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IN THE MATTER OF
Regulatory Appeal 1927181
to the Alberta Energy Regulator

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TABLE OF CONTENTS

Description		Page
October 15, 2020	Morning Session	332
Discussion		332
Ms. Berg Cross-examines Canadian Natural Resources Limited		333
Alberta Energy Regulator Staff Questions Canadian Natural Resources Limited		368
Alberta Energy Regulator Panel Questions Canadian Natural Resources Limited		386
October 15, 2020	Afternoon Session	410
Response to Undertaking by Canadian Natural Resources Limited		410
Alberta Energy Regulator Panel Questions Canadian Natural Resources Limited		413
VERONIQUE GIRY, PETER VERMEULEN, DAVID LEECH, EDWARD MATHISON, EARL WARD, BRETT THOMPSON, JENNIFER CLEE, Affirmed		419
Rebuttal Evidence of ISH Energy Ltd.		419
Ms. Jamieson Cross-examines Canadian Natural Resources Limited (Rebuttal)		445
Alberta Energy Regulator Staff Questions ISH Energy Ltd. (Rebuttal)		457

Certificate of Transcript	466

Proceedings taken Via Remote Video

October 15, 2020 Morning Session

C. Low	The Chair
C. McKinnon	Hearing Commissioner
B. Zaitlin	Hearing Commissioner
S. Poitras	AER Counsel
A. Hall	AER Counsel
D. Campbell	AER Staff
S. Botterill	AER Staff
L. Chen	AER Staff
E. Galloway	AER Staff
S. Harbidge	AER Staff
T. Rempfer	AER Staff
T. Turner	AER Staff
A. Shukalkina	AER Staff
T. Wheaton	AER Staff
L. Berg	For ISH Energy Ltd.
S. Hryciw	
J. Jamieson	For Canadian Natural Resources Limited

A. Vidal, CSR(A)	Official Court Reporter
S. Howden, CSR(A)	Official Court Reporter

(PROCEEDINGS COMMENCED AT 9:00 AM)

Discussion

THE CHAIR: Just before we go back to ISH's continued questioning of the Canadian Natural panel, I just wanted to let you know we've revised, as you know, the schedule, and for your planning purposes, at sort of a high, high level, what it looks like is finishing with the Canadian Natural witness panel this morning. So ISH will finish their questioning. AER staff and then the Panel, if we have questions, any redirect by Canadian Natural, and then we'll take -- and probably fit a shorter break in there and then take the longer lunch break, and then after the lunch break, we would then have ISH rebuttal evidence, if any, and then with the usual round of questioning.

So with that, I guess, Mr. Iannattone, since you are the chair of the ISH -- or, sorry, the Canadian Natural -- pardon me -- witness panel, have you got everybody present and accounted for? It looks like it to me.

MR. IANNATTONE: I do, Madam Chair.

I would like to make a request before we start with the cross-examining. Yesterday, before the break, there was a question that was asked to CNRL. It was about Table 4-1 in 65.01, and during the break, we were to come back with an answer to that question, and we -- we did not answer that question, so I wonder if it's appropriate to answer that question now.
THE CHAIR: That would make sense to me, but let's -- it was in response to a question from ISH, I believe?
MS. BERG: It was. And -- and that would be appreciated. Why don't we just start with that?
Ms. Berg Cross-examines Canadian Natural Resources Limited
MR. IANNATTONE: Okay. Mr. Lavigne, please.
MR. LAVIGNE: Good morning. Would we like to bring that exhibit up while we discuss it?
MR. IANNATTONE: It's page 13 of 45, 65.01.
MS. TURNER: One moment.
MR. LAVIGNE: I believe it's page 13 in that document.
Ms. Berg, would you like to repeat the question?
Q MS. BERG: I believe the question -- and I don't have it in front of me, but it was regarding the number of wells or number of core that were pulled from the KN06 box for this particular table, if

recollection serves.
A MR. LAVIGNE: Okay. Thanks.
For -- yeah. So for clarification, yeah, the question I had is: How many cores for this table are from KN06, I believe?
Q Okay. Yeah.
A Yeah. So I apologize. I was confused. I was speaking to the mapping area that Canadian Natural submitted, which is larger than the KN06 box, so -- but to answer your question specifically, there are 12 wells in the KN06 box. 8 of them have core, 11 of them have image logs, and 7 wells were used to calculate the averages for the values in the table.
Q Okay. Thank you.
All right. I will begin, then, my next series of questions, and I -- the initial questions I'm not sure who -- who will be responding from CNRL.
And so, Mr. Iannattone, I'll -- I'll direct them to you, and -- and you can direct them to your team accordingly. So I'd like --
A MR. IANNATTONE: Sounds good.
Q So I'd like to begin with some questions regarding the 10-01 well. If we could go to Exhibit 201, page 204, please.
MR. IANNATTONE: Mr. Craig, please.
MS. BERG: And it'll be on the bottom of

the page for the hearing coordinator. Again, that's 201, PDF 204.
MS. TURNER: It's coming.
MS. BERG: Yeah. No worries. First document today, so ...
And if we could just -- oh, sorry. If we could just go to the bottom of the page, the last paragraph.
Q MS. BERG: So you'll see there that it states: (as read)

> Further, a well located at the 10-01 contains monitoring for thermal compatibility purposes. The data collected to date supports no evidence that the shale barrier between the McMurray reservoir and the overlying gas-over-bitumen zone has been impacted. Observation data has been and will continue to be provided to ISH from this well.

So my question is: What kind of data interpretation was conducted in October 2019?
A MR. CRAIG: At that point in time, we would've had the recollection. We have the pressure and temperature trends that we would've started collecting in about March of 2019 until that time frame, and that would've been the data that was supplied to ISH.

Q What is exactly CNRL's interpretation process when -- when it collects that data?
A So we are analyzing that data for any anomalous trends. I would -- I would point us towards the submission that -- it's tab -- sorry. I'll just find it here in my records if we want to bring that up. There is the --
Q I could actually just go on to my next question if --
A Sure, sure. I was going to try and refer to a tab that CNRL had submitted that had a -- the pressure trends and then a -- a table of our interpretation at the time, and I believe that would answer the question.
At the time of --
Q Okay.
A -- August of 2019, our interpretation was that there was no integrity concerns at the 10-01 wellbore.
Q Okay. And, sorry, that is on the record, then?
A It's on page 49 of 1066, so I believe that's the CNRL submission, and that is exhibit number -- CNRL Submission 30-02.
Q Sorry. Is that "30 dash" -- if it's 1066, I think that might be 48 -- 48.02.
A Thank you for that.
Q Yeah. All right. Thank you.
How regular is your review process?
A We look at these wells on a monthly basis.

