 4 of our hearing. And so the usual reminder about the video cast and that you may show up on the video cast if you're in the room, and if there's anyone new -- I would assume anyone who has had concerns would have already brought them up to Mr. Lung, but if you have concerns about the potential that you may appear on the video cast, please speak with Mr. Lung.

And I know I mentioned this at the first day of the hearing and I realized because I just had to do it before I sat down is please remember -- check that all your electronic devices, phones, computers, et cetera are set to "silent" because I almost made that mistake just this morning. So please -- please make sure of that.

Otherwise, I believe -- unless there's anything to start off with this morning, we are continuing on with

CNRL cross-examination of ISH's witness panel. So if there's nothing else, then please proceed, Ms. Jamieson.

J. Jamieson Cross-examines the ISH Energy Ltd. Witness Panel

J. JAMIESON: Thank you. Good morning, Commissioners, and everybody else in the room.

We do have a number of questions, an hour, an hour and 15, I believe that's what we were allocated. I suspect we're going to use it all.

Q J. JAMIESON: I'm going to start with Mr. Vickerman from -- yeah. You -- you gave a presentation yesterday on the image logs, interpreting image logs. We found that very helpful. Thank you. Appreciate it. And can you just confirm that you only, in the end, interpreted two image logs?

A K. VICKERMAN: Yeah, that's correct.

Q And as you're -- or are you aware that Canadian Natural had provided 11 image logs to ISH that could have been reviewed? Are you aware of that?

A Yeah.

Q Were you involved in the selection process of which -- of the two -- which of the 11 to review?

A Yeah. So we looked at the images that were available, and we picked out the ones that we could see some fracture.

Q Okay. So you helped with that?
A Yeah.
Q Okay.
A But it was looking at 11 images in an hour, so it wasn't a --
Q Understood.
A -- it wasn't a deep delve into them.
Q Okay. But you were involved. Okay. Thank you.
And now if I understood your evidence correctly yesterday, you said that ideally you would have received the DLIST -- DLIS --
A Yeah.
Q -- logs to conduct your interpretation. I understand that stands for digital log interchange standard; is that correct?
A That's correct.
Q Okay. Which you didn't receive -- and we're all aware of that -- and -- but what you did receive was a PDF of a TIFF file; is that correct?
A I don't know that it was generated from a TIFF file. It was a PDF, and the part of the PDF that we used was a -- like a TIFF file in that it's a -- an image array. It's -- it didn't have any orientation. It just showed where the pixels were particular colours.
Q Okay. Thank you.
When you do these interpretations, you're agnostic

to the depth of the issue in question, and that's how you approached this one as well?

A That's right. You usually pick from bottom up and then review from the top down and then change the scale and do another review through.

Q Right. Okay. Now, notwithstanding you didn't receive the format of the image logs that you would have liked ideally, you were still able to provide some interpretation, and you have a level of confidence in that interpretation?

A Yeah. The data that we had to work with is -- if you imagine that the -- a DLIS might be a hundred percent confidence when you -- maybe if we had had an image of the static image and the dynamic image that we could have cropped both, that might have been a 95 percent or something like that. And what we had, there will be some intervals that are much lower confidence that could have had more fractures or could have had fewer fractures.

Q Okay.

A And so, you know, maybe it's a 90 percent confidence. We -- it was still a fairly decent image over those two, and I was confident -- certainly high confidence in some of the features that we saw and moderate -- confident enough in -- in the others.

Q Thank you.

J. JAMIESON: Court reporters, are we speaking loud enough? You're -- thank you.

Q J. JAMIESON: In your report in your executive summary there, you generally characterize what you did identify as "sparse" or "low density". Can you confirm that that was your overall conclusion?

A That's correct.

Q Thank you very much, Mr. Vickerman.

These next set of questions are for you, Mr. Barrie, please. And -- was that me? Ms. Wheaton -- is it Ms. Wheaton? No. It's somebody new everyday.

COMMISSIONER CHIASSON: Sorry. This is -- this is Ms. Arruda. Sorry.

J. JAMIESON: Ms. Arruda.

COMMISSIONER CHIASSON: I apologize. I should have introduced her.

J. JAMIESON: Thank you. No worries.

I know that there was a lot of requests to Mr. Lung, and he wasn't in control at all. That was the witness training we did. Sorry. Okay.

So, Ms. Arruda, if I could please have Exhibit 44.10 up on the screen, and it is Figure 1 -- oh -- sorry -- PDF page 7, Figure 1.

Q J. JAMIESON: And can you please confirm, Mr. Barrie, that you prepared this map?

A B. BARRIE: Yes, I can confirm that.
Q Thank you.
And can you please describe what it shows, and I think in particular the blue lining on the map?
A Yes. Can I get the mouse, please? Yeah.
Q Oh, that's a good idea.
A So this is a map of the mid-B1 mudstone, and the values that you see plotted here are my estimations of the thickness of that unit, which vary on the flanks from 42 to 34 and then down to 16 centimetres, et cetera. It gets much thinner until you move to the centre. The area within the blue line is where I've plotted zeros, which is where, in my interpretation, I have mapped that the mid-B1 mudstone is absent, which is adjacent to the area that CNRL has mapped as absent, which is shown in green.
Q Very good.
And I'm going to ask you -- I'm going to take you to another figure, but can we agree that we'll call, you know, that your blue polygon, and what's inside is your interpretation that there's no mid-B1?
A That's correct. There's no mid-B1 mudstone within that blue contour.
Q In your -- in your opinion? Okay.
A Yes.
Q Thank you.

J. JAMIESON: So if I could please now, Ms. Arruda, have Exhibit 50.003, Tab 7. And if we could -- thank you. That's the image. If you could expand -- you see the yellow in the middle of the -- those wire logs? Yeah. Just a -- just so that it's really readable. Maybe one more expansion. Perfect. Thank you very much.

Q J. JAMIESON: Okay. So what we've got here --

J. JAMIESON: Actually, I think I missed a step. So if we could keep that one handy, but if you could go to Exhibit 32.03, page 5 of the PDF, Figure 1. Yeah. Perfect. Thank you.

Q J. JAMIESON: Yeah. This is the other piece I believe, Mr. Barrie, comes from your report, and you spoke to this yesterday, and if we could just confirm that the core photo displayed is -- is representative of the mid-B1 mudstone?

A Yes, that's my interpretation.

Q Okay. All right. Can you just describe for us --

A Can I --

Q Oh.

A Sorry for interrupting.

Q Sure.

A I agree that the interval between the red pins, so the area outlined with the green double arrows, is the

mid-B1 mudstone. The rock below it in the image and the rock above it in the image is not the mid-B1 mudstone.

Q Understood.

A Okay.

Q Can you just for us describe how you see that lithofacies of the mid-B1?

A How do you mean "see"?

Q The character of it. Can you describe the character of the mid-B1 from a geology perspective?

A Okay. In brief -- typically it's a medium to dark grey mudstone without mud sand. It has fine bioturbation burrows. I think that's it.

Q Thank you. No, that's perfect.

Do you acknowledge that the mid-B1 is a regional marine flooding mudstone? Is that how you would characterize it?

A I agree with the characterization that's been provided by CNRL, and when I look at that interval there, it looks like a marine flooding mudstone, yes.

Q Okay. Thank you very much.

J. JAMIESON: Now, if we could go back to 50.003, Tab 7. And if you wouldn't mind, please, Ms. Arruda, enlarging it the way you did the other time. That's perfect. Thank you very much.

Q J. JAMIESON: We've seen this cross-section

before -- Mr. Lavigne spoke to it -- and if you -- it represents Canadian Natural's interpretation of -- in the very middle, this is the 100 of the 1-3 well -- and this is the Canadian Natural's view of the world, right. They see this -- their interpretation is that it's just cut out very locally there for a tidal channel. You're familiar, right? You're aware that that's Canadian Natural's view?

A I'm aware of that.

Q Thank you. Okay.

If we could look to the left -- and this was a nuance I had missed, so I'm going to read it out, but the well to the left is a 1-3 as well, but it's the 1AA well, and if you can just look at the dimensions at the top line, it says 215 metres, and that represents that that well is 215 metres away from the other 1-3 well. Do you see that, sir?

A Yes, I do.

Q Okay. Thank you.

So if you could just confirm that in that well, so the 1AA/1-3 well, if you -- maybe you can do it from here, but can you confirm that the mid-B1 mudstone is present in that well?

A No.

Q What do you see that --

A What do you mean what do I see there?

Q Well, Canadian Natural sees the mid-B1 in that -- in that well. They're identifying it in the green, or it's between the upper -- the green, so the upper B1 regional sequence, there's a layer between that and the lower B1 regional sequence, and they see that as the mid-B1 sequence. Do you concur?
A I understand what you're saying about their interpretation, but there's absolutely no way on logs to see the mid-B1 mudstone when --
Q That's core?
A Particularly on this well log. It has to be thicker to see it. I have seen this core, and so the core in the photo isn't shown here, but, yes, the mid-B1 mudstone is present in core in this well.
Q I think -- if I can get a moment.
A Yeah.
Q I think I'm bungling this question.

I know where I went wrong.

J. JAMIESON: If you could, Ms. Arruda -- like, it's zoomed out. If you could zoom back in the core photo to the left. So we need to correlate the core photo that's there. So to the left -- sorry -- the other direction. There. Okay.

Q J. JAMIESON: So the red arrow to the green on the log is -- is connected to the mid-B1 from the core photo, and do you see the mid-B1 in the core

photo?
A Yes, I do. It's circled with the red ellipse.
Q Thank you.
All right. Let's go to the other side. So the third well on the right-hand side is the 1AC/5-2 well, and, again, there's a red arrow pointing to the -- you know, the regional sequence, and it is correlated with a section of the core that is the mid-B1. Do you see that there on the right corner?
A I see that there's a circle pointing to where you're indicating the mid-B1 is present.
Q So is your -- do you recognize the mid-B1 in that core photo?
A I can't say as I do. I mean, there is a grey shale that's circled there, but I do not recall seeing that core, studying it to be sure. If you want, I can say that it does look like the mid-B1 mudstone, but I'm not sure that it is the mid-B1 mudstone.
Q Okay. That's fair. And that's --
A Okay.
Q -- sufficient for our discussion. If you look to the top third well over, the logs, it says "1AC/5-2", and then, again, in between that well and the middle well, you see the 217 metres. So is it your understanding or do you concur that that well is 217 metres away, the one --

A Yes.
Q -- that Canadian Natural is showing, the mud B?
A Yes.
Q Okay. Thank you.
Sorry. That was a little bit clumsy, but we got there.
A A. LAGISQUET: Excuse me. Can I -- can I please confer with my colleague for a second on this question?
Q Sure. Yes.
A B. BARRIE: My team leader has asked me to tell the hearing room that I'm not sure that I have looked at that core.
Q Understood.
A Okay.
Q And, yeah, I really was asking you to visually identify or see if you thought that was the mid-B1?
A Can I --
Q -- from the core photos?
A And I know that that's what you were trying to do, but if you look at that same photo, there's -- if I may, just point -- is my mouse active? Yeah. So that's what you're calling the "mid-B1 mudstone". There's also some other mudstones here and there which are not within that interval that you circled that look like they could be mid-B1, but they're not, so it's

difficult for me --

S. PEDDLESDEN: Mr. Barrie, for the record, if you could just verbally say where you put the mouse, so to --

A Okay.

S. PEDDLESDEN: -- the far left.

A B. BARRIE: So if we are looking at the --

A A. LAGISQUET: Can we please zoom in on the core so that he can point to the pointers on the core? That would be easier to record.

A B. BARRIE: So I'm -- I'll start by pointing out the ellipse in red, which is what you're asking me to tell you if that's the mid-B1 mudstone. There's also some mudstones below that, which are on the far left side of this photograph panel, which look like medium grey shales that may not -- that -- you know, it's hard for me to be certain what mud that is. And there's also some muddy beds up here that it's hard for me to be certain of.

But to help you get on your way, so to speak, I will acknowledge that this could be the mid-B1 mudstone.

Q J. JAMIESON: Thank you.

A Okay.

Q Just a follow-up question: Looking inside the red circle, can you visually estimate the percentage of

mudstone in that interval?
A It's difficult for me to estimate on a core photograph across the room the -- you've asked me the volume of shale or how thick the shale is?
Q The volume of shale, yeah. So VMI?
A It's difficult to estimate, but for the sake of moving along here, it's high. There's a lot of shale there.
Q Okay. That's sufficient?
A Okay.
Q Thank you very much for cooperating on that.

Let's move to, if we could -- oh, I think we should just -- these are just questions based on your evidence -- your direct evidence yesterday.

You made a statement -- and we did look it up in the transcript. I'll read it out to you just to refresh your memory. You stated: (as read)

> We estimate the volume of shale in the so-called confinement strata to be approximately 35 percent. In other words, 65 percent of the material in the confining strata is sand, porous, and permeable sand. The volume of shale, the 35 percent, is much lower than other SAGD developments where the volume of shale is typically 60 to 80 percent.

You recall that statement, sir?
A Yes, I do.

Q And based on the cores that we just looked at, is that an accurate statement, or would you adjust it? Just based on -- you just used the word "high", and yesterday you used the word "35 percent", but just based on the images we just looked at, what would you -- how would you characterize the percentage?

A Okay. So, first of all, when you were asking me to estimate the volume of shale, I understood you to be asking me about the volume of shale within the red ellipse in the middle of the screen, which is of the mid-B1 mudstone. And I indicated that the volume of shale is high there.

My comment yesterday was about the entire package of the confining strata, which includes from the top of the SAGD pay to the base of the Wab B. And if you look in this photo, you can see that there is a high percentage of sand in that interval. All the dark brown colouring here is sand. It's not mudstone.

Q Did you conduct any log-based analysis to come to that conclusion?

A No, I did not.

Q Have you conducted any mapping over other SAGD developments to support that statement?

A I have viewed hundreds of maps of that interval over various SAGD projects in this basin.

Q Okay. Thank you.

J. JAMIESON: If we could -- let's see if we're still in Exhibit 50.003. I believe we are. Tab 5, please, Ms. Arruda. And if you could just zoom out for a moment to the map in the centre, we'll start there.

Q J. JAMIESON: Okay. So this map, my understanding of it is the -- Canadian Natural had taken -- had drawn your blue polygon over their isopach map. Do you concur that blue polygon represents your -- your mapping outlining of where you believe the mid-B1 is present?

A No.

Q No?

A It's where it's absent.

Q Sorry. Yes. So present on the outside?

A Correct.

Q Absent in the middle?

A Correct.

Q We're on the same page. Thank you. All right.

So I'm going to -- I'm going to refer to it as "the blue polygon", and I'm going to talk about inside or outside the blue polygon.

J. JAMIESON: So if you could zoom out just so that we can catch the core that's on the right side, Ms. Arruda. It's the 1AA/11-2 well. It's on the centre right.

Q J. JAMIESON: And I believe, Mr. Barrie, you spoke to this one yesterday.

J. JAMIESON: And if you could just zoom out a bit. So it's the well -- let me get the right one. It's third up from the bottom on the right. So, yeah. Right there, please. Yes.

Q J. JAMIESON: Do you recall that yesterday? I believe, Ms. Barrie that -- Mr. Barrie, that you identified or acknowledged that in that well, the 11-2, you were seeing mid-B1 in the bottom -- on the bottom row of that log on the left side; correct?

A Yes. I was seeing the mid-B1 mudstone in that photograph.

Q Good. Thank you.

So I want to move to the one just below it -- sorry. Before we go there, that well, if you follow the line to your blue polygon, sits just outside the blue polygon?

A Correct.

Q All right. Thank you.

So then if we look to the core just below it and in this one, do you identify or see the mid-B1 midstone [sic]? It would be the top row to the right-hand side?

A This is the same photograph you showed me a few minutes ago, and, again, I can't recall if I've seen this core, and I can't say for certain that is the mid-B1 mudstone

or not. However, for the sake of moving along, I will agree that this looks like rock that could be mid-B1 mudstone.

Q Okay. Thank you.

I didn't -- the identifier for that core is under the photo, the core photo on the right-hand side, so that's the 1AC/5-2 well, and you're saying it could be. And if we follow the black line into your blue polygon, do you see that the location of that well is in almost the centre of your blue polygon?

A Yes, I see where the arrow points.

Q Okay. Thank you very much.

If we could now, I'd like go up to the corner left of this figure. Top -- yeah, very top corner on the left-hand side, and that well identifier at the top, sir, is 1AB/5-2. Do you see that?

A Yes, I do.

Q And, again, Canadian Natural identifies mid-B1 mudstone. I believe it's on the right-hand side of that core on the upper level, and do you concur that that too is B1 mudstone?

A No.

Q You disagree on that one?

A I disagree on that one.

Q Okay. But just for the argument's sake to complete, if you follow the black line, you would agree with me that

the location of the well is in the middle of your blue polygon; correct?

A As drawn here, yeah, it looks like the arrow points to the middle of the blue polygon.

Q Thank you.

Okay. We're going to do the last one; you'll be relieved to find out.

J. JAMIESON: If you could, Ms. Arruda, go up to the top right-hand corner, far right. There's another core up at the top, and if we could just zoom out a little bit, and it's the -- the identifier is the 1AB/11-2 well.

Q J. JAMIESON: Do you see that one, sir?

A Yes, I do.

Q Okay. And, again, far right-hand side, Canadian Natural identifies mid-B1 mudstone, and would you concur that that, in fact -- just on a visual basis, that appears to be mid-B1 mudstone?

A No, I do not concur.

Q Okay. Again, let's follow the arrow down. You would concur, though, that the location -- that that well is within your blue polygon; correct?

A Yes. If it's plotted correctly.

Q Thank you.

I believe those are all my questions for you. Thank you, Mr. Barrie.

I stand corrected, Mr. Barrie. There is -- there are a few more questions I just want to follow up.

Are you a professional geologist, sir, with APEGA?

A I am a P.Geo scientist with APEGA.

Q P.Geo

A Yeah.

Q Okay. Thank you.

The question is: As a geologist would you agree that picking well tops on wireline logs is a fundamental task expected of a geologist?

A Yes.

Q And would you also agree that the construction of geological cross-sections of wireline well logs to show structural and stratographic relationships of geological formations at and in between existing well control is also a fundamental task expected of a geologist?

A Yes.

Q Would you agree that making maps from the tops picked from wireline wire logs is a fundamental task expected of a geologist?

A Yes.

Q Would you agree that structural maps are important to determining the amount of differential compaction within or above a geological sequence?

A Yes.

Q Thank you.

Last question: Would you agree, then, that ISH has not done any of its own fundamental mapping work to demonstrate that the amount of differential compaction at KN08 and 09 is significant?

A Can you repeat the question, please?

Q I'm going to back up because I think that one is a little unfair without more context. But have you made any structural maps showing the magnitude of differential compaction at KN08 and 09?

A No, I have not had the time. I've relied on CNRL's maps, primarily their depth conversion structure maps on the top of the Wabiskaw B.

Q And just back to your mapping -- and I'm not sure I fully appreciate the differences, but would you call your blue polygon -- has it been constructed based on the proper or the best practice of geological mapping?

A Yes.

Q How did you come up with your map, then, sir?

A Well, I looked at all of the well logs in the immediate area of the blue polygon. I looked at several of the cores that were available to me at the AER. I looked at all of the core photos that were provided to me by CNRL, and then I contoured it using standard geological contouring practices.

Q Last question -- and this is back to the differential

compaction, but would you agree that ISH has not done any of its own fundamental mapping work to demonstrate that the amount of differential compaction at KN08 and 09 is significant as been asserted in your report?

A That's correct. We've relied on CNRL's mapping, as I mentioned a few minutes ago.

Q Thank you very much.

All right. Thank you. I'm just going to -- if you'll give me a moment, we're going to shift gears here.

Ms. Lagisquet -- am I saying your name correctly?

A A. LAGISQUET: Lagisquet.

Q Lagisquet. Oh, my God. It's so beautiful when you say it, but ...

Okay. So I understand -- or can you just confirm for the record that you put together the report filed at Tab 7, Exhibit 32.11?

A That's correct.

Q Right. And I guess we can tell from your résumé as well as your comments yesterday that you've done a fair bit of -- you've got a fair bit of experience with risk assessment, and I think there's some common general principles that we could agree to, and I'm just wondering if we could test those, just what's involved in -- when you're doing it.

So would you agree with me that the initial step

would be to identify the hazards or the potential risks?

A Yeah, that's correct.

Q And then you would identify the barriers or the mitigation, things that would prevent -- maybe it's not mitigation, but barriers, things that would prevent the identified consequence from that risk?

A Yes. You identify an event, you try to identify what causes the event, and you also identify what would be the consequence of that event.

Q And anything that acts to prevent the consequence, would you characterize as a barrier?

A Can you rephrase? I'm sorry. I don't think I understand the question.

Q Yeah. So I'm just -- it's really basic, but we've identified hazards. You talked about the consequence, right, but anything that would prevent that might be a barrier in between?

A Any mitigation that you identify may allow you to reduce the likelihood associated with a risk. A mitigation doesn't reduce the consequence hardly ever. So yesterday I was a bit confused between my right and my left. I'm sorry. I should have said that you mitigate from right to left; right?

Q Yeah.

A But only the likelihood changes, not the -- the

consequence.
Q Understood. I was actually thinking more in terms of barriers, things that prevent. So you had done -- identify a risk, but there may be a barrier before it happens. I have would have said mitigation --
A The control.
Q -- the control, sure.
A Okay.
Q Let's use that. Okay.
So then if we could, please, in your report -- no. It's not your report.
J. JAMIESON: Exhibit 44.10, PDF page 15, please. This is in ISH's IR responses. And I believe if you could scale up on the regional scale on the right-hand side, please. Just zoom it out a little bit so that we get it in front.
Q J. JAMIESON: I believe you spoke to this figure yesterday; is that correct?
A Yes.
Q And if you look to the figure on the right, we could describe the hazard as being steam at the bottom of the reservoir; correct?
A Yeah. I plotted a steam chamber at -- at the bottom to illustrate, you know, the -- the location of the steam chamber.
Q But we can agree the hazard -- the potential hazard is

the steam?
A The steam and the consequence associated with steaming operations, which are gas exsolved out of bitumen as well as potential other reaction product, like when aquathermolysis happens, you know, the release of H2S.
Q Sure. Understood. But the consequence would be the steam invading the Wabiskaw B; correct, or ...
A ISH looks at it from a broader perspective. We are looking at the impact of steam as well as the consequences associated with steaming operations.
Q Okay. How could we describe the -- even if -- even if we were to accept this sort of torturous path that you've depicted in purple there, can we describe -- or would you concur that those different formations potentially act as barriers or, in your terms, control? So there's some controls there, some barriers between the potential risk or threat and the consequence; correct?
A Provided those barriers are present, I would say yes. I think the question here is whether or not those barriers are present at the regional scale.
Q Understood. But we can agree that your evidence isn't that they're completely gone; right? There are some potential barriers or potential, in your words, "controls", between the potential hazard -- this is really fundamental stuff, so I'm not trying to confuse

you -- the hazard and the consequence up in the Wab B pool?