Q Okay. Thank you.
A So we collect the data, and it's available to us daily --
Q Yeah.
A -- coming to our data-collection system. We have access to the data daily. We have a formal review monthly.
Q Okay. Thank you.
If you could please go to Exhibit 48.02, PDF 48. And that's perfect. It's the upper one that I'll be referring to.
So Figure 1 shows the 10-01 pressure and temperature history from March 2019 to July 2020 with significant events highlighted with red lines. The green temperature drops significantly in November 2019; correct?
A Yes.
Q Why would CNRL not flag that temperature drop as a significant event?
A It was -- we're looking at responses that are related to the SAGD operation right now, currently, in nearby KN06, a couple hundred metres away, and we would see anomalous issues with temperature increases. So an issue with well integrity in this well may be indicated by a temperature increase. A temperature decrease is not a concern.

Q All right. One moment, please.
What is your explanation of that temperature drop?
A Well, I believe that Mr. Leech's report submitted by ISH would indicate that's a Joule-Thomson effect with gas flow in the wellbore.
Q Okay. Thank you.
If I could get you to go -- happily, we're in the same exhibit, PDF 602. So that's just the first page of the CNRL Directive 54 presentation. The annual report presented to the AER was in September 2019, and my understanding is there's no recent 2020 D54 report available for Kirby; correct?
A That's correct, as I understand.
Q In this Directive 54 presentation, there's no mention of the Kirby North 10-01 monitoring data. Can you advise as to why?
A I would -- I believe -- I'm not exactly familiar with the requirements of D54, but I believe we submitted all SAGD observational data within D54. We -- I'm not sure if there's a requirement within D54 to submit data from noncompliant wells -- excuse me, thermally noncompatible wells.
Q Thank you.
So my next line of questions are related to the cement bond log report. So, again, Mr. Iannattone, which member of your team would be responding to that?

A MR. IANNATTONE: Mr. Craig can respond to that.
Q Okay. Then we're going to go to Exhibit 81.01, which is the cement bond log report. And just the -- a few initial questions. So the cement bond logs included logs from January 2015; is that correct?
A MR. CRAIG: That's correct.
Q And my understanding is the logs he was examining were done during the work described in exhibit -- and I'm going to lay out the exhibit and note page numbers for the record. I don't need you to go there. I think you can take it subject to check, but it was during work described in Exhibit two oh -- 201 at pages 76 through 84, which was CNRL's workover of the 10-01, and, again, as I understand it -- and you can take this subject to check -- that work to make the 10-01 thermally compatible occurred between January 15th and January 23rd, 2015. Both zero MPa and 7 MPa pressure pass cement bond logs were run on January 20th. In the subsequent days, CNRL conducted two more operations. The thermal plug was run to 442 mKB, and the Wabiskaw B gas zone was reperforated. So my question is: Does CNRL agree that either of those operations could impact the cement bond?
A No. No, we don't agree.
Q Okay. Could you elaborate on that.
A The -- I'm sure ISH has reviewed that workover report.

It's certainly evident that the perforation operation would be on depth. So that would not impact the cement, the perforations that are in the Wabiskaw. And the setting of the patch is a -- it's a low-pressure job execution, so there would be no reason that would -- that would cause a cement integrity issue.
Q Does CNRL agree that the act of running a pressure pass of 7 MPa could impact the cement bond?
A Again, no, we would not say that it's going to impact the cement bond. The reason I -- I say that is that when that cement was placed, if you review the drilling record, the cement plug was bumped to -- I don't have exactly in my -- in front of me here, but I believe it was 5-and-a-half or 6 MPa, so a 7 MPa pressure pass would not impact that cement.
Q All right. Could you please go to Exhibit 65.01 at PDF 16. And it's just going to be the first -- yeah. The top of the page is terrific. Thanks.
So here, at the top of the page, CNRL states that: (as read)

The McMurray formation and Kirby Upper Mannville, Wabiskaw B [and, obviously, there was a preceding paragraph, but it indicates that] 50 percent of this interval indicates a good cement bond, and in the Kirby Upper Mannville II pool, 80 percent of this

interval indicates a good cement bond.
Now, the summary statements there, I note, are significantly different compared to the recent CBL interpretation report. And, again, that is at 81.01, and we don't need to jump to that, but at page 35 of that report, it indicates that the cement bond log can be considered in the 100 percent range.
So just having regard to the differences, 50, 80 percent, 100 percent, would you agree that interpreting CBL logs is subjective?
A Yes, we do agree it's subjective, which is why we had two independent analysis happen. The 50 and 80 percent numbers you see here were conducted by our well-integrity experts in-house, and the report in 88.01 was, of course, a third-party submission. However, both reports agree that there is, without a doubt, hydraulic isolation. Even with 50 or 80 percent of good bond, those zones are hydraulically isolated, and there is no channel that exists behind pipe.
Q Mr. Craig, is a 3-foot amplitude tool -- excuse me -- sufficient to investigate microannulus formed behind cement and dry mud cake?
A I would say that bond logging is a standard practice. I believe it is a requirement of several directives to analyze bond logs and understand the cement placement within the wellbores. And so the VDL tool would be a

standard practice to -- to evaluate cement placement.
Q Just one moment.
Did you see that the static and the 7 MPa pressure amplitude curves in the recent CBL report never reach zero mb?
A I did not notice that. I have the log in front of me, and I can check, but, certainly, I know that typically you only run tools up as far as possible, and you may not be able to pull the tool all the way into the wellhead. That may be the reason why it's not pulled all the way to surface. It's a length-of-tool issue.
Q Sorry. Did you -- okay.
All right. Do you agree that if both log passes for the VDL show poor formation arrivals, the cement is not bonding to the formation?
A I would -- I believe, and certainly the interpretation stands, that there is sufficient arrivals that indicate bond to formation.
Q But just in general, would you agree that if both log passes for the VDL show poor formation arrivals, the cement is not bonding to the formation? And I'm asking you that as a general statement.
A I -- I think in general, that is correct, that if you have poor VDL signals, you would suspect a weak cement formation bond.
Q Thank you.

A In this log, however, there are several intervals where there are strong formation arrivals.
Q Thank you.
So it's fair to say that many surface casing vent flow wells have excellent cement bond logs; correct?
A I -- it's probably a safe statement. I don't have the data to follow that up, but it's probably a safe statement. There is surface casing vent flow in this stream, yes.
Q And, Mr. Craig, are you familiar with case hole density neutron logs or chat logs to run on wells with gas channeling mysteries where CBL logs show good bonds?
A Yes. I believe there is a variety of tools that can also be ran if there are well-integrity concerns, yes.
Q And has CNRL run chat logs before?
A I'm sure CNRL has. I don't recall the need to run a chat log in the -- the length of time that I've been involved in the Kirby North project, which is now six years. But has CNRL ran them? I'm sure we have.
Q All right. Have you considered running chat logs in the 10-01?
A No, we have not.
Q All right. Thank you.
I'm now moving to more general questions on monitoring and review. And, again, Mr. Iannattone, if -- I'll -- I'll let you listen to the question

and -- and determine who on your team should respond.
So --
A MR. IANNATTONE: Thank you.
Q -- my first question involves -- if we could go to Exhibit 2.01 again, page -- PDF page 58. And I understand that this is the thermal wellbore compliance assessment from CNRL's application, and, obviously, an important part of the KN06 approval process is to report on the status of wellbores within the area of the drainage box.
So just in -- as a general question, does CNRL believe that assessing wellbore compliancy is a single-review process?
MR. CRAIG: Sorry, Gerard. You want me to take this, I assume?
MR. IANNATTONE: Yes, I do. Thank you.
A MR. CRAIG: Is it a requirement obviously of our application? It's a -- so this data is submitted once in the application. However, any wells that are identified as thermally noncompliant and then work is done to make them thermally compatible, Canadian Natural, as I alluded to in the 10-01 example, continues to evaluate the data that is being collected from those wells, and, like I say, in the 10-01 example, that's obtained through daily data collection and a review process.

Q And so it's fair to say that CNRL understands that wellbore integrity changes over time or could change over time?
A That's specifically with wells that are not thermally compliant, so they have casing or cement that would not necessarily withstand thermal temperatures. CNRL understands that we want to be monitoring those, yes, that there is potential for those conditions to change over time.
Q All right. If I could have you go to Exhibit 48.02, PDF page 14. And it's just at the top of the page there, yeah, so the second bullet under 'B'. So it states there that: (as read)

> There is no correlation between 10-01 pressure and temperature data and SAGD operations of the McMurray formation, therefore, confirming an effective barrier between the Wabiskaw B and McMurray formation.

So it's my understanding that the SAGD operations will create conductive heating, which will increase core pressure -- core pressures and temperatures above the steam chamber. What are the alarm conditions set for -- for pressure temperature increases at the 10-01 well?
A There is no alarm in place on the 10-01 data set. We

are collecting the data and analyzing for inflexions in the trend, but there's no alarm set.
Q All right. Given the dynamic nature of the pressures and temperatures reflecting the GOB zone channelling gas throughout 2019, how could CNRL conclude that there was not a correlation with operations in KN05?
A I believe that if you were to go to tab -- sorry, page -- I hope I have the page number correct -- 48 of 106, it's Tab 008, and we have submitted --
Q Sorry.
A (INDISCERNIBLE - OVERLAPPING SPEAKERS)
Q That's --
A Okay.
Q Sorry. I'm just trying to get the -- the citation right. So did you say -- did you mean forty -- Exhibit 48, page 106? Is that --
A Exhibit 48.02.
Q Yeah. Okay. And page 106?
A Sorry. I believe it's page -- I have page 48 here.
Q Oh, sorry. Page 48. Okay.
And, sorry, go on.
A So on the second plot is a comparison of the 10-01 pressures in the black line --
Q M-hm.
A -- at the nearby pressures from the nearest well on the KN06 pad. And, clearly, there is no correlation

between pressures in the Kirby North KN05 pad and the 10-01 pressures. And I won't be able to recite the paragraph, but ISH has also agreed that there is no correlation between the 10-01 pressure and the nearby McMurray KN05 operation.
Q Okay. One moment, please.
So, Mr. Craig, earlier you had stated that you are looking for inflexions in the trend. What magnitudes of inflexions are you looking for?
A We would be looking for anything that indicates a steam chamber has impacted the 10-01 well. So we know that the difference between our current steam-chamber pressure in the green line is at least 2,000 kPa different than what you see in the black line. So -- and that order of magnitude would indicate that the -- the barrier below the GOB or between the McMurray and the GOB has been breached, and there's a -- there's an issue. There needs to be a significant change to -- a -- a significant inflexion point to indicate an issue. Pore pressure increase would be a very slow response, slow pressure increase, therefore, a slow response.
Q All right. I have some questions on start-up operating procedure. Is that you, again, Mr. Craig?
A Yes. I'll -- I'll attempt to answer the questions and rely on my panel members to assist.

Q Okay. So we're going to go to your opening statement at 88.02, and if I could get you to go to PDF page 58.
So the AER, in its IRs, asked for clarifications regarding details of CNRL's enhanced monitoring and associated mitigation strategy. If your new enhanced operating procedure, which I understand is outlined on PDF page 58, had been in place for the KN02-04I, I believe -- I'm not sure if it's 041 or 04I -- circulation start-up, would you have been able to start this well below 6 MPa?
A So this -- page 58 is speaking to the controls that are in place during circulation --
Q M-hm.
A -- but they may not speak to the revised start-up procedure.
Q Okay.
A So there was a statement that you made. I just wanted to clarify.
Q Yeah.
A This well, it was started up using the revised procedure. It's not conclusive that we are able to remain below 6 MPa, this well and any well in the field. We feel there's a higher likelihood of being able to stay below 6 MPa, but it's not -- it's not a given.
Q Thank you.

We understand that gas lift to reduce fluid density in the well prior to increasing steam rate will lower the maximum circulation pressure BHP. With this mitigation procedure, would you need to go to 7 MPa?
A Yes. So what I was attempting to articulate is that the additional gas to be implemented before significant steam volumes, that will reduce the hydrostatic column, but the ultimate pressure that's required to lift the fluid to surface is really dependent on the reservoir. So we always will attempt to start up the well at the lowest pressure possible. We're -- whatever that pressure is that lifts fluid to surface, there's no need to go beyond that pressure.
Q All right. Thank you.
If we could go to 88.02, PDF page 61. And I'm just wanting to use this more for illustration purposes. It's not so much a question regarding -- regarding this particular page.
So just with regard to bottomhole pressure, it's measured at the heel of the wells with a bubble too; correct?
A During circulation, gas goes down the casing, and it's measured at the heel of the well; correct.
Q Okay. So when a restriction or a plugging happens at the horizontal lateral, do you agree that pressure at the toe will be undetected and higher?

A There is -- I don't believe our evidence indicates that we have observed plugging in the lateral section of the wells.
Q But if that was to happen, if --
A Yeah.
Q -- if there was a restriction or plugging in the horizontal lateral, would you agree that pressure at the toe will be undetected and higher?
A Is it -- am I able to communicate with my colleagues on -- on this issue?
Q Sure.
A That means do I request a breakout room? I'm not sure how that works.
Q I'm -- I am not entirely sure how that works, and so I think we can ask Ms. Turner.
THE CHAIR: Yeah. If there's a breakout room set up for them, you can send them to the breakout room.
MS. TURNER: Anastasia, please have them assigned to that breakout room.
So you should be getting a message soon. CNRL witnesses to join the room.
MR. THOMSEN: And, Ms. Turner, if I could have an invite to the breakout room for my second log-in, please.
MS. TURNER: Sure. There you go.