A I mean, if the question is, is it likely that steam would condense before it goes to the Wab B, there could be. And I don't know if I understand your question, so you may have to dummy it down even more for me.

Q That's fair. We're going to move on. It was just the application of some really basic principles, but we will move on.

In this figure, which is -- I understand that to be ISH's concept of risk -- there are six different barriers or discontinues that those are 2 to 6 metres apart vertically, and laterally they are anywhere from about 100 metres apart to 500 metres. So would you agree on that scale? Are you familiar enough with the -- the data filed on the record?

A Yes.

Q Thank you.

And would you agree that in order for a steam to rise up, you know, even a couple of metres and then progress laterally for hundreds of metres, potentially, that could take a very long time since gravity is a much weaker driving force and the bitumen will drain very slowly with the shallow drainage angle; you'd agree?

A Yeah.

Q Thank you.

And would you agree that by analogy the risk may only arise if the discontinuities or the, you know, gaps or whatever we want to call it -- but potential pathways in these six barriers all align very closely to create a much less torturous path than shown here?

A Yeah. Generally speaking, yes. Again, what I would like to clarify -- and it might be, you know, a slight reframing -- is we are looking at discontinuities when -- you know, on the -- in a different perspective, you're looking at the presence of barriers, right. So that's what we have to put in perspective, and that's the whole questions that we've been asking --

Q Understood. Understood.

A -- over the last few days.

Q And I know we're using different words or language. I'm trying to get on the same page with you.

A Yeah.

Q But we agree that you -- you need a pathway in order for the hazard to create the consequence --

A Correct.

Q -- that you've identified?

Okay. Let's leave it there.

Table 50.00 -- sorry -- Exhibit 50.002, and that's PDF page 43, Table 4, and this is a summary of the gas pool values as provided by -- well, the first column

was provided by ISH, correct, in Table 4 in terms of the value of the gas?

A Right.

Q And you used those values, did you, in your risk assessment process?

A Yes.

Q Thank you.

Can you confirm that the -- sorry -- that the numbers reflect -- in that table reflect the values for the gas pools and it actually represents the value -- the total value of two different gas caps, not just ISH's ownership interest, which is 46.25 percent in both? I'm going to break that down. So those numbers reflect --

A It's a hundred percent.

Q -- two gas pools. Two gas pools a hundred percent?

A Correct.

Q What are those two gas pools?

A The shut-in Kirby Upper Mannville II and Wabiskaw A.

Q Wabiskaw A. Thank you.

Again, Column 1, the one that ISH produced, that assumes the gas production starts as of January 1st, 2024; correct?

A Correct.

Q And the risk that you identify, of course, assumes there's leakage of steam from the McMurray into the

Wabiskaw, the pathway that we identified earlier? That's a basic assumption that you're making to get to that consequence?

A I believe that I mentioned reaction products in my risk assessment.

Q And by that you mean the dynamic of aquathermolysis?

A Not only. I mean, gas will be exsolved as a result of SAGD operations.

Q Do you agree for the purposes of the risk assessment that some discounted value of the gas should be used?

A No.

Q No. But you are --

A Let --

Q -- acknowledging you used a hundred percent of the gas from two gas pools?

A Let me confer with my colleague.

Do you mind repeating the question, please?

Q Yeah. Well, I asked you first: Do you agree that for the purposes of the risk assessment that some discounted value of the gas should be used; you said no?

A No.

Q And then I asked you: Would you agree that 20 years is a reasonable estimated life expectancy for the SAGD drain -- drainage boxes?

A Yeah, that's correct.

Q Yes. Okay. So 20 years you feel is reasonable, but your clear answer on discounting was no, and why would that be?

A Let me validate with my colleague.

What ISH provided here is the value of the gas reserves, and we don't believe that we need to discount the value of the gas reserves.

Q Thank you.

Let's just do some --

A J. CHODZICKI: I could elaborate on that.

Q Go ahead.

A So the discount -- any time you have a cash-flow stream, you pick a discount rate. The discount rate assumed for the cash-flow stream of a declining gas reserve volume is 10 percent. The effective date is the 24th of January. If you push it into the future, you always get a lower NPV. We're looking at what could we do if we were to start this production up right away? That then says, This is what we think the value is.

Now, CNRL also stated yesterday that the life of a SAGD pad is between 10 to 20 years, and there is uncertainty in the life of a SAGD pad. As a result, we look at the gas that's just what is it worth to us at this current time.

Q Thank you very much. We actually have some follow-up

questions to that, Mr. Chodzicki, so we'll come back to that. Thank you.

I just want to complete on your risk assessment work, Ms. Lagisquet. And these two next questions are really just from a logic perspective, really. Would you agree that it would be more appropriate to at least reflect numbers that reflected the 46.25 percent of ISH's in the pool as opposed to the 100 percent?

A A. LAGISQUET: Well, if the pool is contaminated, I can't guarantee that you're only going to contaminate the one-half that CNRL doesn't own; right? So the pool is contaminated or is not contaminated; right? So applying the working interest to this evaluation I don't think makes a lot of sense. It's -- it's more binary question is that: Is it contaminated, or is it not contaminated? Do you have controls, or do you not?

Q Understood. But the only -- you would -- you would have to concur with me that the only piece that's relevant would be the damage to ISH's interest in the pool; correct? You're not looking out for Canadian Natural's gas interest?

A But -- but, again, if it's contaminated for ISH, it's contaminated for CNRL.

Q Yes. Understood. But I would've thought your risk assessment -- the scope of it would've been focused on

ISH's interest. Are you saying that's not the case? The scope of your report focused just on the gas pool, and you didn't divide it -- you didn't -- these numbers don't reflect the value of ISH's gas. That's the confusion?

A Correct. It's a hundred percent as it's said in the -- in the title.

Q Thank you.

J. JAMIESON: If we could bring up Exhibit 32.02, Figure 21.

A I would say before we move on -- on from that, if we agree that the value as of January 1st, 2024, even applying the working interest would be over a million dollars, right, and when you go back to the risk assessment and you look at the consequence, the financial consequence, the range is 100K to a million and then a million to 10 million. So even if I apply the working interest, it doesn't change the inherent risk.

Q Understood. Thank you. That's helpful.

J. JAMIESON: All right. Please, Ms. Arruda, it's Exhibit 32.02, PDF page 39, and Figure 21. And if you could just -- yeah. That's great. We can just read that title.

Q J. JAMIESON: So, Ms. Arruda [sic], are you familiar with this map? It's the Wabiskaw B net gas

pay map. It was prepared by Canadian Natural, but the purpose of it was to show the two pools.

A A. LAGISQUET: Yeah, I -- I recognize -- I recognize the map.

Q Okay. And so, you know, I think there's been a little bit of talk of possible communication between the pools, but the question really is if you had some contamination, you know, to the far west in one of the pools, you know, is it reasonable to assume contamination at a hundred percent of the other gas pool?

A J. CHODZICKI: Yeah. I can discuss that part. The -- obviously contamination would occur over a period of time. The concentrations of CO2 and H2S in the McMurray SAGD projects, if they are to leak into the Wabiskaw B, could be a -- a problem -- a big problem. However, the spread of that would have to be determined with future modelling. And the fact that there is some risk that the pool Wabiskaw B zone could be contaminated implies that there has to be a degree of caution because the other issue is with safety of the wellheads. If you have H2S in a pool and you're set up to be a sweet producer, if there's any kind of leaks, you'd have a safety risk on surface. So that is an additional risk in addition to the contamination of this gas. The exact time at which the gas will

contaminate is difficult to determine for sure.
Q Understood. And thank you very much.
And just back to Ms. Lagisquet. If you were to only evaluate the consequence in terms of the one pool, the Kirby Upper Mannville II, what does that do to your risk assessment? So your consequence is -- is -- excludes the other pool.
A A. LAGISQUET: Yeah. As I mentioned earlier when you showed me Table 4 of the other exhibit, if we agree that the value as of January 1st of 2024, I think, for the Kirby Upper Mannville II was in the order of 3.8 million. Even if you apply the working interest, you're still above a million. So it doesn't change my risk assessment.
Q I'm asking you to do both at this point. I'm asking you to focus on ISH's interest in one pool, the Kirby Upper Mannville --
A Yeah.
Q -- II --
A That's -- that's what I --
Q -- does that -- okay. But -- well, I can't do that math. But does that not -- does that get us under the million dollars?
A No, it doesn't.
Q It doesn't. Okay. Thank you.
At the very end of your executive summary -- so

this is Exhibit 32.11, PDF page 4, and it's lines 84 and 85. Yeah.

So I'll just read these out just because I can -- it might be hard to read. You state: (as read)

> The author acknowledges that the cost of incremental monitoring should be commensurate with the risk and that additional information may be required to analyze and evaluate the risks to ISH's gas assets.

In your assessment, you're stating that all the risks are financial only; they're not safety or environmental risks. So given that qualification, if the consequence of a risk is financial only and the specific risk has a 10 percent chance of occurring, how much is it reasonable to spend to mitigate that risk?

A Again, a risk assessment is -- is a dynamic process; right? And I appreciate the asymmetry in data between ISH and CNRL for us to be able to evaluate the risk.

So, again, this is a time 'T' assessment provided. More information is available, it could change the risk profile; right? And that's the whole point of a risk assessment; right? It's to -- it's to measure our ability to either prevent or reduce the -- the risk to an acceptable level.

Q Understood. Thank you.

A Right? And I framed my assessment based on the

information that I had.

Q Understood. Yeah. I'm just asking you to revisit your evaluation given this additional information, given the information I'm putting to you. But we can move on.

Exhibit 32.11, please, and this is PDF page 33, Figure 19.

And we'd just like to better understand your case for Risk 2. If -- could we zoom out just so you could perhaps -- if you could identify your wording for Risk 2, please.

A Yeah. So I'm saying: (as read)

> Due to the close stratigraphic proximity of the Wabiskaw D to McMurray formation and the presence of discontinuities in the confinement strata intervals in areas of KN09, there is a risk of subsurface steam loss of confinement within the McMurray formation during SAGD start-up resulting in loss of economic value for the ISH due to the contamination of the GOB shut-in gas pool as a result of reaction products, mobilization in the formations below.

I put a likelihood of 4, which this could happen once in ten years.

Q Once in ten years. Thank you.

A Yeah. And a consequence between a million and

10 million, assuming the entire pool is no longer producible.

I'm also qualifying at the bottom of the table that as Dr. Boone, you know, identified, I don't think the -- the risk is necessarily at the time of start-up, but I'm trying to frame the potential long-term consequence of the start-up that could create those additional pathways for reaction products to move from the McMurray to the Wabiskaw B formation.

Q Understood.

And just -- I just want to clarify. You just stated "the entire pool", but for Risk Number 2, you actually were identifying consequence to both pools; correct?

A It wouldn't have changed the inherent risk. So, again, it's a matter of how we value the shut-in gas assets.

Q Understood. Thank you.

Exhibit 50.002, please. And this is PDF page 5. And this is under d. There's two sub-bullets here, and I just wanted to confirm your familiarity with the temporary MOP of 6,600 kPa -- you're aware of that -- in that Canadian Natural's commitment to that is a maximum continuous time of 24 hours?

A Yeah, I see that in the second bullet point.

Q Okay.

A First. Sorry.

Q Excuse me one moment, please.
Ms. Lagisquet --
A Lagisquet.
Q Lagisquet. Sorry.
Okay. So Dr. Boone, in his direct evidence, presented evidence that the mudstones in the confining strata are ductile and not brittle, the way that Dr. Chalaturnyk asserted. So if we follow Dr. Boone's analysis, any induced fractures are very likely to be sealed after they are -- after they close. So in -- just -- I just want to cover off this short-term risk. So if we just have a short period of steam injection at high pressure, is that a fraction of the condensed steam that flows into the Wabiskaw B gas zone such that it would -- such that the impairment of the entire value of the gas cap would be highly unlikely?
A I would answer that, generally speaking -- and I don't have Dr. Chalaturnyk with me --
Q Yeah.
A -- today to kind of validate the behaviour, and I think there's still disagreement on the ductile versus brittle behaviour, so my answer is completely hypothetical, but I understand what you're saying in, you know, it could minimize the risk, like the near-term risk, right? I'm still talking -- and that's the challenge. We're still talking about different

things where I focus on the full life cycle when I analyze the risk versus, you know, a time zero to a hundred days of start-up. So I'm looking at the long-term consequences of a start-up going wrong and being undetected.

Q And being what? Sorry.

A Undetected.

Q Undetected.

So the start-up going wrong being undetected and some potential long-term consequence from that. Okay. Thank you?

A Correct.

Q All right. Thank you very much for those responses.

I think we have one more line. If you can just give us a moment, please. Okay. Thank you.

So Mr. -- let me make sure I get your name right. I will do my best, Chodzicki?

A J. CHODZICKI: Yes.

Q Thank you very much.

Okay. So we do have one last line, and I think you are the right witness. It sounds like you're the one that might know.

J. JAMIESON: If we could turn up, please -- this is a response. It's an IR response, so it's Exhibit 44.002, and it's pages 62 and 63.

A Okay.

Q J. JAMIESON: We'll just wait till it gets up on the screen.

J. JAMIESON: If you could just expand it a little bit. I think -- I'm looking for paragraph 62 and 63. Does that show up on there? Oh, page 62, 63. Sorry.

Q J. JAMIESON: This is where Canadian Natural asked a number of questions about the gas -- the value of the gas pool. So I don't think we have to refer to anything specific, but just generally. So a moment ago, Mr. Chodzicki, I thought I heard you confirm that you value the gas on a reserve basis?

A Yes.

Q And do you currently assign proven or probable reserves to the Kirby Upper Mannville II pool?

A Again, as a private company, we do our own internal evaluation that we would call this proven developed non-producing.

Q Sorry. Proven, not developed --

A Proven developed not producing.

Q "Proven developed not producing." Okay. Thank you.

And just -- we're just focused on the Kirby Upper Mannville II pool, so if you could just confirm that value? I believe it's in -- I don't know if -- on page 63 should be your response there.

A Yeah. That paragraph there, that -- so the total was

5.7 million and Upper Mannville II pool was valued at 3.685 million, and so that -- that 3,685,000 is the value that would have been allocated to the Kirby Upper Mannville II pool.

Q Thank you.

And is this a discounted value?

A That would be discounted at 10 percent.

Q Do you --

A 10 percent discount rate.

Q Right. But you confirm that the Kirby Upper Mannville 2 pool or II pool is shut in due to the GOB decision?

A Yes, it is.

Q In the reserves evaluation, in which year are the Kirby Upper Mannville II wells returned to the production -- returned to production?

A Well, this was a calculation done to show that, What do we think the value is if we were to start this pool up tomorrow?

Q And why -- can you just help us understand why, in your view, "tomorrow" is a reasonable presumption, given that -- that it's clearly shut in?

A Well, let me confer.

So our opinion was that -- and, you know, we've shown there's very minimal capital outlay to reactivate this pool, and we could turn it on at any time if we had the permission to. So it doesn't matter. The

value still exists; it's just a matter of when we would reactivate the pool, but there is still a value to the gas reserves in the pool.

Q And when would you expect to receive that permission?

A That, again, would be subject to regulatory, but we haven't gone down that path, but, still, for the purposes of this evaluation to show that there's a risk to the value of the gas reserves, we say that the value when we choose to reactivate it would be this, then discounted into the future at 10 percent discount.

Q Mr. Chodzicki, yesterday ISH's legal counsel, Mr. McLeod, he was asking Ms. Lagisquet a set of questions about what she thought the 2.5 million of incremental costs potentially from the mitigation added to the KN08, 09 project was minimal, and in the end he characterized it as "just a drop in the bucket", which she agreed to. Do you recall that exchange?

A I think I do, yes.

Q And I believe she was making that comparison in relation to the total development costs of the project. So how would you compare 2.5 million to the value of the reserves of the Kirby Upper Mannville II pool?

A Oh, I think the discussion yesterday was that considering the total value of a SAGD project, of which this monitoring would still give information about caprock movement and -- and things like that, that

could still benefit the long-term understanding of a SAGD project that some of the costs of this monitoring should not be considered just to be implied, to be forced entirely upon the Kirby Upper Mannville II pool, that there is a need for monitoring in SAGD projects. I think that's where we were going with that yesterday.

Q Understood. But is it -- is it ISH's position that that -- the gas pool should be -- or that mitigations at all cost -- at any cost should be put in place to preserve the gas pool?

A A. LAGISQUET: I think, again, it's about preserving ISH's ability to produce that gas in the future, whenever they are authorized to reopen that gas pool; right?

Q At any -- this -- my line of questions, in fairness, has to do with cost-benefit analysis. So I'm taking it to an extreme to make a point. At any cost, is that ISH's view?

A Well, if we -- if we want to take it to an extreme, I think, you know, given the pressure that we have currently in our industry to identify, you know, low capital, low GHG projects, I think it's in everybody's best interest to ensure that these gas pools are preserved for the long-term, you know, affordability of energy for Albertans.

Q I'll just confer and see if there are any final

questions.

I believe those are all our questions. Thank you very much, ISH panel.

J. JAMIESON: And thank you, Commissioners. We are complete on that, you'll be glad to know.

COMMISSIONER CHIASSON: Thank you, Ms. Jamieson.

We'll take our morning break now. There will be questions from the AER for the witness panel, so just the reminder not to confer over the break. And so we will be back at 10:30.

W. MCCLARY: Commissioner Chiasson, if we could maybe just extend that to 20 minutes for a break or -- or perhaps a bit more just to allow for a proper break and a little bit of conference on our end.

COMMISSIONER CHIASSON: Okay. Let's -- okay. Let's come back at 10:40, then.

W. MCCLARY: Thank you.

COMMISSIONER CHIASSON: So that gives us 25 minutes. Thank you, all.

(ADJOURNMENT)

COMMISSIONER CHIASSON: All right. Thank you, everyone. We will proceed with questions from the AER, and I believe Mr. McClary is starting off.

W. MCCLARY: Thank you, Commissioner, Chiasson.

The Alberta Energy Regulator Legal Counsel Questions

the ISH Energy Ltd. Witness Panel

Q W. MCCLARY: Now, when I'm asking these questions to the witness panel, please feel free to confer as you see fit based on the question presented, and just let me know probably who's best suited to respond as we go through.

Again, Will McClary here, legal counsel for the Alberta Energy Regulator. Got a few questions which are intended to help us clarify some of the evidence that we've seen and to provide context if necessary for decision-making purposes, et cetera.

The first one is really a true clarification question, and it came up in the evidence presented just before the break here. There was discussion of a value of the reserves of -- I believe it was $3.685 million. And when we're looking at that, the question is just whether that's the -- the whole value of the reserves or if it's an assessment of the working interest. So should that value, you know, be multiplied by some percentage, or is it, you know, ISH's working interest that's been presented there?

A J. CHODZICKI: I'll take that question. You're correct. That is the hundred percent value of what we see. And the logic behind that at the time was we saw it that ISH was acting as the operator on behalf of our working interest partner in that Upper Mannville

II pool. And the number you referred to is the amount we would prorate back to the Upper Mannville II pool as a result of a -- like, a production kind of rate forecast we gave for what those wells could produce.

Q Great. And it sounds like you want to provide context on that number. Is there any further context you want to provide with respect to those numbers?

A There is this one table that we submitted in our IRs. Let me take a look. It -- so IRs back to CNRL would have been the 44.002 exhibit, I believe. I think that's ...

Q Are you looking at -- is it PDF page 62? Is that what we're looking for?

A I think that's where I'm headed to. Right. That's -- that's the one. Correct. Thanks.

So what was done, we basically looked at the rate at the time of shut-in, and then we looked at the pressure change to what it is currently. We gave a projected rate. We then said, Based on these pools potentially being in communication, although not verified, if we had a certain volume of gas determined by material balance, how would we prorate the proportionate amounts of gas reserves back to each of those pools? So that would've been these rates, total volumes declined out, given an NPV -- net -- net present value forecast discount at 10 percent. That's

how it would have been obtained.

Q Great. Thanks.

Now, moving on to some geochemistry. So we heard yesterday -- and I believe the quote was along the lines of the -- that Dr. Fowler could not comment on the lateral extent that could be interpreted from the data. And if I could please pull up Exhibit 43.002 at page 234.

And this is from Fustic 2013, for context, which I see Dr. Fowler nodding along. We noticed that you're recognized in the acknowledgments of both Fustic 2011 and 2013 so should be familiar with this, but if we could get that exhibit up, please. Thank you.

And the quote that I'm looking at starts with: (as read)

Anomalies in well vertical compositional gradients.

It's under the heading "Implications for Reservoir Development". I think it's up on the top of the right-hand column. Oh. Yeah. There. So if we could zoom in, it's the -- the first new paragraph on the right side. Yeah. (as read)

Anomalies in well vertical compositional gradients may be used for distinguishing between barriers and baffles. For example, subtle deviations in the compositional

gradients evident in Samples 5 and 6 in Well 6, Figures 23 and 24, indicate a baffle that slows but does not stop the mixing of fluids inferring that steam advances will behave the same way.

And then this is the part that I'm -- I'm interested in, Dr. Fowler. It says: (as read)

Greatly changed compositions between Samples 8 and 10, for example, in Well 6 suggest that no communication existed between the two reservoir units inferring that the mudstone between them is laterally extensive, thus geochemical data from the integrated baseline studies can be used as a powerful tool for distinguishing between barriers and baffles.

And it's cited to Bennett et al and Fustic et al 2011.

So I think you can understand that there's a bit of tension between those two statements, but I'm confident that you'll be able to provide an explanation as to how we can contextualize those two statements.

A M. FOWLER: Okay. As Mr. Barland said, the data we see is from one well. We -- you know, you assume that there is some lateral extent, but it's the lateral extent of that particular reservoir compartment. How big that reservoir compartment is

laterally, you know, I don't think the geochemistry can tell you. It's -- you know, if you looked from a conventional reservoir as -- which people have done reservoir compartmentalization studies way before they came into heavy oil -- they can be quite small when we've gone back and looked, or they can be quite extensive. But you can't tell that obviously from the geochemistry data unless you have geochemistry data from two different wells where you can compare and say these two well -- these wells are in communication.

Q And I think, if I understood your evidence correctly, that because different -- different strata I think had been identified in relation to the barriers and baffles, then the lateral extent that could -- the extent of whatever lateral extent could be inferred from the GCMS data, you would hope to see that kind of confirmed in other wells in the same zones? Is that a correct understanding of what --

A Can you --

Q -- what your position was?

A -- just clarify the question a little bit? Sorry.