You should all -- yeah. Mr. Lavigne, you should have the invite to the breakout room.
MR. LAVIGNE: I haven't received the invite.
MS. TURNER: If you go to the bottom of your screen, it says "breakout room."
MR. LAVIGNE: Yeah. I'm not seeing that.
MS. TURNER: If you hover your --
MR. LAVIGNE: Oh, I'm sorry.
MS. TURNER: There.
Madam Chair, we've sent a message to that breakout room letting them know that they should join on their own when they're ready.
THE CHAIR: I did see that. I'm wondering if they're all familiar enough with Zoom to know how to do that.
MS. TURNER: Right.
THE CHAIR: Maybe you could send them a note with the instruction on how to do that and invite them back.
MS. TURNER: Okay.
THE CHAIR: It's been over five minutes, so ...
MS. TURNER: I can email Mr. Scrimshaw.
THE CHAIR: Okay.
THE COURT REPORTER: I'm sorry. Did you want that discussion on the record?

THE CHAIR: That's a good question. Sure.
THE COURT REPORTER: Okay.
THE CHAIR: Did you get it? If you got it, yes. If you didn't -- oh, here they are.
MR. CRAIG: Hello.
THE CHAIR: Welcome back.
MR. CRAIG: Okay. Thank you.
A MR. CRAIG: Yes. Thanks for the opportunity to break out there.
So I think we acknowledge that in the highly unlikely scenario that there is a plug in the lateral section, that the toe pressure measurements could be unmeasured; the toe pressure could be unmeasured.
We have the ability to observe -- or we -- we do have the ability to detect, possibly -- or this possible scenario, and that would be that our steam rate -- our steam injection pressure at surface would be climbing, attempting to squeeze steam into a shorter section of the lateral. So that would be an indication of a potential plug in the lateral.
In Kirby North, we have not observed this in the 96 wells that we started up, so I believe that the -- the likelihood of this happening is significantly low.
Q MS. BERG: Thank you.
So a follow-up question: How would you know, then, if hydraulic fractures are propagating at the

toe?
A Well, we would need to have a significant time and duration of steam injection at high rates that are increasing this toe pressure above the 7 MPa and 8 MPa fracture pressures. The -- the reservoir leak-off would suggest that that's not going to be possible. If we're going to get to that high a pressure, that plug at those steam rates is going to dissolve. This bitumen plug is going to become mobile when we're at that significant-enough steam rate that would cause a fracture.
Q Now, I'm going to just take one moment.
So, Mr. Craig, would it be fair to say that a safety factor for the maximum operating pressure using 6 MPa would be a real mitigation measure for this?
A No. No, I don't. You know, I -- I think we -- I think the evidence demonstrates that the 7 MPa pressure is already a low risk, and reducing a pressure -- or reducing the MOP from that 7 MPa pressure does not significantly reduce the -- it does not significantly reduce the likelihood of any fractures.
Q All right.
A I would --
Q Go ahead.
MR. IANNATTONE: If I could interject here.
Mr. Thomsen, do you have any comments?

MR. THOMSEN: Yeah. Thank you, Mr. Iannattone. I do.
A MR. THOMSEN: And so in our written submission, we have had discussion about the use of safety factors and also what is the -- what is the intent of Directive 86 and Directive 51 and whether those are appropriate to use.
And so, I mean, the -- the long and short of it, in summary, the -- those directives have safety factors that are applied for the life of -- of a well, for the life of the operation, and the question with respect to use of 7 MPa is for short periods of time, up to 14 days. And in practice, it's much shorter. We're talking typically one or two hours, if it's used.
So the -- we have safety factors that are built into the KN06 start-up plan. These safety factors are incorporated in the form of short duration of use of these pressures, a small injected steam volume that is really -- all the steam is condensed, and it's really just water, and then final -- finally, the monitoring of injection rates and pressures. So Canadian Natural has adequate mitigation built in with this and safety factors that are incorporated with the start-up plan.
Q Thank you, Mr. Thomsen.
I now have -- and I, again, think that these are questions for you.

Perhaps it's for you, Mr. Craig. I just -- I wanted to go to the questions on maximum operating pressure. And if we could first go to -- to Exhibit 2 -- 2.01, page 228, and it's Table 1, the Kirby North start-up data.
So you'll see there, sir, that there are three wells with the highest-circulation start-up pressure within pads KN02, KN03, and KN05; is that correct?
A MR. CRAIG: Yes.
Q Okay. So now I'd like you to go to 30.02, PDF page 127. And on this page and, I believe, the next, we have 96 wells listed; correct?
A Correct. Yes.
Q So I guess my question is: Why is there such a discrepancy between the two tables? The -- the maximum KN02 peak is 692 -- sixty-nine twenty-six from KN02-O9P. Data from the first table does not appear to conform with the second table.
A Right, right. So the question is: Why is the data different between Tab 37 and -- and the submission with the three wells? Is that the question?
Q Yeah.
A So when the data was submitted, the -- the three-well table submitted in 2019, the -- let me back up one step. I think I described that our pressure and temperature in our data collection system is quite

frequent. It can be up to one-second intervals that we're collecting a data point. And so when the data was pulled out of our data historian in -- the summer of 2019, I believe, was the time frame of the three-well table. That data was taken -- average pressure over every 30 minutes. So the data that you saw at the table with three is 30-minutes intervals taking an average pressure.
The data that you see on Tab 37 is taking the maximum pressure that the wells saw during circulation, even if that pressure was only observed for five seconds. So the reason why there's significantly more wells on Tab 37 in the PDF that we're seeing right now is because we're taking a more conservative approach around the pressures that were observed in circulation. The submission prior was taking some averaging over a 30-minute interval, which had the effect of reducing the -- the maximum pressure that would've been recorded.
Q All right.
A We -- we wanted to be as transparent as we -- as possible with -- with the data that was submitted. So that's how we got to Tab 37.
Q All right. Could I have you go to Exhibit 48.02. And, sorry, I don't have the -- I'll see if I can find the PDF page number. It's Tab 15B, but I'm not sure that

they're marked that well on -- on the -- it's -- sorry. I'm just going to confer. So is this Tab 15B of 48.02 or -- no, it's this one. And I'm -- I'm -- oh, it's actually -- it's page 1066 of 1066.

So why are the injector depths listed on average 495 metres TBD and producers are 490 metres TBD?

MR. IANNATTONE: Mr. Craig?

A MR. CRAIG: Yes. The -- the total depth TBD, why are the injectors -- or why are the producers shallower than the injectors? I may need to take this on a -- on a breakout or a -- come back to you with the answer. I believe it has to do with the wells being potentially toe up, but I'm right now just speculating. It could just be an error where we flipped injectors and producers. Could I -- could I take this question away?