Q So I -- I guess the evidence that I believe you put before us yesterday was along the lines of while you observed different reservoir compartments and a strong barrier in each of the six wells for which geomechemical data was provided, which I think it

should say geochemical data was provided, similar to what Mr. Barland stated on Tuesday -- and this is you speaking: (as read)

> I cannot comment on the lateral extent. As different intervals are providing a barrier in different wells, this suggests that individual barriers are not laterally continuous over the whole area of the proposed development, that whatever this means, there are possible gaps between the different barriers that would enable steam reaction products to escape into shallower areas.

Now, considering what Fustic has said about the 2011 paper and how the geochemical data can suggest lateral extent of a baffle or a barrier, is there tension between those two statements? Is there -- can we infer a lateral extent based on geochemical data, or is there a limit to the lateral extent that can be inferred and ideally -- I know that you'll probably hate this question -- but ideally with units and distances?

A I -- I don't think I would give -- I could give you a lateral extent of a barrier. It's -- it's -- you know, we look at the geochemistry data. We're not looking at the whole geological context.

Q So then does that suggest, then, disagreement with the

conclusion in Fustic 2013, that there -- that you can use the geochemical data to --

A I -- no. I mean, it works. But I think, as Mr. Barland said on Tuesday or Wednesday, the Fustic papers were early papers, and they were looking purely within the reservoir. They weren't looking for kind of -- you know, within compartments. So you're, like, separating out, like, within the McMurray and you got clear reservoir compartments because those -- those Fustic et al. papers were an extension of what we used to do in -- before for our conventional reservoirs.

In the last 10 years, 12 years, we have a lot more experience on the heavy oil reservoirs, and there's not been many papers published, peer review. It's -- it's like giving short courses. You're always stuck because you can't cite anything. But the one thing we do know, there's a lot of variation.

Q Thanks.

Now, is there anything in the GCMS data that you reviewed to suggest that there is an absence of confining strata over the project area?

A There's a barrier in each of the wells, a strong barrier.

Q So I'll take that, then, as a "no" to that question. So there's nothing you found that would suggest that the confining strata don't act to confine as CNRL has

suggested they would?
A Can you just --
A A. LAGISQUET: Can I maybe add a little bit to that, please?
Q Certainly. I guess the question that I posed to Mr. Barland earlier was whether GCMS data could be used to interpret the absence of a barrier or a baffle, and I believe his response to that question was along the lines of, yes, it can. Do you agree or disagree with that assessment?
A M. FOWLER: I would agree with that.
Q So was there anything in the data you reviewed that would suggest there is an absence of confining strata between the two relevant zones here?
A On a point basis, there's -- there was a -- there's confinement --
Q Thanks.
A -- I would say, strata in each well.
Q Thank you.
And, Ms. Lagisquet, if you want to add to that, feel free.
A A. LAGISQUET: Yeah. We're looking at data from a core, right, so roughly the size of my cup here, and trying to extrapolate what that means on hundreds of metres. And what we've heard is that GCMS data is not able to do that; right? It can tell you if it sees

a barrier at the core level, but hundreds of metres away from that, it can't tell if the barrier is still going to be there. The way you constrain it is based on operational data. You know, once your steam chamber is starting to develop, can you tell, you know -- backcast in a sense -- and say whether or not GCMS data was predictive?

A M. FOWLER: I mean, just the barrier will be that lateral container reservoir compartment. You know, you can have vertical reservoir compartments, but there's also -- obviously it's 3D. You -- you -- you -- it's going to have -- that reservoir compartment is going to have some lateral continuity where the GCMS data will be valid for. How far that -- how big that -- the reservoir compartment is laterally I cannot tell you from a geochemical data. You need the geology or whatever to do that.

Q Thanks. I think that -- that assists because I think the issue that we had was trying to square the statement in Fustic 2013 about it being useful for lateral extent. But it sounds like your evidence there would be that the usefulness of the lateral extent is not quantifiable and, you know, hasn't been further investigated since 2013.

A Yeah. I mean, as I said, that was -- it was fully unconventional. In the old days, in conventional

reservoirs, you would be looking for the lateral continuity rather than the vertical continuity a little bit more, in conventional reservoirs. And there you would have more wells, or you would kind of define that -- that compartment. Here, you know, if -- where we -- you know, where you see differences, then, yeah, might suggest it's a different compartment.

Q Thanks. I think we've got enough there.

If we could please move on and pull up Exhibit 32.02, PDF page 12, Figure 2.

And, Mr. Barrie, I'll be, I think, directing this generally towards you, but if anyone else wants to pop in, please feel free.

So in the direct evidence, I believe we heard from you that the vertical permeability of the Wabiskaw C is quite high due to the presence of vertically oriented sand-filled burrows; is that correct?

A That is correct.

Q And then I believe reference was made to this photograph that we've got up, and maybe if we could please zoom in a little bit on the log in the middle of the page at Figure 2 titled "Wabiskaw C Top". And you referred to this image; right?

A That's correct.

Q So your conclusion with respect to vertical permeability in the Wabiskaw C, was that -- is that

based on your opinion and an interpretation, or was there any effort made to obtain vertical permeability measurements using means available like laboratory samples, et cetera?

A B. BARRIE: We did not connect -- conduct any laboratory testing on this rock. I would say my opinion is based on two things: One, my verbal -- or my visual examination of the core and, secondly, the fact that CNRL did not use this unit as a confining strata in their application for KN06.

Q Is there anywhere in the materials, I guess -- like, in the materials filed for this proceeding that you could point to in support of your conclusion with respect to the vertical permeability?

A Could you repeat the question, please.

Q So I guess for the purpose of a hearing, typically a panel is confined to the evidence that's before it, so is there anywhere in the evidence before us that you could point to as evidence in support of your assessment of the vertical permeability of the Wabiskaw C?

A Yes.

Q Can you take us there, please?

A Yes. I would like to point to the visual evidence in this photograph, which shows very well-developed vertical burrows possessing oil-stained sand with very

high porosity and permeability, and this rock generally has a very high percentage of porous permeable sand in it.

Q Thanks.

Now, in light of that, is that -- is that -- is there anything else you would take us to in terms of the materials that we have?

A No.

Q Thanks.

In light of that assessment, we'd like it if you could comment a little further on the nature of the permeability pathways that you've just identified, you know, connection, extent, composition, what they're filled with, et cetera.

A Okay. I thought I just did that. The permeable pathways are indicated by the burrows here and interconnected pores between the sand grains that are visible in this photograph. I would like to add that it is my strong opinion that this rock has been intentionally fractured by a process called "differential compaction", which creates vertical permeability pathways within the rock that are not shown in this photograph.

Q Are you able to speak to any analogous geologies with respect to vertical permeability created by these types of burrows?

A No, not within the context of a one-minute answer. I would need to take you and show you some core and some analyses and so on. So for the purpose of this answer, we only have this photograph.

Q Then in -- in conducting your analysis of this core, did you seek out any analogous geology to -- to justify your conclusion about the vertical permeability of the Wabiskaw C?

A I relied on my 42 years' experience as a geologist working in this basin and having looked at thousands and thousands of core here and throughout North America that assisted my opinion.

Q Thanks.

I think I'd like to move on, unless there's more?

A Oh, I -- I could add to that.

Q Yeah.

A Okay. If we look at Exhibit 50.003. You want to go to page 41 and 42. Down near the bottom we see the last paragraph: (as read)

The SSG does not believe that the Wabiskaw C interval acts as a regional seal in the area.

On the next page -- this is from the original -- the study was back in two thousand and -- 2005. On the next page, page 42, it's mentioned the Wabiskaw -- (as read)

Based on the inconsistent -- inconsistent

cementation of the Wabiskaw C interval and the potential for it to be absent, the Wabiskaw C interval cannot be relied upon as a regional seal.

That was part of the original justification to say that for the shut-in of the -- the gas over bitumen shut-in at the time. So that -- I mean, that's some of the -- there's a comment there on the 1-11 well. You see a bullet point there: (as read)

Highly bioturbated and bitumen-stained but not cemented.

So very variable geology here, and ...

Q Thanks.

Now, again, to whoever on the panel, but Mr. Barrie generally, is there any evidence before us to suggest that these vertical burrows that are identified in that core photograph that we were looking at earlier extend throughout the Wabiskaw C interval or are present elsewhere, have been observed elsewhere?

A Yes.

Q Can you take us to that?

A It would take us some time for me to go through each of the core photos that I've looked at that were provided by CNRL, but, generally speaking, without -- throughout the Wabiskaw C sand interval, it looks like that photograph I just showed you. So it's present

everywhere.

A. LAGISQUET: Can I maybe add something --

Q. W. MCCLARY: Certainly.

A -- because the page is already there.

So if you look at the fourth bullet point: (as read)

> Photos of cored wells to the south of the Upper Mannville II pool show that where the Wabiskaw C interval is thicker, it consists of highly bioturbated and bitumen-stained sands and muds.

So I think that would be valid at the regional level because this was a regional study.

Q Thanks.

Now, in relation to the -- the vertical -- what are we calling them again? The vertical ...

A B. BARRIE: Burrows.

Q Burrows. Thank you.

They're filled with sand; right? That's my understanding of the evidence.

A Yes.

Q Thanks.

Where does that sand originate from?

A Well, the sand would have been deposited by some process on the sea floor, storms, dunes migrating around on the sea floor, and at some point, organisms

were allowed to churn through the rock and redistribute the sand so that you can't observe original -- or primary sedimentary structures that may have once been there.

Some of these sand bodies could have been deposited fairly rapidly, essentially burrowing -- burying the organism, and some of these structures we see are so-called "escape structures" where an organism was buried and escaped through the sand overlying it and left the traces that we see in the photograph that we just looked at.

Q Thanks.

Can you explain to me what is meant by the term "torturous"?

A I would like to confer on that, please.

Q Thanks. Go ahead.

A Could you please clarify the context of the question.

Q In respect of the log that we were observing earlier --

A Do you mean core photograph?

Q The core -- yeah. Sorry. The core photograph. Would it be fair to describe -- or would it -- is there any evidence to suggest that a network of those burrows would be or would not be torturous or torturously connected? Like, is there any evidence in our record that would allow us to create an assessment about those burrows and whether they're torturously connected?

A I don't have any data on that.
Q So would that be to say that there's no data to suggest in either direction whether a network formed by those burrows and pathways between them would be torturous or would not be torturous?
A There is no data available.
Q Okay. Thanks.

Now, the next set of questions is going to relate to stratigraphic context of the fractures, et cetera, identified in the HEF logs, so just a heads-up -- and, Mr. Vickerman, feel free to confer if necessary. Are you able to explain your process for how you go about determining whether a fracture that's observed in a borehole image log is open -- or an open hole -- or an open fracture, rather, is naturally occurring or drilling-induced?

A K. VICKERMAN: Yes. The drilling-induced fractures have a particular geometry in the borehole. They tend to reflect so that they exist parallel to the borehole, at least for certain parts of it, and that gets really complicated as the deviation increases and then depending on the direction that the hole is drilled in.

So if the hole is drilled, for instance, towards the maximum horizontal stress direction, then any induced fracture would tend to be a vertical sheet

fracture that looks like a vertical line on the -- on the plot.

Whereas if you have some angle -- if you're drilling now across that -- that maximum horizontal stress direction -- and I'm using my hands to -- to have an inclined borehole and a vertically oriented fracture, the fracture would want to come in parallel to that stress direction plane, that vertically oriented stress direction plane, but then as it gets into the borehole would reflect parallel to the borehole for a part of it and then reflect out the top so that the features tend to be nonplanar.

And if you remember the sigmoidal bedding that we talked about yesterday, it would have that sort of shape where it -- where it comes in, it has a curvature, it goes parallel to the borehole, and then reflects out. So that's how they would appear in -- in the image logs that -- that I looked at because they were both deviated. We didn't see that in those logs. They were -- the features that I identified were planar, and they also had either a cusp or a trough to them.

And if -- if you have a feature that now crosses, say, 30, 40 percent of the borehole, it's now away from that maximum horizontal stress direction side of the borehole and now in the opposite side where the induced

fracture wouldn't -- wouldn't exist.

So it has to do with -- there's -- there's a narrow range on the -- on the inside of the cylinder of the borehole that those kinds of features land and -- and to do with their shape.

Q Thank you.

Now, in terms of the analysis, is it -- sorry. Is there some further --

A We're good.

Q Okay. In terms of the analysis you conducted on the -- I believe it was two wells, right, that -- that you looked at the --

A That's right.

Q -- borehole image --

A That's correct.

Q -- logs for?

A Yeah.

Q They were the 9-33 and the 11-34 wells; right?

A Yes.

Q So for the 11-34 well, did you observe any drilling-induced fractures?

A We didn't report any, no. I -- and I should -- I should add the 9-33 was the original name of the well, and I think it was subsequently named to 5-34.

Q Noted.

A Yeah.

Q I think for your purposes when we're looking at the exhibit that it's still titled "9-33", but if --
A Yeah.
Q -- if there's confusion later, I will very much appreciate that clarification.
A That's correct. It's the same well. It's -- we just had the old headers. We -- so I used that in my -- my titling.
Q Thank you.

Now, to confirm, you said for the 11-4 well you conducted the analysis that you just described, and there weren't any drilling-induced fractures?
A There weren't any that we identified.
Q Thanks.
A Yeah.
Q And then is that the same for the 9-33 well, or are there drilling-induced fractures in the 9-33 well?
A If you look in my report, there's a Stereonet for the -- oh, actually, I should --
Q We could pull it up, I think.
A Yeah. Let's -- let's do that.
Q I believe it's Exhibit 32.08, PDF 47 or 23. I'm not sure. Oh, here. And -- sorry -- were you looking for the log or the --
A Okay. So page -- page 20 on the PDF. I say no drilling-induced fracture, so that's for the -- the

first well, which would be the 11-34. The similar diagram in my report from the second well is page number 44.

Q Page 44. Thank you.

A And I -- I guess I misspoke. So the -- we did pick three different drilling-induced fractures in that image log.

Q Now, in terms of -- just to contextualize that. I'm not trying to, like, get you or anything, but as a percentage of the fractures identified, is -- how many is three? Like, what -- what percent of the fractures overall is three fractures?

A So there were 16 open fractures. So, I mean, 3 drilling-induced and 16 open. I should say when I pick a drilling-induced fracture it may be more of a representative pick rather than picking every single feature. So if we see a trend of those sigmoidal borehole parallel things coming through, we might pick at a larger scale. I might look at 5 or 10 metres at a time and do a pick that goes through the borehole parallel part of it because that tells you the strike direction of that -- that maximum horizontal stress direction.

Q Thanks.

Now, speaking more generally about the fractures that were identified, can you indicate -- or can ISH --

and I think that this is probably something that you'll want to get the panel's support on -- the witness panel, I should say. We just want some clarity on the stratigraphic intervals in which the fractures, both healed and open in this case, that HEF identified in both wells occurred.

So maybe the easiest way would be to go, like, well by well just to confirm the stratigraphic intervals in which the fractures, and, again, either healed or open, were identified.

A Yeah. So maybe go to page 46 on this.

Can we scroll down a little bit on this log?

Q Certainly.

A Okay.

Q Maybe a depth would probably be the most helpful for the record and for our assistance.

A Agreed. So if -- if -- if we look down from the top, the -- the -- the dark part of the image that marks the very top of the log down to 503 metres would be the -- the Clearwater. The Wab C, I think, starts at 519 or thereabouts on this log. You might push it a little bit down based on the image of where that contact might be more at 520.

And then the -- just from looking at the image here, you see that there are some shales that are coming in at approximately five -- 560 or so. That

would be the -- probably the base of the non-reservoir McMurray, and so it would be between that 560 and 519.

Q Thanks.

Now, how much confidence do we have in those assessments, and what are they based off of?

A The -- the assessment of the tops?

Q Yeah.

A The picks as you were -- as it were.

A J. CHODZICKI: Oh. We're looking at the Tab 3, Exhibit 43 point -- 043.197, Tab 3, core photos and image log catalogue as provided by CNRL in -- I believe that was in their file submission. I'm not sure if it was an IR reply, but -- so we're -- we're assuming CNRL's -- of -- identification from their spreadsheet from the Tab 3.

Q Thanks.

So just to clarify the process that -- that's being used here -- oh, that's helpful. I didn't even think we could do that -- you're relying on the picks that CNRL has provided for the same well and then applying those to the -- the log that we were just looking at?

A Well, we actually didn't apply it to any log.

Q Or --

A Kris's analysis is completely independent, and -- so now we're just on the fly here taking the spreadsheet

and saying, There's evidence of fracturing in different parts of the confinement strata when we look at the whole intervals from 519 down to 539 or 540 or lower still.

Q One moment. I'm just going to confer.

So if I were to ask you the same question for the other well, the same process would be followed; you'd look at the -- Canadian Natural's provided picks in respect of the -- the formations at issue in this hearing and then confer with Mr. Vickerman's analysis with respect to fractures?

A Yeah. That would -- that would be what we would do. The -- again, we were hoping to get detailed picks earlier in the process ideally with FMIs that would have been applied to us with the different layers so we wouldn't have to muddle through. But first step was Kris analyzes, looks for fractures, and we just say that there's some evidence of fracturing in various layers.

Q Thanks.

And to confirm, then, the -- the evidence remains that the fractures that were observed are found within the confinement strata that are at issue in this hearing?

A Based on looking at the Tab 3, there is some evidence of fracturing in this 9-33 well that we have been

discussing.

Q One moment. I'm just going to confer before moving on to the next subject.

Thanks. That is all I've got, I believe, for the -- the fracture analysis and moving on to the subject of appropriate monitoring conditions under Issue 2 of the hearing.

So if we could pull up, please, Exhibit 32.02, starting at PDF 44. It's paragraph 141 of ISH's submission. And it relates to the monitoring conditions proposed by ISH and its experts. And maybe if we could zoom out a little bit if that's still legible because it carries over to the next page just for context. It's not -- yeah. Does that work? Is that legible across the room? If not, we can just zoom in and ask to scroll up and down if that's better. Just let me know.

So the first question would be that ISH has expressed that a minimum of one well per pad be instrumented for monitoring, and am I correct in understanding that that would be monitoring of pressure and temperature?

A A. LAGISQUET: Yeah. That's correct.

Q Thanks.

And then the following zones are proposed to be monitored by ISH in this paragraph: It's Wabiskaw B

gas, the Clearwater caprock in -- in brackets, the Wabiskaw D and the McMurray formations. Now, before we jump into the next question, can we just clarify what's meant by the "McMurray formations", if there's any more specificity required there?

A That would be the reservoir zone.

Q Thanks.

And are you able to provide a justification based on the evidence in the record for monitoring of zones outside of the Wabiskaw B gas?

A So the Clearwater is mentioned as -- because it's the caprock. So you would want to monitor for integrity of the caprock. The Wabiskaw D is mentioned because that's the bitumen-bearing formation closest to the Wabiskaw B shut-in assets. The McMurray formation is mentioned as meaning the reservoir zone so that you can have a direct measurement -- indication of temperature and pressure development in the steam chamber. And the Wab B obviously is the zone of interest.

Q Thanks.

And you'll note that my question is limited to the zones that are outside of the Wabiskaw B. If I asked ISH for a ranking in terms of preference between the three, could you provide one?

A Yeah. Let me confer for a minute.

Q Yeah.

A So ISH is obviously interested in what's happening to their Wabiskaw B asset; right? We also appreciate that while the well is there, there is an opportunity to monitor more than one zone; right? So there is a matter of efficiency there where, you know, it would be valuable for CNRL to get information in the bitumen-bearing formation as well as their caprock and also at the same time be able to monitor ISH's gas assets.

So in terms of preference, it's really a matter of perspective, so I -- I really -- you know, whether you are CNRL or whether you're ISH, I think they're all relevant, and they provide data that can inform changes in -- in the formations.

Q Thanks.

Now, in terms of ISH's preference, could I -- could I have a witness on behalf of ISH -- are they able to provide a ranking in terms of the preference between the three zones outside of the Wabiskaw B?

A J. CHODZICKI: Yeah. Just conferring on that.

So obviously from -- from ISH's standpoint, Wabiskaw B is important for -- most important for us, but then we would look at -- for the wider perspective of -- of what information could be gleaned, and it would be the Clearwater caprock, and it would be the

Wab D and the McMurray. So then with those zones, you could then tell if something unusual is happening from the McMurray to the Wab D to the Wab B, which is most important for ISH. And obviously -- heaven forbid we ever get up to the Clearwater -- then we've got bigger problems in the area. But those would be the -- in an ideal situation of monitoring -- a thorough monitoring of a SAGD operation, that would be the -- kind of the preferred intervals.

Q Thanks.

Just want to make sure that I'm understanding that evidence correctly. So the preference as stated -- obviously the Wab B is the zone that ISH, you know, produce -- or intends to produce from in the long-term. But after the Wab B, the evidence was first Clearwater as it's the caprock, then the Wab D, then the McMurray in terms of a preference or -- and feel free to contradict or say that you can't make a preference.

A So further suggests McMurray first -- obviously Wab B, then McMurray, then Wab D, then the Clearwater. So I had that backwards.

Q Great.

A But Wab B is --

Q So McMurray, Wab D, Clearwater in terms of --

A Correct.

Q -- ISH's preference? Thanks.

Now, can you explain what the basis for that stated preference is just with respect to each zone specifically, please, and, if possible, in relation to the issues identified for this hearing?

A A. LAGISQUET: So operations will be in the McMurray formation if we look at KN08/KN09; right? So that's where the steam is being injected. That's where we would want to have temperature and pressure information.

Then through the evidence, I believe we conveyed the fact that because of the close proximity stratigraphically between the McMurray and the Wabiskaw D and, you know, the risk of overconductive heating and potentially overpressuring if the barrier -- if a barrier present and -- and forms like undrained condition, you would also want to -- to measure temperature and pressure there to kind of inform what's happening from the bottom up; right?

There is obviously clear concerns around caprock integrity. I think we discussed that at length through the last few days. So obviously it's a zone of interest. But looking at ISH's interest, we would want to look at then the Wabiskaw B first and then the caprock. So it's not a matter of which one is more important. I think they all give you different information that is valuable to try and understand

what's happening. And the data is never used in isolation; right? You use -- CNRL mentioned that a few times. This is an integrated workflow. So the information from an obs well would never be used in complete isolation.

Q Thanks.

And just to clarify in your response, I believe you referred to discussions over the last few days about integrity of that caprock. By that, I'm assuming you meant the confining strata that we've been discussing as opposed to the Clearwater, which is identified as the caprock in -- in ISH's submission?

A Well, we -- we discussed both, right, when Dr. Chalaturnyk yesterday reviewed the geomechanical model. You know, he made a point that the modelling is adequate when you are looking at caprock integrity -- addressing caprock integrity questions. Where it may be less adequate is to evaluate whether the confinement strata would act, you know, as -- would provide integrity, you know, and protect the Wabiskaw B.