MS. BERG: So I'm -- I'm wondering -- Madam Chair, I'm just wondering if it would make sense for him to do that in a break. I -- I'm not -- I'm fine if you want to confer with your colleagues regarding this, but, yeah, I'm just wanting to do what's most efficient.

THE CHAIR: Where are you in your questioning, Ms. Berg?

MS. BERG: I -- I have just a few -- a few left.

THE CHAIR: So you're thinking you'll be wrapped up sort of by 10, ten after 10 or 10:15?

MS. BERG: About that, but it, of course, depends on --

THE CHAIR: Depends on the answer.

MS. BERG: -- the breaks and --

THE CHAIR: Okay. I --

MS. BERG: But I do -- sorry. Go ahead.

THE CHAIR: Okay. So I was going to say, I've had a request for a break, so we could do it one of two ways. So we can break now and come back, and that would give Canadian Natural an opportunity to -- to perhaps find the answer to this question and then carry on, or we could carry on for a bit and then take the break.

MS. BERG: Why don't we carry on for a bit, take the break, and then I'll try to finish my cross. And -- and -- and then do a very quick wrap-up. Then -- and we can --

THE CHAIR: Okay.

MS. BERG: Does that make sense?

THE CHAIR: It does. I was just saying, I've had a specific request for a break --

MS. BERG: Okay.

THE CHAIR: -- so for five or ten minutes, and then we'll --

MS. BERG: Okay. And we'll see where we're at.

A MR. CRAIG: The well did not -- sorry. Just on this table, like, obviously, the wells have not been drilled for KN06. These are the planned depths.

Q M-hm.

A Typically, we would expect to see injectors more shallow than producers, and so, you know, they are within that range that our -- our final TBD depths will be in that 490 to 495 metres. So I don't know if that answers any of the questions that you were going to bring on, but please carry on. Sorry.

Q All right. Yeah. No. No problem. Thank you for that.

And, yeah, if you want to confer with your colleagues during the break and -- and add to that, I'm sure that would -- we would all appreciate that. If I could get you to go to Exhibit 88.02, PDF 43, please.

So I see here that the geo -- geomechanical model runs with the assumption that the injectors are at a depth of 477 metres. And so just having regard to the -- the material on the last slide we looked at, what will be the depth of the injectors?

A MR. THOMSEN: So why don't I take this question here.

The 477 metres is a -- the shallowest point within

the liner as far as true vertical depth from surface. As far as reconciling this with the previous figure, we're going to need a break or an undertaking to -- to answer that one.

Q Okay.

A But the intent with this is looking at the shallowest well on the pad.

Q All right. I just had a follow-up question if we're in 88.02. So if we could go back to PDF page 58.

And, Mr. Craig, I believe this question will be for you. So it's my understanding you said this well was started with the new procedure, which means that the BHP would be reduced to as low as possible with lift gas; is that correct?

A MR. CRAIG: No. This well was not started with a new procedure. Sorry to -- sorry if I wasn't clear. This well was not.

Q Okay, okay. Just one moment, please. Okay. Just one moment.

So, again, is it possible that this well could have been started below 6 MPa with the new procedure?

A So I think that was the question that was asked before, and --

Q Yes, it was.

A -- and I tried to articulate that it depends on a number of factors, and we would not conclusively be

able to say that this well would've initiated circulation under 6 MPa.
Q All right. Just some questions -- additional questions regarding the 10-01. So we understand from CNRL's evidence yesterday that CNRL believes the 10-01 had been flowing until the hard stop on January 7th, 2020; is that correct?
A Yes. I believe ISH and CNRL agree on that fact.
Q And you indicated you believe that ISH was producing that gas; is that correct?
A ISH is the operator of the 10-01 well.
Q Did CNRL visit the 10-01 well site between March and December 2019 to collect manual downloads of its gauges?
A Yes. We will -- we do collect manual downloads of the gauges periodically. So we would have staff on-site, yes.
Q Okay. Just one moment, please.
MS. BERG: So, Madam Chair, I believe that those are all my questions, subject to any follow-up from the response that CNRL will be working on during the break. So thank you to the CNRL panel for answering my questions.
THE CHAIR: Okay. That's good timing.
So why don't we take a break now, and if we come back at 10:30, Canadian Natural, will that give you the

time you need to sort out your response about the apparent flip on that table?
MS. BERG: And, actually, sorry, I was just advised by my client that I will have one additional question, which I will ask after the break.
THE CHAIR: That's okay.
MS. BERG: Again, it -- it should be, like -- yeah. It'll be minimal time, and so --
THE CHAIR: Okay.
MS. BERG: Yes.
THE CHAIR: So does ten -- if we go to 10:30, Mr. Iannattone, will that give your panel enough time to -- or I guess, Mr. Craig, you're the one who's got to find it.
MR. CRAIG: Potentially. I guess the question is: Is this an undertaking and we can have some other support staff dig through it, or is this something that we need to do on our own? I guess that's the little bit of question in the back of my mind.
THE CHAIR: Well, Ms. Berg?
MS. BERG: Well, I -- I would ask that you attempt to -- to address it through, you know, the normal convening, but if it is something that obviously cannot be -- be done with the team that you have in place, then, yes, we'll take it by way of undertaking.

So if you could just advise after the break, that would be appreciated.
MR. CRAIG: Sounds good
MR. IANNATTONE: Okay. Sounds good.
THE CHAIR: Okay. So we're adjourned until 10:30. Thank you.
(ADJOURNMENT)
THE CHAIR: So it looks to me like we have everyone present. Are we ready to proceed?
MS. BERG: I'm ready.
THE CHAIR: Okay.
MR. IANNATTONE: Madam Chair, we would like to ask for an undertaking, but I have a question first.
We were considering an undertaking and bringing the information in tomorrow morning, but if we do that, is the panel -- will the panel remain under oath until then?
THE CHAIR: On undertaking -- on an undertaking -- so you mean under oath? Do you mean so that they can't talk to anybody else, or are they still sworn?
MR. IANNATTONE: But we can't talk with our counsel?
THE CHAIR: No. On an undertaking, you could do what you need to do to answer the question; although, you shouldn't be asking for legal advice from

the counsel. I don't know why your legal counsel would need to help you with that question.
MR. IANNATTONE: Well, they don't. It's just that if we're -- if we're going to be presenting closing statements tomorrow, I need to participate in that process.
THE CHAIR: Absolutely. You can participate in that process, which then raises my second concern, which is since tomorrow is our day for final argument, it's entirely possible that Ms. Berg wants to see the response to the undertaking before she finalizes final arguments, so tomorrow morning is --
Oh, yes, Ms. Jamieson?
MS. JAMIESON: Yeah. If I could assist, I actually think that the response to the undertaking could be put together this afternoon and filed by the end of the day and that, therefore, we would get it on the record for Ms. Berg's benefit for the closing argument, and it would allow us to move forward with -- I do need to be able to work with the Canadian Natural witnesses to prepare our closing remarks.
THE CHAIR: Okay. So, Ms. Berg, would that work for you?
MS. BERG: Yeah. That's -- that's fine.
THE CHAIR: So let's proceed on that basis.