Q Thanks.

Now, Ms. Lagisquet, I'm interested, I think, primarily in your evidence on this question. But what would be the incremental cost, in your view, of instrumenting a well in each of these formations as we've discussed? Say -- for example, adding -- if

you're going to the Wabiskaw B to instrument it, what's the incremental cost increase to a well to -- to add the other formations?

A And that assumes that the well is already there, right, and the well can be instrumented? Is that the -- the assumption and -- I need to make?

Q It's probably worthwhile to explore both that assumption and if it's not already there.

A Yeah. So I would say if the well is already there and assuming that it's compatibility with the type of instrumentation that we suggest to add, it would be minimal incremental cost, I would say. It's difficult to quote because it would -- it would depend on what we land on the number of zones that we -- we land on monitoring, number of thermocouples, and so on and so forth. But I would say in the -- yeah, 75, 100K. I would be --

Q So is that to say 75,000 to $100,000 per additional zone to be instrumented for monitoring --

A No, no, no.

Q -- or --

A Total.

Q Total?

A Yeah.

Q For -- for all of the zones?

A Yes. I believe so, yeah.

Q And in -- that's in the case where you've got a preexisting well that goes all the way into the McMurray?
A Yeah. There could be much less.
Q Now, in the case where you don't have a preexisting well that goes all the way into the McMurray, what would be the incremental cost increase?
A Yeah. I would say an incremental well would be in the order of 3, 400K.
Q Is that per zone or for all three?
A No. That would be the whole vertical well all the way to the -- the McMurray.
Q Thank you.

And that -- so to understand that evidence, it's -- the hypothetical well would be a new well that's the incremental cost increase to change it from being simply drilled and instrumented for the Wabiskaw B to being drilled and instrumented for the McMurray formation? Is that --

A That --
Q -- the --
A No. That would be a brand-new well.
Q That's what I mean. So the -- the cost increase -- you've got two hypothetical wells, one that's drilled to the Wab B and instrumented to monitor that, one that's drilled to the McMurray formations and

instrumented for all of the formations you've identified. The difference in cost between those two wells, in your view, would be on the order of what?

A J. CHODZICKI: So I think you're assuming if there's a well that we drill and then we want to just monitor the Wab B versus three other zones. So that's where I think we would -- there would be another 75,000 -- say -- say they cost 25,000 to monitor the Wab B -- assume the well is drilled. Assume it's in place. Then you monitor the Wab B, and -- and, again, that cost could be 25 to 50,000. Then you're monitoring other zones at the -- at the same time. Now, we don't have a full feel for what these costs are, but we're assuming that -- perhaps another 25,000 per zone. So say -- that's where we come to the 100,000 or so estimate. But it's -- once you have a well in place, and then you've got to run wirelines and -- and -- and the monitoring sensors at the certain depths. That's where we're trying to come up with a ballpark estimate.

Q Thanks.

And do we have evidence, then, that would suggest what the cost difference between -- we'll call it sort of the Cadillac, I guess, well versus the Honda -- sorry to all Honda owners in the audience, but ...

A I think that's -- that's where, you know, there is a --

a disagreement when we have that in that one table that showed the -- the multi-well piezometers and the number was coming to a very high amount. You know, depending what the use is for other wells -- say you have to have a strat well to properly define the geology. Say you have to do a DFIT test on a well to get a better feel. There are some synergies that can be obtained, and that's what we're hopeful for. Again, we are not experts on what CNRL has in house for actual costs and where there could be some cost savings.

Q But am I correct, though, in understanding that Ms. Lagisquet is an expert in these types of projects and can opine on the cost -- you know, the ballpark cost of -- of doing --

A A. LAGISQUET: Yeah.

Q -- these types of things?

A Yeah. So the ballpark cost of a well, that would be -- with, like, three to four zone being instrumented with thermocouples and piezometer -- would be in the order of 3 to 500K. Like, it's really hard to give you, like, an absolute estimate, but I'm sure there could be some cost efficiencies that could be found too; right?

And so if you want to contrast that -- the cost estimate that Canadian Natural provided, I think we would have to compare the assumptions that were made for the cost because it's -- it's really hard for me,

you know, to -- to -- to tell where that 2.4 million, I believe, that was quoted came from. I'm not saying it's wrong. I'm not saying it's right. We would have to see the assumptions that were used.

Q Thanks.

And now I will ask the witness panel to just confer and review paragraph 141 if possible. So if we could get the entirety of it up on the screen, and then, panel -- witness panel, let me know if you have trouble reading it or anything. And just to confirm, all of the subparagraphs, so(a)(i) through (iii) all the way down to (g) of subparagraphs of paragraph 141.

Let me know, I guess, when you've reviewed.

A Yeah. I think we're good.

Q Thanks.

Based on the evidence that's come out through the hearing and the process leading up to now, are there any monitoring conditions that you would change or remove from this list?

A Based on the information that was exchanged during this -- this hearing -- and I'm talking about the last four days -- and the clarification around the solvent-assisted start-up in particular, I think potentially dropping the -- the monitoring conditions around solvent -- and it's also the fact that that monitoring is primarily associated with de-risking a

technology that is not yet commercially proven. So really it would be a choice that Canadian Natural makes to de-risk that technology, and it doesn't necessarily impact ISH's interests.

Q Thanks.

Anything else in that list, or is that it?

A J. CHODZICKI: Looking at the -- the items, obviously we -- ISH is not that concerned about the SAGD, but the Wab B is always the monitoring that would be of interest to us. And thus having adequate monitoring in the Wab B with sufficient monitoring wells properly located to be able to check for variations in temperature and pressure over the SAGD pools still is valuable information both for ISH and for CNRL.

Q Thanks. But --

A A. LAGISQUET: And when we say -- sorry. When we're not concerned about SAGD, and we're not concerned about SAGD performance per se. We're concerned about the impact that SAGD could have on the Wab B. I think we made that very, very clear. But, again, we appreciate that an observation well would be primarily to monitor the performance of SAGD, right, not -- it has an indirect impact on how you manage to monitor the gas zone in -- in the Wabiskaw B; right? So there would be some efficiencies again there. If

you end up draining a well, why not monitor all the zones to guarantee the absence of impact. So I would be in the middle between the Cadillac and the -- and the Honda right there.

Q Thanks.

Just to confirm, the question is very specifically about whether there's any changes to this paragraph and the monitoring conditions. I think we've explored the --

A Yeah. So that would be primarily on the solvent-assisted monitoring.

Q And no other amendments or deletions?

A No.

A J. CHODZICKI: You're talking just on the solvent paragraph or on other parts -- other --

Q No. All of paragraph 141(a) through (g) --

A Right.

Q -- is there anything you'd take out?

A Right. And that's what we're talking about, (a), we could -- we could definitely relinquish the desire for more monitoring of the other zones. But I just wanted to touch on perhaps the Wabiskaw B should have some monitoring, especially if SAGD operations are imminent in the Wabiskaw D zone, which is very close to the Wabiskaw B zone. So we would say, Yeah. We could get by with less monitoring with the multi-zoned piezometer

wells, but we would want to monitor the Wabiskaw B, and perhaps there should be one point that is used to monitor the Wabiskaw D as well, which is so close to the Wabiskaw B.

A A. LAGISQUET: Yeah. And that -- that's part of finding those efficiencies. You know, like, we've -- we've seen that there is that KN25, I believe, that could be a future pad, and obviously as you get higher in the stratigraphy, then you get closer to the Wab B. So I think it's in everybody's best interest to try and monitor that zone as much as possible to ensure that there is no impact, or if there is impact, then we can remediate it.

Q Thanks.

So then -- and, again, please just focus on the act -- the question that I'm asking here because I don't need to have further explanation in response to the answer necessarily.

But the next question is: Is there any monitoring condition that should be there but is not contained in paragraph 141? Anything that you would add to the monitoring conditions based on what's come out in the hearing process or even also specifying certain monitoring conditions, for example, the placement of the monitoring well, et cetera? If there's anything like that, let us know.

A So we did identify a location for the monitoring well already, and it's at -- in my report, so it's there for reference, if necessary.

But, no, to your question with the exception of the -- of the solvent monitoring, we wouldn't add or remove anything.

Q Thank you.

A J. CHODZICKI: I'll add to that. If we could pull up Exhibit 15.01, page 106, Tab 3, and we could just talk through this diagram a bit because this gives useful context.

So you see on the right side the 10-1 well. The 10-1 is the current monitoring well. That's the current monitoring well and essentially supports what is happening at the KN06 pad, and we see there is some distance to the other.

So the 10-34 was the one we talked about yesterday, will be potentially a monitoring well. That will be useful information for KN08, of course subject to assuming the proper Directive 020 regulations are followed with the downhole abandonment of the McMurray, and ISH has supported CNRL on converting this to a monitoring well. That's useful information.

We see the yellow star -- the yellow star is the proposed 1-3 monitoring well location. ISH supports that -- that well, and, you know, again, the full

details of what will be proposed for that well is still to be determined.

And we see up by KN09 -- if we look -- we talked that gap yesterday in that KN09 pad where there is about 600 metres in between strat tests, which looks like an insufficient well density to fully determine what is there. And then where this 10-2 shows as another -- that's another GOB well that's been shut in, but there was talk yesterday about the proposal to drill a new strat test just to the northeast of approximately this location. That would be useful information. Also, CNRL would learn some more about the Wab D at that location, and that could be another good monitoring well to include. So that's kind of the location of the potential monitoring wells.

The advantage of monitoring wells is -- we talked about -- they talked about temperature diffusion yesterday and how temperature effects are much slower than pressure effects. Now, I think pressure effects are still slow in a reservoir considering there is variation of permeability, and we have seen the variations of pay thickness through here. So that's where more monitoring wells come into play. But to just say, One monitoring well at one location of 10-1 is sufficient, well, no, we don't think it's sufficient, but that's why we see there is now

application to do more monitoring here.

And so temperature -- it's not just you're monitoring the pressure. You are monitoring the temperatures also, which could be an indication of some kind of premature breakthrough happening or something strange happening that you might want to know about. So that's what we -- you know, we're looking at for monitoring, is just to give the aerial context on the map.

Q Thanks.

Now, I just need to confer a little bit before moving on to our next subject matter. Thanks.

Now, zooming in a little bit on some more monitoring conditions and potential approval conditions, et cetera, we'll be talking about gas composition analysis, and ISH refers to that specifically -- and, actually, if we could go back, please, to Exhibit 32.02, page 46 I think we were looking at. It's paragraph (c), (d), and (e), which I -- yeah. They're all on para -- page -- I think it would be 46 -- or 45. Sorry.

What type of gas compositional analysis and at what frequency should these analyses be conducted during the life of the KN08 and KN09? And if you could support that answer when you're providing as well.

A A. LAGISQUET: Okay. I will start on this

one.

So the proposal to collect gas samples is to have a mean to be able to evaluate if the Wabiskaw B gas pool has been contaminated or not, right? So you would want to test before SAGD operations commence, and you would definitely want to test when they're completed, right? That being said, if something has happened and you haven't had any data point in between to indicate a gradual contamination of the pool, the only thing you can say is that the pool has been contaminated, right, instead of being able to monitor as time goes by. So it would be preferable to be able to have data points in between the pre SAGD and the end of SAGD.

In terms of frequency, my colleague and I agree that annual would likely be a good -- a good frequency to be able to monitor the changes in gas composition.

And to address your question, what we would be looking for is deltas against the baseline composition.

Q Thanks.

Now, in terms of a baseline composition, are you aware of any gas samples that have already been collected and analyzed from the Kirby Upper Mannville II gas pool?

A J. CHODZICKI: I think you're talking historical -- historical samples. Yes, there have been some historical analyses. I think in one of ISH's IRs,

I believe we provided some -- some baseline samples. Also, of course, we would want to see a new baseline sent now because -- just to confirm now with SAGD operations what is the current baseline.

Q So is there any -- I guess can you point us to a reason in evidence or through analysis as to why previous gas samples may or may not be suitable for the purpose of establishing a baseline?

A A. LAGISQUET: It's just because of the advantage. They're pretty old. They're pre-GOB shut-in obviously, so in fairness also to CNRL, I think it would be going to have a baseline that we can all agree upon, and so collecting gas samples now pre SAGD would be preferable in terms of quality of the data.

Q Thanks.

Now -- now, you would have heard Canadian Natural's witnesses describe the process required to obtain a gas sample through their direct evidence. Do you disagree with that process or the description of that process in any way?

A J. CHODZICKI: So part of it -- part of new samples could be done as part of a new well drilling if you were to perforate that zone. We understand CNRL's concerns about them wanting to produce the well for a bit, which in some cases you'd have to have some kind of temporary exemption to be able to produce that well

for a bit, and I understand CNRL's concern that there would be some costs. And we're talking on a shut-in well -- a shut-in well that's -- should be still tied in, could be produced for a bit, but they're talking about trying to clean that well up a bit because it had been shut in for a while. So you would produce it for a bit, and then you would sample that gas. So it did sound a bit arduous. You know, maybe you could do something a little simpler. It's a hard -- I'm not fully aware of what -- what they're proposing exactly, but in principle I understand that there's some work required.

Q So I guess in general, then, you don't have any strong disagreement with what Canadian Natural's witnesses presented as the process that would be required to obtain a gas sample from a -- from the relevant pool?

A A. LAGISQUET: Yeah. Provided that it's feasible to -- to be -- to reopen a GOB shut-in gas well for the purpose of collecting a gas sample. I think their description was correct in the sense that you would have to flow the well for a while to ensure that you have a representative sample, and I think that's the whole purpose behind collecting a new sample versus using historical samples, is to ensure that at the end of the day we are representative.

Q Now -- and bear with me. It's a little speculative,

but would it be possible to identify some other monitoring condition, the pressure temperature, et cetera, over time, that is a little bit more easy to monitor than a deviation in which could trigger a requirement to collect a gas sample?

A J. CHODZICKI: Yeah. That -- that would be a reasonable compromise, that, you know, the pressure and temperature differences over time are what could trigger all of a sudden a need to understand there's been a sudden change in temperature that may indicate something is breaching. And you could say, Okay. We need to do a closer work at this well and grab a proper sample. That's a fair statement to make.

Q So you've identified pressure and temperature as variables that could be monitored as a trigger point perhaps for gas compositional analysis. Are there any others?

A A. LAGISQUET: I can take that one. The challenge is the -- the response time, right, and the interpretation of -- of those pressure and temperature data. So the closest you are to the zone, the easier to get, again, representative information. So the preference would be collect the gas sample. We appreciate it might be complicated to do that, but that's the best -- that's the best option.

Q Thanks. And thank you as well for the segue into my

next subject.

On time lines, what would be a reasonable time line, do you think, in terms of either between some other triggering event saying, We need to take a gas sample or between a gas composition sample demonstrating some anomalous result and a response being required? What's a reasonable amount of time in those types of situations?

A So I'm going to try to answer your question.

Q It's a bit of a long one. Sorry.

A Yeah. And -- and the challenge with answering is the fact that it's really hard to interpret data in isolation, and I think that's what we've seen through this -- the conversation we've had over the last few days.

And so taking information from a single data point and -- and hoping that that data point is going to tell you the whole answer is -- is an incomplete approach; right? And that's why we're proposing a series of monitoring conditions. Because in isolation, they wouldn't be able to tell you the full story.

So now, you know, going back to monitoring well, like we understand -- the time line -- it takes time to establish a trend. By the time you establish trend, you know, assuming that the well is actually giving you -- giving you accurate data, it could take a while

and it could be too late. And that's why we want obs wells in combination with gas compositional analysis to understand what is happening over time.

Q Thanks.

Now, just to clarify, I think the evidence that you've presented speaks for itself in respect of the value of multiple data points in relation to monitoring. In parking that issue, if we could move in very specifically to the time lines. What would be a reasonable time line if the data available suggests that there are adverse events occurring in relation to steam migration? What's a reasonable time line for an operator to report that to the Regulator and for there to be corrective action applied to -- to remedy the situation if it's identified?

A J. CHODZICKI: Okay. So I understand with the 10-1 monitoring well there are some monitoring conditions in place that CNRL report unusual changes in pressure and temperature to the Regulator. I understand that there is an annual report that gets filed on the performance of a SAGD. The 10-1 monitoring well will be filed with the next -- I think it's Directive 54 -- I can't remember -- report. But, you know, if the data is obtained monthly, ISH gets a copy of that monthly data. So I would assume, upon an unusual change in temperature or pressure, that could

be reported fairly soon, like, within a month after it happening if we're getting the data every month, as opposed to waiting for the annual performance report of the SAGD project. So I think if an unusual temperature or pressure change -- I think -- I thought the word was they're to notify immediately, which one -- you know, one month is pretty immediate compared to an annual report -- then that would then suggest that you need to do some follow-up investigation right away to determine what is causing this unusual change. And an unusual change wouldn't be, like, 01. It would be something -- say you're off a degree or your pressure has suddenly jumped up a couple hundred kilopascals or something like that. So I think it would be fair to say immediate, which would imply, you know, within a month to try and understand what has happened.

Q And then I guess the second part of that question would be in relation to what's a reasonable time frame in which ISH would want to see a corrective action or mitigation strategy, however you want to phrase it, in the event that some adverse condition is -- appears to be occurring?

Like, how long do you have once the pressure transducers tell you something weird is happening between then and when the steam gets to the gas, that type of a question?

A So I just wanted to clarify. Are you talking the first step is to first understand what is going on, which would imply, like, take a gas sample first? That would be the first step. And then you would try to understand what -- what has happened, that were gas analysis, a sample would come in handy at that point in time. As for other mitigating measures, let me confer.

Q I think -- just to clarify, I'm trying to provide as little structure here as possible in the response. I just -- I want to -- I want to better understand the urgency or the time line with which a response would be necessitated based on the issues we've been discussing in this hearing for the last three-and-a-half days.

A A. LAGISQUET: So I'm going to attempt an answer here. You would have your gas compositional analysis. You would identify acceptable bounds in terms of results, and as long as they are within those margins that would be considered, you know, an acceptable data point. If you start going off track on your results, that's when you would want to take action, and that would be probably a collaborative kind of approach with CNRL to understand what data we're seeing, how it's being interpreted, and take the corrective actions. One of them might be, you know, reduce your steam rates, for instance.

I would say once the gas starts being contaminated

there is no turning back. So in terms of remediation, the only appropriate remediation I would see is reduce your steam rates, reduce your pressure to minimize -- to attempt to minimize the impact. But the risk at that point would have materialized.

Q Would there be any other mitigative or corrective actions that you think might be worth contemplating and time lines on which to implement those in response to observed anomalies and data?

A J. CHODZICKI: So thinking about that, we would -- again, with additional monitoring, it gives you the potential to compare what's happening at the one well to the other wells to make sure this isn't some unusual data spike.

I know we've mentioned as another monitoring condition surface recorders; right? Surface recorders compared to downhole recorders could also indicate is there some weird difference. Because as we discussed for 10-1 in our filings, that not knowing what's happening downhole -- and we're -- we're confident we can get the proper mechanical configuration of the gauges downhole -- then we still want to have double-checks on those gauges with surface recording.

And then looking at the location of that anomaly that gets observed, comparing it to other recorders, other observation wells, we can then say, Is this some

localized phenomenon or just a bad gauge that needs replacement? So at that time we would attempt to say, Hey, there's something unusual here; you need to look at this.

As for what happens -- if it's truly an event and the subsequent gas analysis says, Yeah, we've got some high CO2 and high H2S gas that's suddenly noted, at that point, there's not much really we can do. It's out of -- it's out of our hands, and it just becomes a matter of time, then, as to how other parts of the field respond, which is where you then have the other monitoring wells to see if there's a temperature or more a pressure change that can be observed at these other locations that then gives you the -- some -- some confidence that, Okay. It's more localized. Hopefully it stays local and we don't see this -- these effects spreading. Of course, over time, yes, H2S will diffuse -- other gases will diffuse, but if it's localized, hopefully we can just live with that one event. But once it happens, it happens. Like, we're not experts on how you would try and block that from happening, if it has happened.

Q Thanks.

Moving on -- away from conditions, et cetera, and monitoring, I know I said earlier that I finished talking about fractures, but I misled you. My

apologies for that. We're going to go back to a discussion of fractures, Issue Number 1, presence of -- or potential presence of faults and fractures.

If we could pull up, please, Exhibit 32.02 at PDF page 22, paragraph 59. And if we can just zoom in on that one, please. Thanks.

So here ISH's submission states that the interpreted FMI logs show evidence of fracturing below the McMurray zone between the McMurray and the Wabiskaw zones and above the Wabiskaw zone. And the statement is that: (as read)

> This confirms ISH's interpretation that there are existing fractures in the strata underlying KN08 and KN09.

So we've heard some evidence on this, heard it discussed. But now if we could please go to Exhibit 32.08 at Tab 4. It's PDF page 46. Oh, there we are.

So the FMI interpretation and summaries shows a summary of fractures identified at different intervals within the 9-33 well. Yesterday the question was asked on where these fractures occur and at what intervals. So can ISH provide approximate intervals where these fractures are projected to occur?

Sorry. I'm hearing that that's already been addressed. So we can move on more to the fracture

density, I think, which was the -- the more point about this.

So in the -- unless you've got more on that, but I think I already asked that earlier. Yeah. I realized it as I was reading it.

So moving on to the subject of stratigraphy and fractured density, so yesterday it was described that the fracture density approached maybe approximately five fractures per metre in a confined layer. We just are seeking clarity here as to whether this is over all of the confining layer, like all six units that Canadian Natural has identified, or within a single kind of sublayer of that and, if so, identify which sublayer.

A K. VICKERMAN: Okay. So -- so on the plot, the fracture density is the -- the magenta-shaded areas on the third and fourth tracks from the right-hand side. And the -- the difference between these two, the -- the one that's on the third from the right-hand side is the fracture count. So that's the number of fractures encountered in a -- a 1-metre sliding window.

The next track over is fracture density, and that's a -- a calculated number. So if you have a -- an inclined well -- or if you -- if you have a well and hit a fracture that's steeply inclined to the borehole, it's -- you're less likely to hit it. And if you now

hit several of those things that are less likely to be hit, if you project the presence of an unlikely feature laterally, it -- it implies a density in a -- in a volumetric sense.

And so the -- for instance, if we look at just below 546, there's -- there's three fractures there. And that -- the -- the fracture density -- each track there is counting two fractures per metre. And so it's saying that it's a more -- bit over four fractures per metre is -- is the volumetric density of those fractures at that depth.

You know, this -- this isn't enough data to do a distributive fracture network analysis, that kind of question. That's a -- that's a bigger -- bigger question, I think, is, you know, how -- how many fractures are there present everywhere. But, you know, it's -- if you were to say that the -- the confinement interval is at 520 to, you know, perhaps 560 on this plot and we encounter -- two, four, six -- seven fractures in that metre -- or in that interval -- so it's not -- as I said, it's not highly fractured, but there are fractures present.