But also, Ms. Berg, we need, then, for the record the -- the specific wording for the undertaking that you want the panel to have, Ms. Berg. So can you do that for us.
MS. BERG: I can. And so the question, it related to Tab 48.02 -- sorry, not tab, but Exhibit 48.02, Tab 15B. Why are the injector depths listed on average 495 metres TBD and producers 490 metres TBD? And then, following that, there was a question: The geomechanical model runs with the assumption that the injectors are at a depth of 477 metres, based on Exhibit 88.02, PDF 43. What will be the depth of the injectors? And so that, I think, would cover all of the questions arising from -- from that line.
THE CHAIR: Okay. So, Mr. Iannattone or -- is that sufficiently clear for you to --
MR. IANNATTONE: Yes, it is. Thank you.
THE CHAIR: Okay. Thank you.
Q MS. BERG: Okay.
And so I just had, as I noted before the break, one additional question that I -- or a line of questions that I wanted to ask. So if we could go to Exhibit 88.02, PDF page 20.
Okay. So it's fair to say -- it's my understanding that CNRL has confidence in RST logs

coupled with interpreted steam-chamber temperatures and that they're indicative of steam-chamber development; is that fair?
MR. IANNATTONE: Jason Lavigne, please.
A MR. LAVIGNE: I'm sorry, Counsel. Could you please repeat. Do we have confidence in the RST logs? Was that the question?
Q Effectively, yes, that -- is it fair to say that CNRL has confidence in RST logs coupled with interpreted steam temperatures and that these are indicative of steam-chamber development?
A I think that's fair, yes.
Q Okay. So my question is this: How can CNRL run RST logs if CNRL does not drill an observation well in KN06?
A The purpose of the inclusion of this RST log was to demonstrate the confidence that we have and using this as an analogue from a mature producing property. This -- this is -- this particular example in Tab 21 is from Jackfish, which occurs in the same reservoir fairway with the same -- very similar reservoir and the exact same confining strata. So we use this data as an analogue for -- for the KN06 pad. We believe that the results obtained in this RST log are representative of what we would expect at KN06, and, therefore, we don't feel it's necessary to do this on all of our

developments. We take this data where we can. It's one of the benefits that Canadian Natural is able to leverage its large database of SAGD projects, and so we feel that this is representative, and because the reservoirs are so similar, this isn't required on KN06.
Q All right. So given that -- I take it the answer is that there won't be RST logs for KN06, and there isn't an intent to drill an observation well for KN06. What will be the monitoring techniques used by CNRL to monitor steam-chamber vertical growth in a highly heterogenous -- heterogenous -- I should know this word by now -- environment such as KN06?
A Our intent around observation wells is they're -- they're drilled later on if there's a concern about recovery or -- or chamber development, and -- and so it's -- it's evaluated as we feel necessary.
Q Okay. Just one moment, please. Just one moment.
So, Mr. Lavigne, I just want to clarify that we understood your recent response. You indicated that there will be an observation well drilled later?
A No, I didn't. It is -- it is -- some operators have used post-steam core to show that after, but I don't think you can drill an obs well into an active steam chamber.
Q Okay. All right. We just wanted to --
A Sure.

Q -- clarify that.
A I apologize for any confusion.
Q Okay. All right. I believe that those are my questions, and, again, thank you to the CNRL panel for responses.
THE CHAIR: Thank you, Ms. Berg.
So now I believe we have Ms. Hall up with questions from AER staff.
MS. HALL: That is correct. Thank you, Madam Chair.
Alberta Energy Regulator Staff Questions Canadian Natural Resources Limited
Q MS. HALL: So my first set of questions, I believe, is for Mr. Sverdahl -- I hope I'm pronouncing your name correctly, sir -- on the seismic evidence that you provided yesterday. So Ms. Berg had asked you some questions about detailed seismic analyses that might provide insight into faulting and fracturing of the containment strata over KN06.
Specifically, for the record, this is at the top of page 279 of the transcript from October 14th, 2020. You were asked whether Canadian Natural made use of pre-stack amplitude versus azimuth or velocity versus azimuth analyses to look for subtle directional amplitude and velocity variations within the confining strata. You responded that Canadian Natural did not

perform these analyses.

So my question is: Do you agree that in some cases, such analyses can be used to characterize fault and fracture density and orientation?

A MR. SVERDAHL: Thanks for the question.

VVAz or AVAz are techniques that have been potentially used to -- to understand fractures in some areas. However, as recently as, I'd say, February 2020, there's -- there was an article in the Leading Edge, which is the SEG, Society of Exploration Geophysicists, journal discussing -- discussing these techniques. The paper was called "A Skeptic's View of the VVAz and AVAz." The point I'm making here is these kind of techniques are, I'd say, at the bleeding edge, if not experimental, and -- and even in the academic world, there is questioning on the validity on these techniques.

So, no, Canadian Natural has not used these techniques on this project, and we don't believe that -- the current state of the industry knowledge that they're applicable to use here.

Q Okay. Thank you.

A You're welcome.

Q So my next set of questions is on -- or are on geomechanical modelling, specifically, I believe, Canadian Natural's internal geomechanical modelling.

So I think these would be for Mr. Walters.

A MR. WALTERS: That's correct.

Q Okay. Thank you, sir.

So Canadian Natural provides a summary of its geomechanical modelling and analyses in Exhibit 30.02 at page -- PDF pages 36 to 38 and a report summarizing the workflow and major results of its geomechanical study at Tab 42 of that same exhibit, PDF pages 158 to 178. At PDF page 25, paragraph 106, Canadian Natural states that: (as read)

> It is Canadian Natural's view that faulting is not a risk to the containment barrier at the KN06 box. Furthermore, the risk to the containment barrier from natural fractures is negligible due to the very low natural fracture density.

Then at PDF page 29, paragraph 133, Canadian Natural states that: (as read)

> For the KN06 containment barrier, the geomechanical modelling is independent of the natural fracture distribution and intensity. This is because the geomechanical modelling assumes the material has a low strength appropriate for the presence of pre-existing discontinuities.

So my question, sir, is whether you can clarify if

Canadian Natural's geomechanical modelling has accounted for natural fractures or faults.

A Sure. Thank you for the question.

So the modelling that I've done from an integrity-of-the-confinement-strata point of view requires strength properties for that confinement strata, and as is typical for caprock integrity analyses, the material properties assumed for those zones is assumed to be a post peak or a weakened strength that accounts for the potential of having natural fractures present. So it is a conservative assumption from a strength point of view.

Now, no faults were included in the model, and that was because no evidence was present to define those faults, from CNRL's point of view, and the same GEOSIM software and modelling approach has been used for other several other SAGD operations and operators that I've worked with. And in those cases, when faults have been included, it's because the seismic team can clearly see faults present on their seismic cross sections, which, for KN06, is not the case.

Q Okay. Thank you.

My next question is with respect to Exhibit 30.02, PDF page 34 at paragraph 154. Canadian Natural states that: (as read)

> It is commonly accepted that muds have higher

> horizontal in situ stresses than sands due to higher Poisson's ratios.

However, based on Tab 42 of Exhibit 30.02, PDF page 168, Table 2, it appears Canadian Natural's geomechanics modelling of start-up at KN06 used the same Poisson's ratios for the mudstone layers and the sandstone layers. Can you clarify Canadian Natural's view on the difference, if any, between the Poisson's ratio of mudstones and sandstones?

A Sure. So just to clarify that table presented on page 168, the Poisson's ratio that was used there is the same for both the sand units and the mudstone units and so, really, from -- for all of the McMurray. And -- however, the -- what was discussed earlier in terms of the Poisson's ratio having an impact on the initial stress state is a stress initialization issue. So if materials have certain properties and, specifically, the Poisson's ratio, and those materials are laid down and a -- a load due to gravity is applied to them, then shales, which typically have a higher Poisson's ratio than sands in that gravity-loading analysis, will generate higher horizontal stresses than the sand.

These properties that are presented in the table were more appropriate for the dynamic modelling of the process, and that's why there was no variation of

Poisson's ratio for that table input.
Q Okay. Thank you.
A Yeah.
Q Sorry. Did you have something more there, sir?
A No. That's good. Thank you.
Q Okay. So just a moment, please.
So can you then explain how changing the Poisson's ratio in the model would change the prediction results -- could change the prediction results?
A So in the modelling here that was performed, you know, all of the inputs were chosen to give a conservative estimate, and the model presented in the report and our submission was really focused on the problem of initiating and growing a fracture during the start-up period.
So, in general, the Poisson's ratio has a minor impact on fracture growth. The stress gradient which, you know, as I discussed previously, can be linked to Poisson's ratio, has a larger impact on fracture growth because that's one of the fracture-containment mechanisms. So even though in the model here, I assumed the cost-to-Poisson's ratio, the fracture -- the higher stress gradient in the mudstone layer was used as an initial stress state and so was present and, therefore, included as a stress-containment mechanism. But, in general, for the fracture-growth predictions

and fracture initiation, the Poisson's ratio has a very minor impact.
Q Okay. Thank you.
Okay. I now have a question about Exhibit 30.02, PDF page 34, paragraph 155. Here, Canadian Natural states that: (as read)
The stress contrast between the McMurray post B2 reservoir and mid-B1 mudstone provides an impediment as it will constrain hydraulic fracture growth. The hydrostatic head of water between the mid-B1 mudstone and the shallowest KN06 well is 0.2 MPa.
Can you explain how this hydrostatic head was calculated?
MR. THOMSEN: Yes.
And, Mr. Walters, if you're okay if I could jump in here?
MR. WALTERS: Absolutely.
Q Thank you, Mr. Thomsen.
A MR. THOMSEN: So the hydrostatic head was calculated based off a true vertical depth difference between the shallowest wellbore and the base of the mid-B1 mudstone above that point.
Q Okay.
A So, specifically -- I think it's on the next page here -- we have the shallowest wellbore at 477 metres,

true vertical depth from ground level. And on this equation up in paragraph 154, it's 455 metres. So that's a difference of 22 metres, and hydrostatic head of water being 10 kPa per metre, that works out to 0.2 MPa.
Q Okay. Thank you.
Can you clarify the -- the temperature of the -- the injected fluid that was assumed for this calculation?
A Right. So steam is being injected at a low rate, and between the wellbore heat losses and heat losses within the liner as well as significant heat losses within the -- the formation for -- I mean, if we consider a hydraulic fracture having an aperture of sub 1 centimetre, there's a lot of surface area for heat transfer within the formation. So the -- at the wellhead we're injecting steam at low rates, and the -- any steam vapour is going to condense and cool down, so we'd have warm or cold water in the reservoir.
Q Okay. Just a moment, sir.
Okay. Assuming the -- the temperature of the injected fluid remained high, was still high-temperature steam, would that affect the calculation of hydraulic -- hydraulic head?
A If there was a steam chamber developed and so we had a portion of the reservoir at saturated conditions with

steam-vapour saturation, then the hydrostatic head would use a density of that steam vapour, and that would be less than 10 kPa per metre. However --
MS. TURNER: Sorry. May I interrupt. Sorry. I just have to interrupt. I just want to make sure Ms. Jamieson is back in the call. Thank you.
A MR. THOMSEN: However, for initiating steam circulation, we -- we do not have a steam chamber that has developed. The purpose of the steam circulation is to heat up the liquid between the injector and producer such that we could start to have a fluid flow with relatively small pressure differences through the porous media. So there is no steam chamber developed, and during circulation initiation, this is a liquid-filled system.
Q MS. HALL: Okay. Thank you.
And so I believe my last question is for Mr. Boone.
DR. BOONE: Yes. Thanks.
Q Hi, sir.
In Section 8 of your report, which is at Exhibit 45, PDF page 197 through 199 -- I don't think that's quite correct, but you assess the risk of induced fractures during start-up breaching the containment barriers at KN06. On PDF page 197, in the first paragraph of that section, you state you

evaluated that risk using the risk matrix provided by APEGA, which appears on PDF page 198 or, in larger form, on PDF page 188.

In summarizing the results of your risk assessment on PDF page 199, you state that: (as read)

> Based on review of previous Kirby North SAGD well start-ups, it is conservatively estimated that there is less than a 10 percent likelihood that a fracture which could potentially impair a Wabiskaw gas well will be induced at one or more of the KN06 SAGD wells during start-up. [And that] After consideration of the stress and leak-off barriers to vertical fracture propagation between the SAGD wells and the Wabiskaw gas zones, it has been assessed that the likelihood of a fracture which could potentially impair a gas well propagating into the Wabiskaw gas zone is less than 0.1 percent, and given the limited dimensions of any single fracture, the likelihood that a fracture actually does impair a gas well is less than 0.01 percent.

My question, sir -- and I -- I know that you did go through this to some extent yesterday, but could you provide more detail on how these quantitative

probability values were calculated.

A Sure. So the -- the quantitative portion of it is the -- or at least the initial quantitative portion is that -- assume -- it was assumed -- identified one fracture event out of 96 wells that previously started up at KN06. So that was 1 out of 96.