I would note that these -- I wouldn't expect -- if you had a -- a well, say, 10 metres away from this well, like, very close, you wouldn't necessarily see fractures in the exact same stratigraphic layers. They

would be -- tend to occur in -- in layers that have similar mechanical properties. So -- and -- and that may be a fracture in the layer of -- above where we see it in this well or below where we see it in this well. But, overall, you might expect to see fracture density similar to this nearby.

Q So just in the spirit of confirming the evidence and confirming our understanding, you did a little kind of back of the napkin type of calculation there for fracture density over the -- the kind of confining strata that we've been talking about. Could we just confirm what those numbers are? Can you have a quick look at this exhibit and -- and the strata that we were talking about earlier and look at the number of fractures and do the division there for us?

A So we're -- we're seeing seven fractures in this -- however many there is -- 20 -- 35-, 40-metre interval. So -- --

Q So 7 over 35?

A -- sure. So that would tell you the -- the density of fractures that are in the orientation that this well can sample. So there -- this well has a particular deviation that's -- if you look at the track on the -- on the left side, there's a -- a tadpole track there. The long tadpole is pointing down towards where the well is drilled. So this well is drilled in a -- in an

inclined southeasterly direction, and so it's going to tend to see fractures that are striking perpendicular to that trend.

What you can't tell from this is whether there are fractures in the opposite direction that are parallel to that -- the deviated wellbore trend. And so it's -- it's unknown to project sideways on this.

Q So I guess the -- understanding fracture density, then, in that context, it would probably be better to phrase it as "observed fracture density" for that well?

A That's fair. If you were to combine this with the other well, which was drilled in an orthogonal direction to it that saw fewer fractures, you might start to develop a picture that, you know, maybe there are seven fractures in that confining strata observed by this well, and the other well that was not too far away and drilled in a different direction saw two or three -- whatever that number is. You might combine those two together and say, you know, this describes what the -- the fracture network might look like.

COMMISSIONER CHIASSON: Mr. McClary, Commissioner Barker has a question following on.

W. MCCLARY: Yeah.

COMMISSIONER BARKER: Thank you, Mr. McClary.

Mr. Vickerman, on this line of questioning, of these wells that you're saying that are about seven

that you've identified in this well, how many of them are drilling induced and how many of them are naturally occurring, in your opinion?

A So the ones that we picked as the magenta-coloured ones are naturally occurring. The -- the drilling induced are those -- the -- the ones that are near the centre of the tadpole track with a grey circle and two lines pointing out in -- in -- in opposite directions.

COMMISSIONER BARKER: Okay. And then --

A So there's three of those on -- in that interval here.

COMMISSIONER BARKER: Okay. Thanks.

And then in your -- were you able to interpret of any of those fractures, the naturally occurring fractures that were closed or -- versus open?

A K. VICKERMAN: Yeah. So I've only -- I've only spoken to the magenta ones. The magenta ones are those that we think are open because they have -- they have that conductive appearance.

There are a number of the yellow -- the smaller yellow fractures that are here are the healed fractures that we've identified. And that was using that line of evidence about it's overconductive on the inside of the cusp or the trough and -- and often a very subtle appearance as opposed to conductive looking, like the -- the magenta ones that we have.

COMMISSIONER BARKER: Okay. Thank you.

Thank you, Mr. McClary.

A Yeah. So, I mean, on that point, that means that there is actually a higher total fracture density if you include the -- the healed versus the -- the open here. So there -- there are a couple of healed fractures in that -- in that interval. So, you know, do you count seven? Do you count nine?

Q W. MCCLARY: Thanks.

And then I guess in terms of identifying them in the stratigraphy, your approach -- if -- if you are asked to identify them in that way would be, again, to go back to CNRL's picks on the zones and then using a calculation as we've described to count the fractures over the -- the height of the -- the zone? Is that --

A K. VICKERMAN: Yeah, I think that's fair.

Q Thanks.

A I -- I -- I would -- I would suggest that because there's been disagreement in the intensity of fracturing between my interpretation and CNRL's that it would be worth looking at other wells to get a -- a better picture because I -- you know, some of the features that were -- a lot -- three -- a lot of the features that were described as "tool marks" by the -- my opposite interpreter -- I -- I disagree. Some -- some were borehole breakouts falling features; some were image processing features. And if -- if

everything's called a "tool mark", maybe nothing's a tool mark. So I -- I have suspicions about that.

I would -- you would want to look at -- look at the whole thing. I would -- I would look at all the wells, and then you can get a -- a better idea. There -- there's not that many fractures in here, so whether --

A A. LAGISQUET: Again, it's back to being -- is it representative --

A K. VICKERMAN: Yeah.

A A. LAGISQUET: -- right --

A K. VICKERMAN: Yeah.

A A. LAGISQUET: -- looking at two wells out of --

Q Thanks.

And I'm really just investigating the -- the use of the -- the unit as described -- like, the -- the fracture density.

A K. VICKERMAN: Yeah. When you have a sparse -- a -- you know, a modest number of fractures like this, it's -- it is hard to upscale it to a -- to a larger sense. You always have to -- am I on?

Q You're on, yeah.

A You have to make sure that you remember the geometry of the measurement, you know, which direction was the well in, and -- and take note that you may have areas, you

know, like the -- the southern end here that have more fractures and may -- you may have other areas that have fewer fractures. And you do that by looking at the data you have. And -- and that it is fair to look at particular units and -- and summarize that there may be two in this unit and none in that unit, but it's -- it's a -- a measurement of a -- of a diffuse and, you know, varying density open space.

Q Thanks. I'm just trying to let you finish here.

W. MCCLARY: I am cognizant of the time, and I have two more questions that I think might require a small amount of conferring between the witness panel, and then my colleague, Ms. Peddlesden, has a few more questions. I think maybe two -- two questions, five minutes max. I'm hopeful that we can finish before lunch, Commissioner Chiasson. Is that possible here?

COMMISSIONER CHIASSON: I was just thinking about time check because I'm -- our reporters will need a break soon, so ...

W. MCCLARY: Yeah. I think we could be done in a matter of seven or eight minutes here.

COMMISSIONER CHIASSON: Okay. Let's -- let's proceed then.

Q W. MCCLARY: Now, as I mentioned, this next question might require a little bit of conferring

between the witnesses, but keep in mind that we got lunch. Take your time. If answers need -- need you to confer, go ahead.

Can anything be inferred from the density of healed fractures in the strata that we were concerned with?

A K. VICKERMAN: Yeah. I don't think so. I think it's common to see open and healed fractures together. There would be a tendency for, in particular, the lithologic units to heal up more and others to -- that's a -- it's common to see them mix like this.

Q Thank you.

Now, in the -- and this is the last one for real. Do we have in the data that we have in the hearing -- based on the data that's been analyzed and presented, et cetera, are we able to assess whether there's connectivity between fractures that exist or if there's a sufficient fracture density to suggest that there's fracture pathways that are present within the relevant confining strata, and, if so, what would your assessment be on that? And maybe what we'll do is I'll switch places with our SMEs here while you guys confer.

A So from the two wells that I looked at, I don't -- I don't know if you can make that statement or confirm or deny it necessarily.

A J. CHODZICKI: So the only way to conclusively tell if you see evidence of fractures that may or may not be a connected path would be to do a DFIT test. That's where you, then, establish is there truly a problem in a certain area. The individual fractures just suggest there is potential for that, but the DFIT test is -- will more conclusively state is this rock competent?

Q S. PEDDLESDEN: All right. So I'll wrap up with a final question, if Will confirms that's good to go?

And I'm Ms. Peddlesden. I'm here to ask you about Issue 5, the thermal compatibility.

S. PEDDLESDEN: Ms. Arruda, please put up Exhibit 15.01 at page 502.

Q S. PEDDLESDEN: So these are the four wells, three of which ISH is a WIP and the operator. I just wanted to go through them quickly.

Number 1, is ISH aware that any well integrity issue must be reported to the AER on the digital data system, the DDS?

A J. CHODZICKI: I believe we are aware. If there's a problem with the wellbore that -- yeah, the DDS is how you submit if you observe some problem with the wellbore.

Q Thank you.

And Canadian Natural reply submission includes work over proposal schematic diagrams that show -- and they also verbally confirmed on Wednesday -- that there is thermal cement behind the production casing on each of these wells. So I just want you to confirm -- and this should be fairly brief -- that ISH has not identified a well integrity issue.

So I'm going to have you lump all three wells, so that would be Well 10-02, 10-03, and 10-34. And I'm just going to give you a series of integrity questions.

So the first one: Has ISH noticed surface casing vent flow?

A I would say no. A surface casing vent flow would have to be reported, and I haven't heard any reports of surface casing vent flows.

Q Gas migration?

A I would say, no, we haven't observed any gas migration.

Q Evidence of casing failure?

A No.

Q Evidence of wear that would affect well integrity?

A No. We haven't gone to that depth to review wellbore integrity downhole.

Q Any other evidence of communication behind the production casing?

A We haven't observed definitive evidence of communication behind casing.

Q Have you observed any evidence of communication behind casing?
A No. There was only these theories in a previous submission discussing 10-34, and nothing was substantiated from that.
Q Are you speaking to submissions to Proceeding 430?
A In the -- this proceeding there's the 10-1 investigative report that references the 10-34 well, but we, again, don't have any concrete evidence of behind-pipe communication. There was a previous report done for 10-1 that was submitted as part of this proceeding in various submissions, and there is no concrete evidence of behind-the-pipe flow of compromised integrity.
Q To help me out, where was their concern?
S. PEDDLESDEN: Ms. Arruda, if you could put it to page 503.
Q S. PEDDLESDEN: And, Mr. Chodzicki, please use the mouse and speak verbally in a way that the transcript would cancel -- or -- pardon me -- capture where you're pointing.
A Okay. The -- their 10-34 and -- there's -- I might have my wellbores mixed up, actually. Let's look at 10-2 actually. Yeah. Scroll down, Tab 38.
Q Yeah. It's just the next.
A Yeah. I'm mixing up -- I think I'm even mixing up my

wellbores. As I look at 10-2, it's got perforations in the Grand Rapids, and it has perforations in the Wabiskaw. So there was some talk -- I believe it was the 10-2 well that discussed in the 10-1 investigation report that had some talk about potential behind pipe flow, but we don't have evidence of that. We see there is a -- a removable packer there. Nothing has been investigated on that.

And I recall yesterday your suggestion of a CBL log. That would be the one way you could determine behind pipe integrity. No, we have not done that.

So back to 10-34, I now see that 10-34 -- scroll down to Tab 39, please.

Q 10-34 is up, if that helps. It's at 503.

A Yeah. Sorry. Sorry. Yeah. Go up.

So 10-34, this is the one that was discussed yesterday about making it a monitoring well. So, again, we don't have any evidence on this one of behind the pipe. It was the 10-2 well I think I was referring to, that possible flow to the Wabiskaw.

The only concern we had with this one which was stated yesterday: (as read)

Will the McMurray be properly abandoned with cement on the case section of the well that goes over the McMurray?

So that was our one comment internally that you brought

up yesterday about the need for proper cement across the McMurray SAGD zone. So --

Q Yeah. And that was my next question. Was your thoughts on Canadian Natural's response that they would run a pulsed neutron spectroscopy log, a PNX log, at Well 10-34 thereby justifying keeping it open so they could put the wire down on an annual or once every two years.

S. PEDDLESDEN: And, Ms. Arruda, just to help out, could you put up page 224, same exhibit.

Q S. PEDDLESDEN: So Canadian Natural proposed using Well 10-34 to run a PNX log and get this type of data?

A If -- if the Regulator doesn't have a problem with the zone staying open -- and this is useful data -- then we could support it provided there is the casing integrity and the cement integrity. So if this is legal to do, to get this kind of information, that would be helpful for everybody to understand the SAGD performance. So as long as it's legal.

Q And I would like to speak to what the concerns would be with the thermal drainage box, being -- like, if we look back at 503 -- or pardon me -- 502, page 502. And if you could note if 10-3 4 is in the KN08 drainage box. So just speak to the risks, please, Mr. Chodzicki.

A Well, it is a good point that 10-34 could only monitor only the very edge of the drainage box where you might not even see much SAGD development. So location isn't the greatest for that type of -- of measurement. Perhaps you could still gain some information, but 1-3 -- think of where the 1-3 observation well, that would be more suited to the centre of the SAGD development for that kind of logging.

So, again, I can't comment if the Regulator allows CNRL to get that kind of log information. ISH doesn't have a problem with it. But it doesn't appear to be the best suited within the SAGD box, considering it's right at the edge, however, still valid for monitoring the Wabiskaw B gas zone.

Q And would you be concerned about deformation of the production casing?

A I think that could be a risk. So that -- you know, if you start seeing very high temperatures at that well -- and, again, I'm not sure how this monitoring of these wells that aren't fully thermally compliant is allowed by the Regulator. I'm not -- I'm not an expert on these regulations, but I understand that the preference is to cement off that McMurray and that would then fully comply with the regulations. But if -- if you allow someone to do that and it's legal, there still could be a risk of some casing deformation, but maybe

in time that's part of the monitoring. We say, Hey, this temperature is too high. We need to act on this now and cement this off.

Q And just when you were responding to my previous question, I noticed you mentioned that 1-3 would be an appropriate monitoring well. Was that the well that you meant to mention?

A No. I'm talking 10-34 here 'cause we're talking the 10-34. I'm assuming 1-3 is --

Q No, no. Sorry. Mr. Chodzicki, this happened just a little while ago. I just want to make sure the record is correct. And you stated that 1-3 --

A As proposed --

Q -- is in the middle.

A Yes. As proposed by CNRL. 1-3 well is proposed as a monitoring well for the Wabiskaw. It's already drilled.

Q I misunderstood. I thought you meant to say 10-3, and I didn't want the record to stand. Thanks.

Okay. I appreciate that.

J. JAMIESON: We're good to go for lunch unless the Panel has questions.

COMMISSIONER CHIASSON: All right. Thank you.

The Panel has no questions. Before we break for lunch, Ms. Riley, can you advise, does ISH intend any redirect?

M. RILEY: ISH does not intend to redirect.

COMMISSIONER CHIASSON: Thank you.

So then, Ms. Jamieson, my understanding is that CNRL does have some -- is intending to do some rebuttal?

J. JAMIESON: Possibly. And if -- I actually can't say definitively right now. If we could break for lunch, we'll certainly come back --

COMMISSIONER CHIASSON: You would like the lunch break to consider that.

J. JAMIESON: If we could, please.

COMMISSIONER CHIASSON: I am assuming that we are sound to release the witness panel for ISH, so thank you all very much. We appreciate the time that you spent there.

(WITNESS STANDS DOWN)

W. MCCLARY: Sorry. Commissioner Chiasson, just one thing to flag, I guess, would be I don't think the AER has any questions for CNRL or for Canadian Natural that remain, subject to there being any rebuttal evidence. So it could be the case that we would go straight to -- straight to closing; right?

COMMISSIONER CHIASSON: Yeah.

J. JAMIESON: Fair enough. I think that is one scenario.

W. MCCLARY: Yeah.
J. JAMIESON: Because that's us up first. We'll come back and tell you one way or the other. We'll either be a little bit of rebuttal or prepared to do our final argument.
W. MCCLARY: So with that in mind, do we want a little bit of a longer lunch?
J. JAMIESON: That would be great, if we could have it.
W. MCCLARY: That's where I was going.
J. JAMIESON: Thank you. Appreciate that.
COMMISSIONER CHIASSON: How -- how -- how much longer -- how much longer do you suggest, counsel?
J. JAMIESON: Yeah. Fair enough. Is it possible to restart at 2:00? So it's over an hour. An hour 20.
COMMISSIONER CHIASSON: Yeah, we're looking at not quite an hour and a half, then. I think -- I'm assuming that's -- that's acceptable. That still gives us the timing to -- to -- to fit -- to fit in because the other thing I guess I would flag is that I am aware that there are a few people that have travel arrangements end of day, so we do need to be live to that.
J. JAMIESON: Understood. And I can tell you that if we do any rebuttal, it's going to be brief,

like 10 to 15 minutes. There's just a couple of things that we may need to respond to.

COMMISSIONER CHIASSON: All right.

So any concerns about that timing, Ms. Riley? No. Okay. So we will break now. We will reconvene at 2:00 and then see quite where we're going then. Thank you, all.

PROCEEDINGS ADJOURNED UNTIL 2:00 PM

Proceedings taken at Govier Hall, Calgary, Alberta

February 9, 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 2:03 PM)

COMMISSIONER CHIASSON: Okay. So welcome back.

Ms. Jamieson, I believe you were to -- to update us on which route -- which route we're going now.

J. JAMIESON: We are going both routes.

COMMISSIONER CHIASSON: All right.

J. JAMIESON: So we do need to re-seat a witness, Canadian Natural witness briefly. I want to bring Mr. Peter Thomsen up. It should only take five or ten minutes, but I think we -- it's important that we do so.

COMMISSIONER CHIASSON: All right. So I had a previous hearing where we did this, and so what I'm going to suggest that we do is when -- when we bring Mr. Thomsen up, perhaps your first question could be just to get him to affirm that -- and I don't recall whether -- whether he was sworn or affirmed, but just to confirm that he's still bound by that previous affirmation.

J. JAMIESON: Absolutely. We could go

either way. I've given the court reporters a heads-up that we could ask that he be reaffirmed.

COMMISSIONER CHIASSON: Okay. Super. Thank you.

THE COURT REPORTER: Do you want me to re-swear --

J. JAMIESON: I think that would be efficient.

PETER THOMSEN, Re-sworn

J. Jamieson Re-examines the Canadian Natural Resources Limited Witness Panel

Q J. JAMIESON: Thank you. So I said five minutes, Mr. Thomsen, and then you brought all your big binders, so that wasn't to scare anybody.

The question is simply: Ms. Peddlesden yesterday had questioned Canadian Natural on their intentions -- the intended workover for the 10-34 well. We heard Ms. Peddlesden came back to that question with the ISH panel in terms of the plan.

Can you please reiterate what Canadian Natural's intention was and then address Ms. Peddlesden's questions, please?

A All right. Good afternoon, Commissioners.

So previously with respect to Ms. Peddlesden's questions about the 10-34 well, Canadian Natural -- we had previously communicated, and we were not planning to place a cement plug in the 10-34 well below the existing perforations and across the McMurray

formation.

Subsequently, we have reviewed a directive, the AER Directive 20, to ensure our plans are -- are compliant with directives, and upon further consideration, we have realized that the McMurray formation should be cemented. Canadian Natural will be placing a cement plug across the McMurray formation.

Q Thank you, Mr. Thomsen.

So that would be subject to any questioning from the staff or ISH. Thank you.

COMMISSIONER CHIASSON: Any questions on that, Ms. Riley?

M. RILEY: None.

COMMISSIONER CHIASSON: Thank you.

Ms. Peddlesden?

S. PEDDLESDEN: No.

COMMISSIONER CHIASSON: Good. Then no questions. Thank you, Mr. Thomsen. You are released. That was nice and -- nice and quick in spite of the -- Ms. Jamieson's misgivings about your binders. So thank you.

(WITNESS STANDS DOWN)

COMMISSIONER CHIASSON: So, then, I -- we're good to proceed to -- to closing?

J. JAMIESON: We are. Maybe indulge us. If we could have five minutes. I do have a hard copy of

the -- of the final comments on its way.
COMMISSIONER CHIASSON: M-hm.
J. JAMIESON: And being old school, of a vintage, I really prefer the paper, so if you're okay with that.
COMMISSIONER CHIASSON: I understand that. You may have seen the binders that I keep flipping open, and that -- that's fine.
And, Ms. Riley, will you want -- will you want a few minutes after Ms. Jamieson is completed with hers?
M. RILEY: Yes. I would appreciate that.
COMMISSIONER CHIASSON: All right. Thank you. We'll -- we'll -- five? Ten? What? Any idea, or do you want to wait and hear what she has to say?
M. RILEY: Probably I suspect that what I can get done in five, ten won't help, so --
COMMISSIONER CHIASSON: Okay. We'll -- we'll give you a break, then, after that. All right. Thank you.
So we will just relax then for five minutes or so.
(ADJOURNMENT)
COMMISSIONER CHIASSON: So, Ms. Jamieson, we are ready whenever you are.
Final Submissions by J. Jamieson
J. JAMIESON: Thank you.
Good afternoon, Commissioners. On behalf of Canadian Natural, I want to thank you all as well as

the AER staff and legal counsel for your time and attention in reviewing the evidence in this proceeding.

I'm pleased to be here this afternoon to make these closing remarks on behalf of Canadian Natural.

As the Panel is aware, this is an application to amend Commercial Scheme Approval Number 11475 for the recovery of crude bitumen from the Wabiskaw/McMurray deposit by adding two new steam-assisted gravity drainage boxes to the Kirby project, KN08 and KN09. Specifically, this application is for the recovery of crude bitumen from the Wabiskaw bitumen zone only and does not include the Wabiskaw D bitumen zone.

Canadian Natural made its amendment application pursuant to Section 13(1) of the Oil Sands Conservation Act and the AER Draft Directive 023, Category 3 amendment. In its amendment application, Canadian Natural identified ISH as a petroleum and natural gas rights holder in the KN08 and KN09 boxes. ISH and Canadian Natural are working-interest partners in the Kirby Upper Mannville II gas pool.

Canadian Natural engaged with ISH over the course of several months by providing a draft copy of the application and confidential core logs to examine plus responding to its concern within the application at pages 12 to 15 -- that's Exhibit 001.01 -- and meeting in person on at least two occasions to try to resolve

ISH's concerns. The parties were unable to come to an agreement and are here today requesting this Panel's assistance in resolving the issues between them.

Canadian Natural has provided a map showing the relative positions of the KN08 and KN09 drainage boxes and the Kirby Upper Mannville gas pool. Sorry. I may have misspoke already.

So I just want to be clear that the recoveries of the crude bitumen is from the McMurray bitumen zone and does not include the Wabiskaw D bitumen zone. Yeah? Sorry. I must have misspoke.

All right. So we did provide this map. It shows the relative positions of the KN08 and KN09 drainage boxes in the Kirby Upper Mannville 2 or II gas pool. That's Exhibit 022.02, PDF page 5. ISH based its statement of concern and request to participate in this hearing on the potential for adverse effects to ISH's gas production. Specifically, as we understand it, ISH's concern with the potential for Canadian Natural steaming operations will lead to an increase in H2S in the gas pool and thereby souring it from the currently sweet gas stage.

In its -- in its submission ISH asserted that it is directly and adversely affected by Canadian Natural's intended bitumen production because the conditions of approval Canadian Natural proposed:

(as read)

... do not make adequate provision for the conservation of ISH's overlying gas interest.

And the reference for that is Exhibit 32.02, ISH's submission, PDF page 5, paragraph 1.

Canadian Natural understands that ISH does not seek an order preventing Canadian Natural from developing the bitumen resources, but rather is asking that in the event the application is approved, in the public interest the Panel imposes the conditions set out at pages 44 and 45 of ISH's submission. That's Exhibit 32.02, ISH submission, PDF page 10, paragraph 22. And I believe those were modified to some extent by the questions asked by AER legal counsel this morning -- or this afternoon -- this morning.

On September 6, 2024 -- '23, this Panel set out five hearing issues, which I'll address in detail in a moment. In our view, the key decision that this Panel needs to make is whether Canadian Natural SAGD operations at the KN08 and KN09 boxes present a risk to ISH's overlying interests in the Wabiskaw B gas pool, and if so, whether Canadian Natural's proposed mitigation measures are reasonable in the circumstances.

Canadian Natural submits that the technical evidence filed in this proceeding demonstrates that

there is an effective barrier between the McMurray formation and the Wabiskaw B gas pool and that there is little to no evidence of an open fracture network that could increase that risk. Further, Canadian Natural's proposed mitigation measures and monitoring program are reasonable, given the nature of the potential effects, the practicability, the effectiveness, and an examination of cost versus benefits.

Canadian Natural requests that the application be approved and that the approval be conditioned on Canadian Natural's proposed mitigation measures and monitoring program.

So I'll just take a step back. The legal framework for this application is well established pursuant to the Responsible Energy Development Act, REDA, this Panel's task is to determine whether the application should be approved with --

THE COURT REPORTER: Ms. Jamieson, slow down a bit, please.

J. JAMIESON: Oh. Sorry. Too fast? I will.

-- with or without conditions.

Section 2 of REDA states that the AER's mandate is in part to: (as read)

... provide for the efficient, safe, orderly and environmentally responsible development

of energy resources in Alberta.

In arriving at its decision, this Panel must also consider certain factors in its governing legislation, including the Oil Sands Conservation Act, and the Oil Sands Conservation Rules. Section 3 of the Oil Sands Conservation Act sets out certain purposes, including to effect conservation and prevent waste of the oil sands resources of Alberta and to ensure orderly, efficient, and economical development in the public interest of the oil sands resources -- of the oil sands resources of Alberta. It also includes ensuring the observance in the public interest of safe and efficient practices in the exploration for and the recovery of crude bitumen.

Section 3 of the Oil Sands Conservation Rules, specifically Subsections (3) to (5), make it clear that conservation of the oil sands resource is to be safeguarded by ensuring bitumen reservoir pressure is not reduced through production of the overlying gas.

REDA and Section 3 of the Responsible Energy Development Act General Regulations also require this Panel to consider the social, economic, and environmental effects of the proposed energy resource activity.

Canadian Natural submits that the only potential -- or the only effects that need to be

considered in this application that are relevant are economic and that the economic factors should be part of the Panel's assessment of the potential consequences of adverse impact to ISH, and I'll come back to that shortly.

ISH has also raised in the context of this proceeding the application of the Oil and Gas Conservation Act. In particular, ISH has argued that an approval under Section 13 of the Oil Sands Conservation Act cannot be contrary to the Oil and Gas Conservation Act.

Canadian Natural agrees that the OGCA is relevant to this proceeding. The purpose of the OGCA is in effect to -- the conservation of and to prevent the waste of oil and gas resources as well as the responsible management of wells, facilities, and sites throughout their life cycle.

As a majority and joint owner of the gas resource, Canadian Natural shares a mutual interest in and responsibility to protect the overlying gas zone while pursuing the development of the bitumen resource.

Canadian Natural has acknowledged its responsibilities in this regard and believes it has proposed a safe and responsible approach to the development of bitumen. And for that, I'll reference Exhibit 15.01, PDF page 6 of 61, as well as

Mr. Iannattone's comments in his opening statement.

With respect to your task in evaluating the evidence, we note that the AER Panel for KN06 -- for the KN06 proceeding was faced with very similar issues to the ones being heard in this proceeding. We understand that you are not bound by the AER decision report in that proceeding; however, we would suggest that this Panel could take a similar approach.

In the KN06 proceeding, in addition to the hearing issues, the Panel set out to answer two overarching questions: Number 1. Do we find that Canadian Natural's proposed operations as permitted by the approval may cause direct and adverse effects to ISH? 2. If the answer to the first question is "yes", are there reasonable steps that could be taken to avoid and mitigate these effects?

In considering what is reasonable, the KN06 Panel determined what was reasonable in the circumstances depends on the nature of the potential effects, as well as the effectiveness and benefit of the proposed mitigation measures.

I'll turn very briefly to the gas over bitumen decisions. I know that this Panel is very familiar with those decisions. I don't -- you know, I'm not going to go into any detail, but I would like to highlight a couple of points that I do believe are

relevant to this proceeding.

First, it was in the Energy and Utility Board's Decision 2005-122 in which the EUB relied on conclusions from the 2003 regional geological study and shut in a number of gas wells, including those in the Kirby Upper Mannville II gas pool. The stated goal at the time was to maintain adequate pressure in the bitumen reservoirs -- reservoir to ensure efficient production of the bitumen resource. Essentially, the bitumen resource was given priority in time.

Since then, gas producers, including Canadian Natural and ISH, were extended -- have been extended compensation for the shut-in gas through the Alberta Energy Royalty Adjustments as outlined in the Alberta Natural Gas Royalty Guidelines. For Kirby Upper Mannville II pool, Canadian Natural's accounting records indicated that compensation of approximately $6 million has been provided in royalty adjustments to Canadian Natural and ISH relating to the shutting in of the pool.

And that information is on the record, but I can't point you to the exhibit.

The third takeaway from the GOB decisions is that where souring of GOB, gas over bitumen, is a risk, it is a monetary one; one that is compensable.

The KN06 Panel also recognized that the potential

effect of souring the gas from bitumen-bearing sediments over time is the generation of H2S through aquathermolysis, and that's paragraph 2008. I'll just give you the KN06 proceeding decision so it's on the record: AR Decision Report 2021, ABAER 001.

The KN06 Panel also included that the nature of this potential adverse effect is commercial. Paragraph 219.

Canadian Natural acknowledges that H2S contamination of the Kirby Upper Mannville II pool is a potential consequence of steam from the McMurray reservoir reaching the Wabiskaw P -- B during the producing life of the KN08 and KN09 boxes. However, based on the technical evidence, Canadian Natural asserts that this is a very low risk and that when weighing the benefits and costs involved, its proposed mitigation measures are reasonable.

With this -- respect to evaluating this potential impact, this Panel will need to review and weigh the technical evidence. This is a very familiar task to the AER and is certainly one that we would ensure or trust that you will do.

You're also being asked to weigh different types of technical evidence: core samples, image logs, seismic, GCMS. Some of it is stronger evidence than others.

You also heard Canadian Natural speak of its integrated workflow, and to that I would point you to Exhibit 50.003, Tab 4, PDF page 49, and, again, Mr. Iannattone spoke about it in his opening comments and as well Mr. Lavigne stated specifically how their technical workflow applies to determining the stratigraphic framework and the geological conditions of the proposed boxes.

The power of an integrated workflow is the accuracy and consistency of results when multiple datasets support the same conclusion. We ask that you put the most weight on the consistency of Canadian Natural's results.

The Panel must also characterize the nature of the asserted risk. First, to determine whether there is, in fact, a risk. A concern is not a risk. We ask that the Panel give due consideration as to whether or not there is an actual risk based on the totality of the evidence or whether some of the concerns raised by ISH are actually perceived risks. We also ask this Panel to recognize that the potential risk can be characterized as monetary only and thus can be adequately accounted for by compensation if, in fact, they do come to bear.

I'll just take a moment, please.

All right. I'll turn now to the technical

evidence, if I could, and this would be a review of the -- the five hearing issues.

Now, the first hearing issue, Canadian Natural did sort of separate it into two parts for the purposes of addressing both in their submissions but as well in the presentation by the Canadian Natural witnesses.

The first part of the -- the hearing issue is -- the first hearing issue is whether there is an affected barrier overlying the bitumen-bearing McMurry formation consisting of a deposit or aggregate of strata that is not permeable to steam over the life of the KN08 and KN09 drainage boxes.

In Canadian Natural's view, the evidence clearly demonstrates that there is an aggregate of strata overlying the McMurray formation that is not permeable to steam over the life. Over the KN08 and KN09 drainage boxes, there are six identified confining strata units, and Mr. Lavigne, you heard him walk through them from the bottom up. So from the Fort McMurray or -- sorry -- McMurray formation up through the six units. So starting with the post-B non-reservoir, the mid-B1 mudstone, the A2 mudstone, the Wabiskaw D non-reservoir unit, the basal upper Wabiskaw D heterolithic unit, and, finally, the Wabiskaw C at the top.

Canadian Natural provided operational evidence

that barriers and baffles within the post-B2 reservoir -- so starting at the bottom just above the reservoir -- they would be predicted to stop steam chamber rise often below the mudstone-prone inclined heterolithic deposits of the post-B2 non-reservoir unit. This is in the form of the Kirby north PNX logs shown at Exhibit 15.01, Tab 12, page 224.

Next -- try again. Okay. Next, Canadian Natural asserts that the mud -- the mid-B1 mudstone, which is sitting in the middle of that regional B1 sequence, so we have the lower B1 sequence, then we have this nice clean mid-B1 mudstone, and then the upper regional B1 sequence. So it's the one in the middle that they turn to. That mid-B1 mudstone is correlatable across the drainage boxes and is consistently identified in core.

Now, the mid-B1 mudstone is generally recognized as a marine flooding layer and where it's present is capable of sealing. So we have a number of references on the mid-B1 mudstone to substantiate that there is ample evidence on this point.

So the core photos can be found at Exhibit zero -- that doesn't look right. This is the application: 01.01, PDF pages 127 through to 268, and, again, pages 331 through 381.

In the hearing submission, Exhibit 15.01, Tab 06, PDF pages 109 to 192, and, again, same exhibit number,

15.01, Tab 14, PDF pages 226 through 325. And the last one -- the same? Oh, okay. I see. Thank you. Sorry. There's a range of exhibit numbers here. 42.03 through 42.44, and 43.003 through 43.185.

All right. Canadian Natural also relies on the evidence that it filed -- the GCMS evidence that corroborates the existence of the mid-B1 mudstone, and there we would have you look to Exhibit 15.01, Tab 11, PDF page 219, PDF page 220, and PDF page 223.

And, finally, Canadian Natural provided a rollup summary of all of its evidence, not just on the mid-B1 but all of the formations, and that was provided in the form of an Excel table, and it is really a catalogue of the core photos, the image logs, and the well tops of the confinement strata. And for that, we would ask you to review Exhibit 43.197.

You've heard some differing views from ISH on whether or not the mid-B1 is present over the majority of the KN08 and KN09 boxes. However, when we ran Mr. Barrie back through those image logs, he can clearly detect mid-B1. He, in fact, identified the mid-B1 in one of the areas where he had -- so within the blue polygon where he had earlier stated that it was absent, he did, in fact, identify it on the screen. Where he wasn't comfortable identifying it as a mid-B1, he did indicate that it was potentially part of that --

a muddy consequence.

Again, I want to stand corrected. It was the core photos. You'll recall the map in the middle with the blue polygon. So we talked about the core photos that were around there. Thank you.

Now, further support was provided for the barriers in this unit, meaning the B1 sequence. That was supported by the GCMS data, and Dr. Fowler recognized this in his report. And Dr. Fowler's report can be found at Exhibit 32.09, Tab 5, page 4, lines 33 to 35.

Turning now to the A2 mudstone. The A2 is also recognized as a regional A2. So where it is present, it's generally recognized that it is sealing. The A2 at the KN08 and KN09 drainage boxes is present along the southern third and along the edges of the KN08 drainage box where it is expected to act as a barrier, and the A2 isopach is provided in Exhibit 15.01, Tab 15, PDF page 326.

Now, turning next to the two Wabiskaw D zones, the first one, Wabiskaw D, contains two high volumes of shale units that act as confinement strata. In both the Wabiskaw D non-reservoir unit and the basal upper Wabiskaw D heterolithic unit, even though individual mudstone beds may not have large lateral extents as a unit, it is Canadian Natural's submission that they do have the ability to act as barriers. And this is

supported by the presence of a gas cap between the latter unit in the 1AE/10-2 well on the KN09 box. This well not only verifies the presence of a barrier in an area of relatively thin confinement strata, but it also demonstrates how a unit with 50 percent volume of shale can hold back gas caps and, by extension, steam.

Core photos that best display the sealing capacity for the gas cap were provided in Exhibit 01.01, PDF pages 370 to 381; Exhibit 15.01, Tab 16 and Tab 17. These are the isopachs of the Wabiskaw D confining strata units. This is also supported by GCMS data in this well, which is located in Exhibit 15.01, Tab 11, PDF page 222.

Next we have -- or the last-to-the-final on the top is the Wabiskaw C. It's an argillaceous -- that's the first I've had to say that -- heterolithic mudstone and sandstone succession that is present over the entirety of both boxes. The distribution of the Wabiskaw C is presented in Exhibit 15.01, Tab 19. Canadian Natural has advanced its understanding of the Wabiskaw C since the original GOB rulings discussed -- those were discussed this morning. I can't remember which witness it was, but one of the ISH witnesses spoke of this.

As hundreds of more wells have been drilled in the Kirby north development area since that time,

sand-filled burrows identified on core photos within this unit are discontinuous and vary in distribution from well to well. A torturous connected pathway from these burrows is highly unlikely. The best evidence for this is a review of the Wabiskaw C core photos as catalogued in Exhibit 43.197.

The combination of the units will serve to isolate steam from the SAGD operations in the McMurray from the gas zone at the Kirby Upper Mannville II pool. Canadian Natural restates its view that the confinement strata as an aggregate of units will act as a barrier to contain steam over the life of the Kirby -- KN08 and KN09 operations.

Canadian Natural utilizes -- sorry -- Canadian Natural utilizes a multidisciplinary approach to the evaluation of its oil sands assets. Multiple datasets have been presented by Canadian Natural which demonstrate the breadth of data included to create a comprehensive geological interpretation. A stratigraphic framework evolves out of the combined datasets of wireline logs, core, image logs, and 3D seismic. For identifying effective containment strata, the stratigraphic framework is foundational.

And just as no one confinement strata unit is relied upon for steam containment, no single piece of data is relied upon for defining the confinement

strata. Direct and indirect data are corroborated to provide a full assessment. An example of this is the use of GCMS data by Canadian Natural to identify potentially -- sorry -- potential barriers and baffles, both in the reservoir and confinement strata. When used in combination with stratigraphy, GCMS is a tool which predicts -- which is able to predict which low permeability layers within the stratigraphic column will likely be barriers to steam.

Just in summary on that first part of Hearing Issue Number 1, Canadian Natural reiterates that it is not relying on one marine mudstone layer, the A2 mudstone, or one flooding surface mudstone, the mid-B1 mudstone, although both are present at different parts of the boxes, but rather it is the combined package that they've defined by the six units that will work together to effectively contain steam.

So I'll turn now to the -- the second part of hearing issue -- the first hearing issue, which was about the low fracture density in the confinement strata, or what is the fracture density. The second part of Hearing Issue Number 1 is whether there are fractures in the strata between the McMurray formation and the Wabiskaw B member that could potentially impact the risk. Canadian Natural has been drilling and operating SAGD wells in the Kirby area now for over

11 years. It has extensive knowledge of the stratigraphic layers as well as the lack of faults and fractures in this area.

Canadian Natural has drilled cored logged [sic], including image logs, and reviewed several hundred stratigraphic test wells at Kirby north, including 43 within the proposed KN08 and KN09 drainage boxes, and conducted in-depth analysis of its 3D. And then an explanation of that can be found further at Exhibit 15.01, page 30 -- PDF page 30, paragraph 27.

In the context of this proceeding, Canadian Natural has submitted substantial geological and geophysical evidence that illustrates it is highly unlikely that an open and connected fracture network exists in this area. Now, support for that is -- there's multiple points for that. No faults or natural fractures were observed within confinement strata intervals on core data from 24 wells at KN08 and KN09, and that support is found in Exhibit 15.01, Tab 23, page 337.

There was disagreement -- you heard it this past week -- between Canadian Natural on the presence of fractures at KN08 and KN09. ISH has argued that there are -- there were several wells with fractures observed on core photos. However, Canadian Natural -- Canadian Natural's evidence shows that all of these fractures

were coring-induced.

Dr. Wang provided evidence of his interpretation of the image logs, and he repeatedly confirmed that Canadian Natural's evidence is that anything that was being seen could be identified as tool marks.

So the 36 image logs that you have on the record here, no natural fractures were observed. That's Canadian Natural's evidence on that point. And you can look to Exhibit 15.01, Tab 23, page 337.

Now, Mr. Vickerman did testify that he had analyzed a subset of the image log data which was supplied to ISH, and he, in the end, only reviewed 2 out of the 11 image logs supplied by Canadian Natural. He confirmed this morning that the fracture density observed in these two wells is what he characterized as "sparse" in his report, so low fracture density.

You also heard yesterday that a feature identified as a fracture from ISH's publicly available image logs at the 1AA/11-2-075-09-W4 well was later reviewed by Mr. Vickerman and was likely characterized as "a bit" or a tool mark, not a natural fracture. And that should be on the transcript, the February 8th transcript, PDF page 78 of 238, lines 9 to 13.

Furthermore, Canadian Natural's seismic -- 3D seismic evidence, their interpretation confirms that

no large-scale faulting from salt dissolution or Paleozoic karsting is present at the KN08 and KN09 boxes. Seismic structure and attribute mapping also shows no evidence of fractures or large-scale faulting, and so that -- we would ask that you take a look at Exhibit 01.01, page 28, Section 2.83.

Now, with respect to differential compaction, Canadian Natural has acknowledged that a minor amount of differential compaction does exist at the KN08 and KN09 boxes. It can primarily be associated with overlying mud-filled abandonment plugs. These features have been mapped on -- with 3D seismic and further tested with stratigraphic test wells, which have shown no evidence of faults or fractures with the confinement strata. I'm just going to see if I can point you to the map that shows that.

We're going to verify for a moment that I didn't misspeak again, and we're going to keep moving so that we can get through this.

So also with respect to differential compaction and the impact of it, Canadian Natural's evidence showed that there was no lost circulation events during the drilling of 43 stratigraphic test wells and no lost circulation events during drilling of 16 producer injection -- injector wells at offsetting KN06. And that evidence, I believe, points to whether or not

there are existing natural fractures when they go to drill. The exhibit number for that is 50.02, paragraph 65 -- sorry -- page 20, paragraph 65.

Another point to be made on low density faults and fractures, the pressure data between the McMurray bottom water leg and the Wabiskaw B Kirby Upper Mannville II gas pool indicated no connectivity between the zones that would be indicative of open faults and/or fractures. This data also confirms if natural fractures did exist but remain undetected at KN08 and KN09, they are closed to fluid -- flow, including steam. And for that we would point you to Exhibit 15.01, Tab 26, page 340.

Finally, we would point to Dr. Boone's supplementary report. This is one of the things that he reviewed and looked at, and his evidence showed that in the event -- or his assessment showed that in the event that fractures within the confinement strata exist but are undetected due to the ductile nature of the confinement strata shales at depth, they are most likely closed to fluid flow. That's found at Exhibit 50.03, Tab 1, Appendix C, page 26, paragraph 5.

So to sum up on that part of Hearing Issue 1, Canadian Natural evidence, in our view clearly demonstrates that no fractures exist that would pose a risk to steaming operations over the life of the KN08

and KN09 drainage boxes or, in the unlikely event that they do exist but are not detected they are closed to fluid flow, including steam.

I think the stickies are flying, so I'm just going to take a moment and make sure I didn't misspeak.

I just want to go back and drive some clarity around the number of image logs. So I believe Canadian Natural's evidence -- yeah -- show -- it's just this clarity between numbers and who reviewed what. But Canadian Natural's evidence is that they have reviewed 36 image logs within the confinement strata, and no natural fractures were observed. 11 image logs went over to ISH as part of this proceeding, and it was those 11 that I had referenced earlier.

All right. Let's move forward. Hearing Issue Number 3, this is the maximum operating pressure and what's appropriate in the circumstances.

So Canadian Natural did conduct a thorough geomechanical evaluation of the containment risk, both under conditions of the temporary SAGD start-up pressure proposed at 6,600 kPa and also for the long-term SAGD operations at an MOP of 6,000 kPa, and it included a review of the relevant start-up experience in situ stresses and geomechanical modelling.

Results of these investigations, in Canadian

Natural's view, clearly demonstrate that the confinement strata will contain steam and reservoir fluids in the McMurray formation.

Now, Canadian Natural has modified its request. We put this on the record, and the point of it was not for technical reasons, but really it was a willingness to consider ISH's concerns and respond with what they could.

So for the requested temporary MOP of 6,600 kPa, two additional constraints have been committed to. One is a maximum continuous time of 24 hours when using bottom-hole pressures above the 5,500 kPa and below the temporary MOP of 6,600 kPa; and, two, a maximum gross steam rate of 180 cubic metres per day -- there's a CWE -- I don't know what that acronym is for, but perhaps somebody technically competent will -- so 180 cubic metres per day when using these BHPs above the 5,500 kPa. And you'll find the commitments on the record.

Canadian Natural shows that the temporary MOP is not always used for circulation start-up, and when it is used -- this is their -- the bulk of their experience -- it is only used for very short durations and for limited volumes.

Canadian Natural is also prepared to reduce its long-term MOP of 6,000 kPa to 5,500 kPa, and the MOP of

5,500 kPa will be used during and after the application of the proposed hydrocarbon agent solvent-assisted start-up.

Evidence was presented of erosion of a portion of the B1 sequence and thinning of the mid-B1 mudstone; however, the mud-dominant lower B1 is present everywhere, and this will act as a stress barrier.

Canadian Natural has used DFITs to characterize stresses. The objective of a DFIT is to induce a small hydraulic fracture to interpret minimum in situ stress values. DFITs do not test for connectivity of natural fractures. We heard a little bit of that on the record this morning. I think there's some confusion there. Canadian Natural has interpreted their minimum in situ stress using what they believe to be the best practices, and the characterization shows a minimum stress gradient difference of 1.5 kPa per metre. The stress profile having a higher minimum stress in the mudstone-dominant B1 than the underlying sand is widely accepted due to the higher mud content strata having higher Poisson's ratio.

Dr. Chalaturnyk stated that the Poisson's ratio under loading will result in differential stress that will be exhibited in -- in a difference in the stress contrast. Yes. So that's what's on the transcript, February 8th, page 143, lines 6 to 8.

Dr. Boone's report, which is found in Exhibit 15.01, PDF page 92, 93, Dr. Boone finds that with regional DFITs, quote: (as read)

> As it is commonly observed that shales or mudstones will have higher minimum in situ stresses than underlying sands or reservoir facies, it can be concluded with a high degree of confidence that McMurray mudstones will have a stress contrast relative to the McMurray sands that exceeds the 0.5 kPa per metre.

Now, Canadian Natural, you know, is providing this evidence because ISH has asserted that an additional DFIT is necessary. In Canadian Natural view, that is simply not the case. They feel that they have provided sufficient evidence on the record that it's not needed, and we would point you to Exhibit 50.02, PDF pages 50-51.

Canadian Natural has also relied on some academic literature to support the concept that in situ stresses tend to be regionally consistent for the same stratigraphic unit. Regionally present mud-prone heterolithic strata such as the regional B1 sequence have consistently similar elastic properties. In addition, the historical Kirby north 146 well data set per circulation start-ups does not show low fracture

pressures or variable fracture pressures.

We just also want to point to the -- this historical Kirby north 146 well data set for circulation start-up, and that can be found -- that demonstrates regional stress consistency -- at Exhibit 50.002, paragraph 187.

In the -- again, one of the things that Dr. Chalaturnyk agreed with was that the historical Kirby north circulation start-up data can be used to understand McMurray stress variations in the Kirby north area. The reference for that is the draft transcript, page 140, lines 17 to 18.

So I think the point of that, again, is that this historical circulation start-up data supports the regional stress consistency within the post-B2 reservoir and the regional B1 sequence.

In Exhibit 50.003, PDF pages 20, 24, the risk consequence of potential start-up steam communication from the post-B2 reservoir to the Wabiskaw B gas is conservatively assessed as between 10 million and 100 million. This is a financial risk only since there are no reaction products in the condensed steam during circulation start-up. That would be Dr. Boone's report, I believe.

Sorry. Yeah. I'm getting tired. Late in the day here. Yes, this was the question in that table as

well. Those are a thousand dollars, so ten thousand to a hundred thousand.

So this incremental expense of an additional DFIT, in our -- in Canadian Natural's view, is disproportionate to the consequence of the risk event, and it's also unclear how a DFIT would result in a further risk reduction, most notably because we already have a reliable stress contrast between the regional B1 sequence and the post-B2 reservoir sand. Proposed operational limits for the temporary MOP of less than 24 hours and a maximum steam rate of 100 cubic metres per day and thus a new DFIT would not change the requested temporary MOP for initiating circulation.

Further, the long-term MOP has already been reduced from an acceptable 6,000 kPa to 5,500 kPa, which increases factors of safety. So, again, an additional -- or additional DFITs in the vicinity of KN08 and KN09 would not change the requested long-term MOP of 5,500.

And just to take a step back with respect to containing the risk during short-term circulation start-up, so this is at the 6,600, the risk of fracturing through the confinement strata with start-up bottom-hole pressures up to 6,600 kPa is really negligible, in Canadian Natural's view, due to fracture containment mechanisms that limit potential fracture

growth. And those include -- and I believe Mr. Thomsen went through them -- a leakoff within the McMurray reservoir confinement strata, a stress contrast between the McMurray reservoir and the confinement strata, elastic stress increases within the McMurray reservoir, limited rate and volume injected with elevated pressures.

Furthermore, the geomechanical modelling confirmed that the risk of fracturing during start-up with bottom-hole pressures up to 6,600 kPa is extremely low due to the multiple fracture containment mechanisms, and that -- the modelling that confirms that is at Exhibit 46.002, PDF page 61 to 72.

Dr. Chalaturnyk, in his evidence, confirmed that in his review he had, quote: (as read)

> No issue with the GeoSim fracture modelling conducted of the temporary start-up and evidence that Canadian Natural has provided around fracture containment within the McMurray during the start-up of the SAGD process is convincing.

That's in the February 8 transcript, page 140, lines 14 to 21.

Dr. Chalaturnyk also confirmed that the work with the temporary MOPs was convincing, so, no, he did not have a problem. Lines 8 to 9.

Containment risk during long-term operations. The long-term MOP of 5,500 kPa is equivalent to 76 percent of the shallowest base of the Clearwater shale minimum stress. Oh -- sorry -- this is a reference they're providing for this: Exhibit 01.01, PDF page 31.

The entire KN08 and KN09 drainage area is underlain by a bottom water interval, and that's shown in Exhibit 01.01, page -- PDF page 44, Figure 210. Canadian Natural interprets the reservoir sand to be in communication with the bottom water sand over almost the entirety of the KN08 pad. McMurray bottom water necessitates SAGD steam chamber pressures to be similar or balanced to the McMurray bottom water pressure over extended periods. It would be highly impractical to attempt SAGD operations at a steam chamber near the long-term MOP of 5,500 kPa due to unsustainable losses of steam into the bottom water. Additional geomechanical modelling was used to confirm that there is minimal risk of confinement strata integrity over the long-term SAGD operations up to an MOP of 6,000 kPa.

And I don't think I'm going to take you through all of those modelling reports, but we would point you to the geomechanical modelling report, again, Exhibit 46.002, PDF page 61 to 72.

Dr. Chalaturnyk did identify some concerns with

the modelling specifically related to handling small-scale heterogeneities in the confinement strata properties. You may rely on that exchange. And that was at page 113 of the February 8th transcript, lines 1 to 9.

It is Canadian Natural's view that the uncertainty in the modelling results due to these modelling details would not significantly impact the comfortably high factor of safety predicted to be present for the proposed long-term MOP.

I think I'm going to just check, if I could, with my colleagues and make sure there isn't something critical there I should have covered.

All right. We are moving forward. As you are aware, Canadian Natural addressed the Hearing Issues 2, 4, and 5 together because they had to do with no appropriate monitoring conditions or conditions of approval that -- that the Panel may be considering.

So Canadian Natural set out its proposals for its view of appropriate monitoring conditions at paragraphs 129 through 158 of its hearing submission. That's Exhibit 15.001. And a detailed monitoring strategy was also included as Tab 28, exhibit -- same exhibit number.

Canadian Natural then gave due consideration and updated its monitoring proposal in recognition of ISH's

ongoing concerns and requested monitoring conditions, and you heard about some of that. Mr. Ollenberger reviewed these updates as part of his direct evidence, and these now include converting the 100/1-3 well from a standing cased well to a Kirby Upper Mannville II pool gas monitoring well prior to steaming of KN08 and KN09, equipping the 10-34 well as a gas monitoring well as an additional location on Pad KN08, and as well providing a fourth gas monitoring well on or in the vicinity of the KN09 pad.

These monitoring well commitments in combination with the 10-1 well exceed ISH's request monitoring well commitments -- or requested.

Sufficient mobility in the Kirby Upper Mannville II pool supports that a specific location on KN09 is not required to provide adequate monitoring on the KN09 pad. In addition to the four gas monitoring well locations just mentioned, baseline and pre-production gas samples will be collected by Canadian Natural from the Kirby Upper Mannville II pool and can be presented as part of annual -- its annual Directive 54 presentations, if requested, as part of any approval conditions.

Canadian Natural would like to reiterate that ongoing gas samples are not practical, given the upper -- Kirby Upper Mannville wells are currently shut

in due to a GOB order and not connected to operating plants or facilities. So ongoing sample adds little actionable value above and beyond that provided by the four gas monitoring wells and ongoing SAGD monitoring. In Canadian Natural's view, its proposed monitoring condition should be evaluated to determine if there are reasonable circumstances, given the nature of the potential effects, and an evaluation of the associated costs and benefits.

ISH's requested suite of monitoring -- now, it has been modified, as we understand it, but generally exceeds the monetary risk of the unlikely impacts to the GOBed gas resource.

This morning Mr. Chodzicki on behalf of ISH confirmed that ISH's gas valuation assigns current value to Kirby Upper Mannville II pool gas volumes that are currently shut in under GOB where there is no current line of sight to gas volumes being allowed to produce.

Just to touch lightly on the solvent issue, Number 4, injected hydrocarbon is expected to stay within the near wellbore region -- you heard Mr. Ollenberger describe that as within 3 metres -- fully dissolvable in the bitumen and will be produced back in the very early stages of production. Controlled injection of relatively small amounts of

hydrocarbons for this start-up, which will be injected below the long-term MOP of 5,500 kPa, makes the risk to the overlying gas resource from this assisted start-up to be extremely low in Canadian's view.

We did hear ISH, I believe this morning, being agreeable to drop its requirement for the monitoring -- or the long-term monitoring of the solvent, so we appreciate that.

On thermal compatibility, Canadian Natural does believe it's in alignment with ISH for the well workover proposals, and as you heard from Mr. Thomsen, Canadian Natural will be cementing the McMurray formation in the 10-34 well.

So I'm going to turn briefly to Dr. Boone's report and then make some closing comments.

So Dr. Boone did provide an independent report, both an initial report with our hearing submission and then a supplemental report with Canadian Natural's reply submission that incorporated ISH's technical input. In his reports, Dr. Boone provided a comprehensive review of the parameters that should be considered when assessing steam containment. His assessment was that all the parameters -- you'll recall the table; I believe it's at Exhibit 50.003, page 9 -- as well as his oral testimony, but that they -- all the parameters are indicative of successful containment.

His conclusion related to Issue 1 was that the confinement strata at the KN08 and KN09 drainage boxes will act as an effective barrier overlying the bitumen-bearing McMurray formation consisting of a deposit or aggregation of strata that is not permeable to steam.

Dr. Boone also provided his technical analysis in his supplemental report showing that based on Dr. Chalaturnyk's laboratory tests of the Wab D mudstones from Suncor's MacKay site, the mudstones would be expected to behave in a ductile manner at the depths of the confinement strata for KN08 and KN09. A critical implication of this analysis is that any existing natural fractures or -- fractures or faults that might be induced by the SAGD operations would then be closed and sealed.

Dr. Chalaturnyk confirmed yesterday that his -- quote: (as read)

> His report shows that there was no permeability increase associated with the induced shear fractures in either the Wabiskaw or the Clearwater shales.

And that's found in the transcript page 173, line 17 to 20.

Now, Dr. Boone has used the risk assessment process to develop his recommendation for --

recommendations for Issues 2, 3, and 4. He concluded that the risks associated with each of these issues is low, and as a result, he recommended that no additional gas monitoring wells would be required or justified and that the temporary -- the proposed temporary MOP of 6,600 kPa should be allowed and, thirdly, that solvent injection during start-up should be allowed. And that's at Exhibit 50.003, pages 10, 11, and 12.

You've heard some discussion on the present value of the gas in the Wabiskaw B. Given the GOB decision, it's reasonable to assume that this gas will not be produced until SAGD operations in the area have ceased. It would also be reasonable -- this is Dr. Boone speaking. In his view, it would be reasonable to assume that only a fraction of the gas values should be impacted by any localized contamination that might possibly occur. Canadian Natural and ISH agree that the consequence of steam leakage is a financial only, not safety and not environmental risk. It is Canadian Natural's view that the maximal reasonable financial impact to ISH is less than $1 million.

With respect to additional monitoring, Dr. Boone's view is that it should be considered within this context. For an example, an additional monitoring well might cost a million dollars or more. This certainly cannot be justified, given that the risk is of similar

magnitude. One must also consider how much impact any monitoring is likely to have in reducing the risk.

ISH and Canadian Natural appear to agree that a monitoring well does not actually prevent the risk of gas contamination, rather, it only reduces the consequence if it enables operational changes that mitigate the consequence.

And, finally, with respect to the question of whether an additional DFIT should be required, Dr. Boone has also considered this within the risk assessment process. The real risk of a short duration of high-rate steam injection inducing a fracture that connects to the Wabiskaw B gas zone is very low. Canadian Natural -- I think I'm -- yeah. Sorry. I'm switching from Dr. Boone's comments in his report.

So this is Canadian Natural's view that really the question of an additional DFIT should be required -- that the real risk of a short duration of high-rate steam injection inducing a fracture that connects to the Wabiskaw B gas zone is very low, and, therefore, an additional DFIT is not required to manage this risk.

So I'm going to move to a few concluding remarks, and then I'm within reach of being done.

So SAGD operations have been occurring in the Fort McMurray area since 1996, 28 years ago, and since that time Canadian Natural has been a significant

contributor of SAGD development and they have drilled and operated 390-plus well pairs, all without any known incidents of lost steam to other formations during circulation, start-up, or continuous SAGD operations.

The KN08, 09 pads are part of the next development phase of the Kirby north project, and these pads are expected to recover between 30 and 35 million barrels. The project is an example of how bitumen development can create value for all Albertans through positive contributions to the local and regional economies during both construction and operations with direct, indirect, and induced employment. The successful execution of this project will also deliver up to $250 million in royalties.

Canadian Natural understands and respects ISH's concerns and has given ISH's assertions due consideration through the course of this proceeding. Canadian Natural remains of the view that its proposed mitigation measures and monitoring program are reasonable, given the nature of the potential effects.

We would encourage you to take a cost-benefit analysis in determining the appropriate mitigation measures and monitoring and that this cost-benefit analysis should consider the value of the remaining gas reserves. ISH provided evidence of the value of the gas remaining in the Kirby Upper Mannville II pool of

3.685 million. We're asking the Panel to keep the value of the gas in mind when it considers the monitoring recommendations that ISH has made.

Canadian Natural maintains that ISH's proposed mitigations and monitoring will add incremental costs payable by Canadian Natural, approximately 60 percent, and Albertans, 40 percent, and that that can be disproportionate to the value of the remaining recoverable gas and potentially would further delay the development schedule for KN08 and KN09.

With respect to ISH's request for a DFIT or a modern DFIT, as Dr. Chalaturnyk characterized it, in the drainage area of KN08 and KN09, Canadian Natural estimates that the cost of a new strat well, including the DFIT, to be $1.11 million. And that was noted in the table presented by Mr. Ollenberger.

Canadian Natural believes that if a modern DFIT is conditioned on -- if the approval is conditioned on a new DFIT test, it is likely that a new strat well will need to be drilled. Best practice entails that DFITs be conducted in vertical wells, and currently Canadian Natural has no vertical standing cased wells suitable for DFIT. All future strat wells, including the commitment -- or the committed -- commitment to gas monitoring on or in the vicinity of the KN09 drainage box, are planned as deviated wells, and therefore would

not be suitable candidates for a DFIT. A new vertical well would need to be planned, licenced, and drilled, which could potentially -- wouldn't be potentially executed -- sorry -- it could -- which could be executed at the earliest as part of the winter 2024/2025 drilling season.

With respect to scheduling, the KN08 and KN09 pads were originally scheduled to begin construction in January 2023. Subject to the decision of this proceeding and capital allocation, Canadian Natural is now scheduled to begin pad clearing in Q1 2025 following by drilling in Q1 2026. Pad facility construction is scheduled for completion in Q3 2026 with steam-in to follow.

Canadian Natural takes this opportunity to respectfully request that if the Panel is considering any monitoring requirements in the approval, that they -- that those requirements be conditioned so that they can be completed prior to steaming versus prior to pad clearing, and that will help avoid any further delay in the KN08/KN09 development schedule.

Having said that, it is Canadian Natural's view that its technical evidence and the commitments it has made to continue to enhance monitoring and controls demonstrate that the development and operation of KN08/KN09 will not impact the gas resource.

Canadian Natural reiterates its commitment, which is found in the materials, that in the highly unlikely event that the gas is contaminated from its operation, Canadian Natural could, at the time when the gas resource is allowed to be produced, assess connecting the gas to the SAGD infrastructure and burn the gas as fuel in the steam generators or pay reasonable compensation for the contamination. ISH would be fairly compensated for its share of the gas at that time.

For all of those reasons and more, Canadian Natural respectfully requests that the application be approved with its proposed monitoring conditions.

I'm going to take a moment and just make sure that we covered all the water. That was quite a bit of territory. Just give me a moment, please.

Okay. Any questions?

COMMISSIONER CHIASSON: No. Actually, we have no questions for you.

J. JAMIESON: Thank you very much. I thank you for your patience. That got a little clunky at the beginning. I apologize. Just given the time constraint, we were still trying to get accurate exhibit numbers, and obviously that showed. So thank you for your patience, and those are all our comments.

COMMISSIONER CHIASSON: Yes. Yeah. No. And I would

say the Panel appreciates that you built in those references. It does make our life easier in the long run.

J. JAMIESON: Okay. Wonderful. Thank you very much.

COMMISSIONER CHIASSON: And, Ms. Riley, now we're looking at five-minutes, break, or ...

M. RILEY: Yes. I would probably need five minutes. I do note that we've been going for about an hour and a half, so I don't know if anyone else needs a bit of a longer break.

COMMISSIONER CHIASSON: Well, I think we have the space. You know, let's take -- let's take 15 and come back -- let's plan to come back at 3:40.

M. RILEY: Thank you.

COMMISSIONER CHIASSON: And that way that gives everyone the chance for a pause. So thank you.

(ADJOURNMENT)

COMMISSIONER CHIASSON: All right. Thank you. So, Ms. Riley, we'll turn it over to you now.

Final Submissions by M. Riley

M. RILEY: Thank you very much. I see that I have an entire hour allocated to me to speak, but I have recently received some good advice that I'm going to heed, and that is, be brief, be bright, and be gone.

As this proceeding draws to a close, ISH wishes to reiterate its steadfast commitment to the responsible development and conservation of Alberta's natural resources. ISH's objections to CNRL's application are grounded in its deep commitment to responsible development in the public interest, risk to the integrity of ISH's current operations and potential adverse effects on ISH's overlying gas interests.

Despite acknowledging that geologic interpretation requires a suite of information, when CNRL engaged with ISH, CNRL refused to share pertinent information. CNRL's evidence was that it did not want to participate in this hearing, which is entirely inconsistent with their refusal to sensibly engage with ISH. From CNRL's first engagement with ISH about this application, ISH has demonstrated a preference to avoid undue expense for both parties and for Albertans generally. ISH has done so by seeking resolution of its concerns through alternative dispute resolution mechanisms, which CNRL declined, favouring instead to proceed with regulatory intervention. This action, coupled with CNRL's insistence on a confidentiality order that seems more procedural than necessary, underscores a reluctance to engage in open constructive dialogue aimed at finding compromise while protecting the public interest.

ISH's submissions has detailed the geological and

operational risk associated with CNRL's proposed development, particularly highlighting the absence of effective barriers to prevent the migration of steam, fluid, and reaction products. These technical analyses underscore the significant concerns regarding the proposed development's impact on the integrity of adjacent resources.

Furthermore, CNRL's approach to managing these risks, including its handling of seismic data and no technical -- no apparent technical basis for its request that long-term maximum operating pressures reveal a disconcerting gap in the robustness of the risk management strategies. ISH's application for an adjournment based on the need to review the synthesis of evidence that had taken two weeks for CNRL to prepare and which was delivered minutes before start of this hearing is a testament to ISH's diligence in ensuring that all potential impacts were thoroughly understood and appropriately addressed.

With respect to the closing remarks of Ms. Jamieson, we would ask the Panel to carefully review the transcript with respect to the evidence given by Dr. Chalaturnyk and Mr. Vickerman. While it is possible that we may have misunderstood Ms. Jamieson's remark, ISH believes that Ms. Jamieson may have misquoted ISH's evidence.

The AER is mandated to ensure the safe, efficient, orderly, and environmentally responsible development of resources over the entire life cycle. CNRL seeks approval to amend Commercial Scheme Approval Number 11475 for the recovery of crude bitumen from the McMurray bitumen zone. ISH and CNRL agrees that any approval issued in the public interest must be consistent with the purpose of both the Oil Sands Conservation Act as well as the Oil and Gas Conservation Act.

Any approval issued must therefore, one, affect the conservation of and the prevention of waste of oil and gas resources of Alberta. It must provide for the economic, orderly, efficient, and responsible development in the public interest. It must provide for the responsible management of a well facility, well site, or facility site throughout its life cycle. It must afford each owner the opportunity of obtaining the owner's share of the production of oil or gas from any pool, and it must control pollution above or at or below the surface in the drilling of wells and in operations.

CNRL and ISH agrees that the gas over bitumen, or GOB, decisions do not specifically address wastage. This is because wastage was never the intent or underlying premise or a necessary implication of the

GOB decisions. Some of the premises of the GOB decisions were that associated gas production could have a detrimental effect on steam-assisted gravity drainage performance. The extent of the effect would depend on the specific reservoir situation, economic circumstances, and operating strategy. And that thermal bitumen processes could have a detrimental effect on associated gas recovery, but such effects were expected to be relatively minor.

ISH and CNRL further agree that while the Court of Appeal of Alberta's decision in the matter of Alberta Energy Company v. Goodwell is authority for the proposition that some wastage may occur during responsible development, it does not amount to a justification for failure to take reasonable measures to avoid wastage.

ISH struggles to understand CNRL's comment in its closing remarks regarding the GOB shut-in order. On the one hand, CNRL suggests that gas depletion would impact its production, but on the other suggests that the Wabiskaw C is an effective seal based on the data acquired after the 2005 SSG study. This data does not form part of the record.

In its arguments, CNRL proposes that this Panel proceeds as the Panel for KN06 did. ISH would comment that this is a different matter with different hearing

issues and different concerns.

In its evidence, CNRL expressed the view that the conclusions drawn in the AER's January 2021 decision regarding the KN06 drainage box should continue to find application in this hearing. CNRL specifically relies on the conclusions in the KN06 decision regarding what measures would be reasonable to avoid or mitigate potential impacts as well as what is in the public interest. In its reply evidence, CNRL, however, acknowledged that there are differences in the geological strata present at the KN08 and KN09 area versus the KN06 box and that those differences are relevant to this proceeding.

CNRL also state and, as reiterated under cross-examination, that it does not intend to damage or waste the gas resource. It therefore follows that the parties agree that reasonable steps ought to be taken to ensure that any approved production occur under conditions that reflect the intent of the legislation and the bodies.

At the outset of this hearing, ISH made the point that all of the relevant evidence is not filed. The Panel correctly found that this is an application, not an appeal, and that it has to determine whether or not to allow the development in the public interest. At the time that CNRL submitted their application,

March 11, 2022, the May 13 edition of Draft Directive 23 applied to the application.

Pursuant to Section 7 of the draft directive, all geological maps submitted are required to incorporate available well information and seismic data and be annotated with posted well data values. As appeared from the evidence the KN24 and 25 drainage boxes were not met. Section 7.10 also mandates that in situ operations be conducted in a manner that ensures reservoir fluid containment. The directive does not say that applicants are required to use reasonable commercial efforts to ensure containment. This is, then, clearly not only an economic issue but a regulatory requirement.

Section 7.10(7) further requires applicants to specify their requested MOP and discuss how it was determined and why it was appropriate. CNRL did specify its requested MOP in its application, but that has evolved over time, and CNRL's final request remains unclear. In any event, CNRL has admitted that with respect to their requested reduction, there isn't really a solid technical justification.

The last point under the regulations, Section 7.10(8) of the draft directive requires in situations where geological modelling was conducted that the model's input files be filed. CNRL has not

provided the input files nor were assumptions in the model adequately discussed.

In its evidence, CNRL acknowledged that the only information relevant to the modelling was contained in the modelling report. This report did not include the input files nor any information regarding deformation. ISH was unable to review and consider the model, interpret the assumptions, test the validity of the model because CNRL declined to provide a copy, and this despite the clear requirements under the directive.

CNRL's application has been incomplete from the outset. Although it was initially filed on March 10, 2022, it was not until eight months later that CNRL had finally rectified the deficiencies identified by the AER in a series of three SIRs. Even in the time since ISH's application to participate was granted, CNRL has continued to develop its application materials. This is evidenced not only in the deficiencies identified by the AER, but also in CNRL's request to postpone its initial submission in order to take into account new cores and image logs.

In addition to the further revisions to CNRL's application, it became apparent through the course of this proceeding that CNRL has had information on hand that would have helped ISH in assessing the application and which would have helped the AER in its decision

that it has not provided. Specifically, with respect to GCMS data, CNRL has said that they have several reports from Schlumberger. They have not been filed, but what we do have is that -- their interpretation.

On the modelling, I believe the quote is -- or the question was: In your opinion, if there was thermal expansion in the Wabiskaw D, what kind of pressure could that generate? And the answer was: We have not included a prediction or a model of this within the record to bring up.

Regarding the image logs, the request was for image logs, and the response was: You don't need image logs because you can do a comprehensive interpretation without them.

CNRL further says that it has reviewed all of its core and all of its image logs data and could not identify any fractures. The question is: Did you look at all the information that you did not file? And the answer was: Yes. We could not verify any of that.

Another issue is the DLIS files. CNRL's evidence was you require the DLIS files to do a proper job. We still have not seen those.

Mr. Vickerman was clear that the information on the record is insufficient to draw final conclusions regarding faults and fractures in the confinement strata. CNRL -- and this is the point of all this

history -- has had two years to do a further DFIT to provide further information. If the AER now says that they should file a further DFIT, they can only complain about a delay that is caused by that. They've had two years to do it. If they have not done so, they are the authors of their own misfortune.

To be clear, ISH has not and does not seek an order preventing CNRL from developing the bitumen resources. ISH does not specifically advocate for a decision one way or another. It is for the AER to decide whether the development proposed by CNRL complies with the regulatory requirements and if it is ultimately in the public interest.

What ISH is asking is that the AER, if it is satisfied that the application ought to be approved, recognize in the conditions of approval that there is unique geology underlying KN08 and KN09 and include appropriate measures to mitigate any resulting risk.

I will next address the conditions of approval, including monitoring conditions that ISH requests. I will first provide a summary list and thereafter address the evidence underlying each of the conditions proposed.

ISH submits that the following conditions of approval must be imposed: One, a diagnostic fracture injection test, or DFIT, in an appropriate area

relative to the KN08 and KN09 drainage boxes must be conducted and the results of that test should be shared with ISH and the AER prior to steaming and the results from the DFIT must also be used to determine the long-term maximum operating pressure.

Two, CNRL's undertaking to pay for the cleaning of contaminated gas; alternatively, to compensate ISH for the value of what ISH contends should be sweet natural gas. In the event of contamination, should be noted, together with the AER's expectation, that CNRL will honour its undertaking as a condition of approval.

Finally, the following monitoring conditions should be imposed. A minimum of one observation or gas monitoring well per pad instrumented with piezometers cemented on the outside of casing and multipoint thermocouples inside or outside the casing completion that will monitor the Wabiskaw B gas, the Clearwater caprock, the Wabiskaw D, and the McMurray formations. Surface gauges should be installed around all monitoring wells to help verify downhole pressure information.

A Wabiskaw B gas sample should be collected directly above the KN08 or KN09 drainage boxes and develop a compositional baseline pre-SAGD operation start-up at KN08 and KN09.

Next, gas samples should be collected post-SAGD

operation start-up and over the life of the project of KN08 and KN09.

And, finally, gas samples should be compared between the baseline and new data to evaluate and detect any compositional anomalies that may be indicative of contamination.

I will then speak on the DFIT. Canadian Natural argues that DFIT data tends to be regional, that they have drilled hundreds of wells, and that their assumptions in the modelling was conservative.

CNRL, however, agreed that deformation data produced by the modelling was not included in the record. If regard is had to Figure 7 at Exhibit 46.02 at PDF page 46, the stress gradient over the confinement strata is, in fact, not conservative but average. And even if it was conservative, the homogenous model cannot predict with any acceptable certainty how the heterogenous underlying strata will behave.

CNRL is at pains to point out that the modelling does not indicate that there is any concerns regarding stress in the McMurray and Clearwater formations. ISH does not take issue with that, but that is not what this hearing is about. Deformation information is not part of the record, and that is what we were keenly interested in.

There is a different of -- difference of opinion regarding brittle and ductile behaviour of the rock. This is key to determine the impact on fractures within and deformation of the confinement strata during SAGD operations. CNRL did not provide laboratory tests specific to KN08 and KN09 to determine the behaviour of the rock. In the absence of these, there is uncertainty in the quantification of brittle or ductile transition behaviour for the fine-grained zones within the confinement strata.

CNRL took issue with Dr. Chalaturnyk's McKay or MacKay River project example. CNRL cannot sit on both chairs. Either the example does not find application or it is proof that the Wabiskaw D could hold back steam in general. It cannot be both. It is either region-specific and then does not apply, or we have confirmation that we have brittle strata.

The parties have agree that there are differences in the geology underlying KN08 and KN09, especially when compared to the geology to the east of KN08 and KN09. CNRL's experience in other areas of Kirby north is therefore not determinative of local conditions.

If we look at the current DFITs available and we compare the stratigraphy of the areas where we have current DFIT data with the stratigraphy of KN08 and KN09 as interpreted by CNRL, the following is readily

apparent. The A2 mudstone is present across all the wells of the -- analyzed in the current DFIT data but is notably absent in two of the wells that form part of the KN08 and KN09 stratigraphy. It is further common cause between the parties that the A2 mudstone is absent over a large part of the KN08 and KN09 drainage boxes.

The mid-B mudstone is present with a fairly uniform isopach across all the wells analyzed in the current DFIT data stratigraphy, but the isopach in the wells analyzed over KN08 and KN09 varies significantly.

It is also now common cause between the parties that the mid-B1 mudstone is, in fact, not present over the entire drainage area.

As assessed by CNRL, the value with conducting DFIT is to determine principal in situ stress that can be used for either leveraging some geomechanical effects for a resource recovery process or for caprock integrity and confinement strata integrity. To be clear, ISH's concern is about the failure of the confinement strata layers that would allow for upward migration of fluids.

CNRL decided to not acquire any new DFIT despite the fact that they have drilled many more wells since 2021 and argues that the acquisition of a new DFIT with costs ranging from $375,000 would be unduly punitive.

The 9-6 DFIT performed in 2012, which was referred to by CNRL, is the closest data point to KN08 and KN09 but is still located several kilometres away. The results from that test were rejected.

The other DFITs available to CNRL are located very far from the zone of interest and were primarily acquired to analyze the caprock integrity, which is not the topic here. Given that CNRL only acquires must-do DFIT, if this data was initially required and the acquisition failed, ISH wonders why this acquisition was not attempted again.

This data point shows a lower initial stress data, possibly indicating that this stress regime may not be regional. ISH sustains that the initial stressor on KN08 and KN09 is not -- does not conform to the eastern area where the DFIT is required as the geology is significantly different.

The DFIT requested by ISH is aimed at providing information relative to the confinement strata, and new DFIT will allow CNRL to calibrate the minimum stress value in the area of KN08 and KN09. If the newly acquired minimum stress value is lower than CNRL estimated, the risk for the confinement strata to fail is higher.

ISH commented that the 2D geomechanical model presented by CNRL is not appropriate to represent the

3D dimension of the heterogeneities of the zone of interest, though it is adequate for caprock integrity. CNRL disclosed, during cross-examination, that they're currently developing a 3D geomechanical model, which is still very preliminary, to validate any geomechanical model confirmation of the in situ stress regime and the starting point of the minimum stress path followed under SAGD operations is required to get certainty on the end point of the modelling. If we do not know where we start, we do not know where we will end up.

In addition, there were no samples from the confinement strata in KN08 and KN09 tested in the laboratory to support the model inputs.

During its direct evidence, CNRL reported that the 2D geomechanical model showed uplift of confinement strata. They also added that the uplift or deformations -- the vertical deformations are not shown in the report, just summary plots of the stress levels which are a result of that deformation. It is not clear why CNRL did not include their full interpretation as part of the geomechanical model.

Finally, CNRL does not agree to take another DFIT. Their reluctance is related to findings related to a -- to a new data point and that it may amend the requested MOP, which would naturally reopen the regulatory process.

Further, CNRL takes the view that irrespective of the results of a DFIT, even if there was the unlikely result of having a reduced stress, it would have no effect on their request for a temporary MOP of 6,600 kPa. ISH believes that this is in the public interest, to acquire the additional DFIT, given the large uncertainties regarding the geology, the absence of well control, and the distance to the next DFIT data point. The acquisition of a new DFIT should be requested before any SAGD wells are drilled.

It is impossible to determine from the geomechanical model if the revised MOP of 5,500 kPa is safe, especially given the fact that the model was designed to test circumstances at 4,000 kPa. The model does not, in fact, answer any of the hearing questions.

I will then move on to the second of the conditions that ISH proposes, and that is the undertaking to pay for the gas. In its reply evidence, CNRL reiterated its commitment that in the event that the gas is contaminated from its operations and cleaning of the gas was determined to be cost-prohibitive, it would compensate ISH fairly for its share of the gas. This undertaking is not clear. Will ISH be compensated for sweet natural gas or sour gas? The request that it -- this determination only be made after SAGD operations have been completed and the

GOB wells can be opened also raises the question of how CNRL would be applying the gas or using it in its own operations, given that the -- the GOB gas cannot be reopened before the SAGD operations are complete.

I will now turn to the monitoring conditions. The first is the request for observation or gas monitoring wells. There are a few points. The first is during the cross-examination CNRL raised the concern that scale plugging inside a well could take place independently of the MOP. This raises the question of whether CNRL is really able to monitor any exceedance to the MOP and if another pressure event could even be undetected if the well is plugged.

In its reply evidence, CNRL indicated that it was prepared to accept and modify its risk mitigation measures to include the conversion of the 10-34 well into an additional monitoring well, to convert the 1-3 well from a standing cased well to a Kirby Upper Mannville II pool gas monitoring well prior to steaming of KN08 and KN09, to maintain its existing gas monitoring from the 10-1 well, and CNRL has also indicated that it plans to drill a stratigraphic evaluation well in the immediate vicinity of the KN09 development and expects that one location could be utilized as a gas monitoring well prior to the commencement of steaming operations.

Given the lack of well control around KN09, the heterogeneity of the geology and its lack of continuous barriers between the SAGD McMurray zone and the Wabiskaw B zone, ISH requests that a gas monitoring well be drilled on KN09.

The BHI or FMI as submitted does not enable either ISH or the AER to verify the extent of fracturing. CNRL conceded during cross-examination that the digital data of the FMI logs, or DLIS, is required for any interpreter to deliberate professional work and, while available to CNRL, was not provided.

CNRL showed various scores showing the range of facies highlighting the heterogeneity of the confinement strata in those drainage boxes, specifically in terms of thickness across the area.

Regarding the regional extent of the confinement strata, just a few comments. Again, there is a notable lack of well control over the KN09 drainage box. CNRL said that they were using the barriers or baffles identified by GCMS as a proxy for what SAGD operations will do. CNRL, however, modified the Fustic paper methodology to introduce their own methodology, which was not peer-reviewed. The modification is significant, as, in CNRL's opinion, a forward-stepping increase in concentration with decreasing depth is also a sign for a barrier. ISH and CNRL both agree that

GCMS data is one-dimensional and cannot provide any information on the lateral continuity of a barrier. ISH's opinion is that there is one barrier in each well but not in the same strata, suggesting that the strata are not continuous.

I will next turn to the issue of conductive heating. CNRL and ISH agree that conductive heating is inevitable. During cross-examination, CNRL quoted the temperature diffusion factor. Thermal conductivity, thermal diffusivity, and specific heat capacity define a material's ability to store and transfer heat. No data is provided in records on any of these factors. Despite a major event at Cenovus in 2013, no studies were done on conductive heating, the pace and impact on overlying strata.

CNRL's evidence was that 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 KN08 and KN09, we have perhaps 10 to 12 metres, so there is going to be less heating or much slower heating than at Cenovus. This is not consistent with the confinement strata as defined by CNRL as 3.8 metres to 14.3 metres at the maximum. This includes the Wabiskaw D upper and Wabiskaw C, both located above Wabiskaw D bitumen.

Total thickness of the layers between the top of

the SAGD reservoir and Wabiskaw D bitumen ranges from 10 metres to 12 metres. CNRL pointed to the PNX log on Well 6-04 indicating temperature progression above the top of the reservoir towards the Wabiskaw D bitumen and showing that temperature reached 60 degrees at 50 metres after four years. Wabiskaw D bitumen could surely start to expand at this temperature and should start to immobilize at 80 degrees Celsius. How hot will it be after ten years of SAGD operations? How long will it take to reach 150 degrees Celsius? Despite CNRL claiming that they operate more than 140 SAGD well pairs and they run PNX on an annual or biannual basis, this is the only PNX log provided by CNRL.

CNRL cited that Wabiskaw D production after it -- it's mobilized by conductive heating is highly unlikely. We question whether an overpressure event like the one observed at Christina Lake would occur at KN09 and -- KN08 and KN09.

During cross-examination, Dr. Boone also stated that once the steam hits the top of the reservoir, it's there for ten years and conduction continues to occur, and any bitumen up there is mobilized when it is heated. The good thing is that you get a little bit more oil out of that. The application does not allow for production of Wabiskaw D, even as a consequence of

approved production.

Note that CNRL chose not to communicate about the existence of two pads, KN24 and KN25, that are already approved by the AER. They're adjacent to KN09 to the north and dedicated to Wabiskaw D production.

The overpressure event observed in 2013 at Cenovus's Christina Lake pad more than 11 years ago is well documented. The event should have been considered by CNRL and the risk analysis for this application, given that the stratigraphy between the KNIDA is virtually identical to that in the Christina Lake example. The KN08/09 pads are placed in the same valley as the Kirby north IDA and also contain very similar confinement strata units. The impact is high, as it required Cenovus to drill several wells to mitigate the overpressure and continues to be monitored and remediated today.

CNRL confirmed that they 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. Dr. Boone said he did not include this in his risk assessment. ISH is concerned that CNRL did not consider the risks associated with an overpressure event created by conductive heating.

I will now make a few brief comments on the confinement strata. The first is the A2 mudstone. The

parties are in agreement that the A2 mudstone is absent over the majority of KN09 and -- KN08 and KN09. On the Wabiskaw C, CNRL asserts that the Wabiskaw C is a continuous seal, contrary to the SSG evaluation done at the time of the GOB shut-in order but provide no data to support their point. This is the only strata that is continuously present across the KN08 and KN09 drainage boxes.

Regarding the mid-B1 mudstone, it is apparent that ISH and Canadian Natural disagree on the lateral extent of the mid-B1 mudstone. A map of the areas where ISH and CNRL each plot the absence of the mid-B1 mudstone appears in the record at Exhibit 50.003, PDF page 50.

During cross-examination, CNRL conceded that there are some differences in the lithologies expressed in the underlying lower B1 regional sequence, the overlying upper B1 sequence, and that those differences can cause some difficulties in interpreting -- oh, interpretation, I suppose -- and that mid-B1 mudstone has a variable character. And that is because the mid-B1 mudstone doesn't have a direct seismic indicator. It is apparently obvious that it is -- its existence is extrapolated through regions where we do not have well control as well.

In their reply submission, CNRL conceded in -- the absence of the mid-B1 mudstone in the 1-3 well and

acknowledged that the core in well 9-3 that would supposedly have contained the mid-B1 mudstone was lost.

In its argument, CNRL says that Mr. Barrie conceded that there was mid-B1 mudstone within his blue line polygon. Mr. Barrie, in fact, said that if it would move the cross-examination along, he would agree. He also indicated that it was difficult for him to examine.

I will now speak to the surface gauges. The parties agree that there is a declining pressure in the 10-1 well and that the cause is unknown. Parties also agree that data from earlier variations could not be verified. Surface gauges would have at least confirmed that what we saw was accurate. The costs attached to these surface gauges are inconsequential.

Regarding the collection of a sample, it seems that the parties have agreement that a pre-production of the -- or at least a pre-SAGD operation compositional baseline should be collected. The parties also seem to agree that once the SAGD operations are completed and the GOB gas could be produced, there should be another sample. The question is whether there is any necessity for further sampling across the lifetime.

Having only two points in time for the gas sample is inadequate, in ISH's view, to ensure the protection

of the gas resource. In any event, if this GOB order is lifted before SAGD operations have been exhausted at KN08 and KN09, the only way to determine the effects of CNRL's operations would be to complete a sample before SAGD operations have concluded in any event.

CNRL takes the view that such gas sampling would be uneconomical when compared to the value of the gas resource. ISH disagrees with this discount methodology applied by CNRL. It is CNRL, however, who wishes to develop the bitumen, potentially to the detriment of ISH's gas interest. The protection of ISH's gas interest and CNRL's obligations under Directive 23 to ensure reservoir containment suggest that appropriate -- an appropriate metric for determining the economy of conducting gas sampling should be derived from the anticipated cost of constructing the well pads.

On the last condition, and that is the comparison of the -- of the sample results, it seems that the parties are in agreement. ISH acknowledges that CNRL has experience with the developments in the Kirby north area, but the evidence of this week showed that the geology underlying KN08 and KN09 differs from other areas in Kirby north. CNRL admitted under cross-examination that it's primarily driven by a profit motive and they do what is right for them. That

is, "doing it right" according to their mission statement.

Part of the reason that CNRL gave for its initial extension request was the need to retain a third-party expert. But under cross-examination, Dr. Boone admitted that he has not been retained by anyone other than CNRL over the past year. Dr. Boone opined on Issues 1 to 4 in this hearing and drew conclusions on matters that are outside of his area of expertise. ISH submits that the evidence advanced by CNRL should be given little weight, both as a result of the partisan nature of its witnesses and also because CNRL's evidence has materially changed in response to ISH's submissions.

With the limited evidence that CNRL has provided, ISH has shown there are significant uncertainties concerning the effects of CNRL's planned development. ISH submits that this Panel is ultimately tasked with doing what is right for Albertans. In other words, the Panel should only approve this application if it is in the public interest. CNRL has told us what is in its interest and suggests that the Regulator should approve its application, taking the view that ISH's statement of concern was unjustified. This despite the fact that CNRL has provided no technical basis for reduced MOP and despite the fact that CNRL has refused to provide

ISH and the Regulator with sufficient information to reasonably evaluate CNRL's application.

Ultimately, ISH wishes to protect its gas resource. The imposition of conditions proposed by ISH will ensure that the gas resource, which is owned by Alberta, is not wasted. ISH presented a diverse panel consisting of industry experts qualified to review and assess the hearing issues. ISH's expert panel leveraged their broad and diverse experience to deliver an objective analysis. A subset of the monitoring proposed by ISH as well as its geologic interpretation has also -- has already been incorporated by CNRL, proving that the opinion presented by ISH is relevant and accurate.

In conclusion, ISH would request the Hearing Panel to include its proposed conditions of approval in the conditions, should it decide to approve the application. Those are my submissions.

COMMISSIONER CHIASSON: Thank you, Ms. Riley.

I do have one question for you. So if I understand correctly, part of what you indicated in ISH's proposed conditions is that this Hearing Panel take -- essentially take CNRL's undertaking in relation to compensating ISH if there is contamination to the gas resource and embody that as a condition to the approval. Am I understanding you correctly there?

M. RILEY: It is more the AER's expectation that CNRL will honour its obligation to be included as a condition of approval.

COMMISSIONER CHIASSON: Okay. And can you, I guess, point the Panel to where we have -- where our authority would flow from to impose such a condition.

M. RILEY: I think it is part of your overarching authority to make any condition in the public interest. The reason ISH includes this request is because in previous applications, similar types of conditions or undertakings have been made, and when it came time to enforce those, the attitude was, Well, it was not a condition of approval and therefore not binding. If it is a factor that the Panel will take into account in coming to its conclusion, we would submit that it should be included as -- as part of the conditions.

COMMISSIONER CHIASSON: Okay. Thank you. I appreciate your answer.

Ms. Jamieson, it looks like you would like to add something for our consideration in on my question.

J. JAMIESON: Yeah. May I?

I'm familiar with the AER's practice to just, you know, articulate an expectation that any commitments that a company makes be honoured, so just that general type of language. I'm not familiar with this type of

commitment being actually baked in or made into a condition of the approval. So I'll leave that with you, but that would be unusual, in my experience. Thank you.

COMMISSIONER CHIASSON: Thank you. We appreciate your input.

So I think that brings us to the end of -- end of this hearing. So, parties, thank you very much for your participation. On behalf of the Panel, I would like to say that we appreciate the efforts of counsel and witnesses through what was a very full week, and we thank you all for your respect, your civility, your patience, and your good humour, and I'm sure we'll all think of broccoli in new ways coming out of the -- coming out of this hearing.

The Panel would also like to take the opportunity to publicly give thanks to the AER staff who supported this hearing, including Mr. Lung and the rest of the hearing services team, our subject matter expert team who helped us through this vast range of very technical information, and our counsel, Mr. McClary and Ms. Peddlesden. Thank you all so much for your support on this process.

So going forward, as the Hearing Panel, we will review the evidence and the submissions, and we will issue our decision on Canadian Natural's amendment

application. We will issue a written decision within 90 days of the close of this hearing, so the clock starts sticking. Tomorrow is Day 1.

Each of the parties who have participated in this hearing will receive a copy, and the decision will also be posted on the AER website. And so this hearing is now closed.

For anyone who has to travel beyond the Calgary area, I wish you safe travels, and thank you all very much.

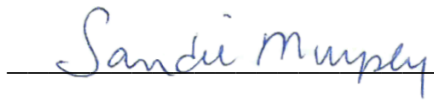
And the one -- the one thing I forgot to mention, which I should not, was thank you so much to our court reporters for the magnificent job they've done all week.

PROCEEDINGS CONCLUDED

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 9th day of February 2018.



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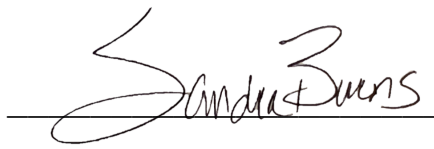

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