As I read the questions put forward by the AER, they wanted us to look at the KN06 pad as a whole. So I -- I said, Okay. Any one out of -- any one of the 18 wells could fracture. And so 18 over 96 gives you approximately a 20 percent chance, okay, assuming 1 out of 96 times 18; right?

Now, however, the volume that went into that fracture in the one identified case was really small. It was only 1.8 cubic metres. In order for a fracture to propagate up through the overburden -- or through the confining strata and impact a Wabiskaw gas well, it would likely have to be orders of magnitude in volume.

So I conservatively made the -- the assumption, then, that there was a 10 percent chance of such a fracture actually occurring. Okay? So -- so that's somewhat less than the 20 percent but reflecting the fact that it's a much larger fracture.

The -- the likelihood that -- that the stress containment will act to impair -- impair or contain a fracture, I assume that it would be 90 percent

effective, and that moves you down one category in terms of the risk assessment.

And that's based on my personal experience and looking at the fact that there is a significant stress contrast in -- in all of the available tests in the area. And so there's high confidence there is a stress contrast there.

The leak-off, similarly, there's clearly several formations there where fluid leak-off could occur. And so I made the -- the conclusion, I guess, that -- that that leak-off would also be 90 percent effective in reducing -- or in containment of a fracture. And so that moves you down one more category.

And then, lastly, if you're looking at geometry -- so -- and I think this could -- this may even be a 1 in 100 hundred or 99 percent chance -- is that fractures really are local, and so a fracture that goes up from the -- let's say, one of the injectors or producers, its -- its imprint or area that it might impact above the KN06 pad might be something like 10 metres wide by 50 metres long depending on the dimension of the fracture.

So if you have a gas well, it would really need to be in that box, that 10-metre-by-50-metre box, and then you can look at that box relative to the complete size of the KN06 box there or at least the KN06 pad area,

and -- and it's probably -- that's about 1 percent of the box area -- or of the KN06 pad area. But I -- I assumed that it only reduced the risk by a factor of -- of 10 percent.

So in the end, that's how I get to the -- the final risk percentage.

Q Okay. Thank you, sir. Those are all of my questions for you.

And now I have some questions on -- I'm not sure if these will be for Mr. Thomsen or Mr. Craig, so I will ask the question, and, Mr. Iannattone, you can determine who is most appropriate to answer the question.

So there was some discussion on this point earlier this morning, but at Exhibit 48.02, PDF page 14, just -- it's at the 'B' point there. We've seen this again already this morning. Canadian Natural concludes that pressure and temperature data at the 10-01 well does not indicate that SAGD operations of the McMurray formation are -- or does not indicate any correlation between the 10-01 well and SAGD operations of the MCMURRAY -- hydraulic formation, which confirms effective barrier -- ineffective barrier between the Wabiskaw B gas zone and the McMurray formation.

So my question is: If communication did exist between the Kirby Upper Mannville II pool and the

McMurray -- understanding that Canadian Natural takes the view that it is not currently in communication, but if there were communication, what impact would this have on SAGD operations?
MR. IANNATTONE: Mr. Thomsen.
A MR. THOMSEN: Okay. Thank you for the question.
So what impact would it have on the SAGD operation? So if there -- if there was communication between the two, some of the injected fluids would be flowing in some manner into that -- into the gas-over-bitumen pool. So we -- we would have some unexplained loss of fluids with injection. There's likely some insufficiency associated with that, so that could -- inefficiency would show up with a C model ratio.
And as far as a water balance -- so I -- I was talking about the unexplained losses would be -- one thing that we do is we monitor differences between steam injection and water production. And our goal in Kirby North is a balanced operation, so we would expect a water-to-steam ratio around 0.98 to 1. So it's -- it's fairly predictable.
So am I answering your question, or have I answered your question?
Q I believe so.

A Sorry. One other point. Let's say there was containment, and then there was a point where there no longer was containment, a flow of some manner started to go into the gas pool, that would also show up with our bottomhole pressures. And so with relatively constant steam injection, we would start to have decreasing bottomhole pressures. And so either -- and with the bottom water, I mean, our objective, our operating philosophy, is to have a steam-chamber pressure that's essentially balanced with the McMurray bottom water. Any decreases in the bottomhole pressure, our natural response would be to increase steam rates. So we would see an inflexion with steam injection into one or several wells.
Q Okay. Thank you.
So assuming Canadian Natural observed such impacts to its SAGD operations, what could Canadian Natural do to mitigate those impacts -- what, if anything, could Canadian Natural do to mitigate those impacts that would also mitigate any impacts to the GOB?
A Okay. So I think there's at least two parts to this answer. The -- the first aspect is ISH has raised concerns multiple times about operating with thermal pressures above 6 MPa and up to 7 MPa, and as we've outlined in our IR responses to the AER, during this short period of time during initiating circulation, we

would simply shut down steam for the well that we're trying to initiate steam circulation with.
So the -- the proactive approach is: If this is occurring during attempting to initiate steam circulation, we would shut down steam, and then we would assess and -- and evaluate what's happening.
The -- the second issue or the potential risk that ISH has raised is flowing up the 10-01 wellbore, and so, again, we have -- we have downhole pressure and temperature monitoring in the 10-01 well, and so if this was occurring, we would be able to -- to see it with the downhole measurements. And so as far as mitigation, I mean, we would -- we would need to assess, sort out whatever the requirements are as far as a partner -- our plan with ISH and then ultimately affix the wellbore conduit in the 10-01 well.
Q Okay. Thank you, sir.
So I believe I am onto my final question. In -- in its hearing submission at Exhibit 29.01, PDF page 8, paragraph 7, ISH stated that: (as read)

> In the event of a breach of the barrier or top seal of the bitumen that results in steam entering the GOB zone, the gas zone will sour.

Yesterday Ms. Giry clarified that this would happen through aquathermolysis. So my question is: If there

were communication between the Wabiskaw B and to the McMurray formation, could repressurization of the Wabiskaw B prevent souring of the GOB?
MR. IANNATTONE: Okay. I don't have any volunteers. Yeah. Can we take a breakout room on this one, please.
MS. HALL: Ms. Turner?
THE CHAIR: How long do you think you'll need?
MR. IANNATTONE: Five minutes.
THE CHAIR: Yeah. Sure. Ms. Turner, can you invite the Canadian Natural panel to join a breakout room?
MS. TURNER: You should be able to join now.
THE CHAIR: Okay. Thank you.
MS. TURNER: It's just the first time, I think.
Madam Chair, they should -- the witnesses should all be back in the main room now.
THE CHAIR: Yeah. They appear to be.
So, Mr. Iannattone, do you have a -- oh, Mr. Thomsen is going to answer.
MR. THOMSEN: Yes. Thank you.
A MR. THOMSEN: Could the question please be repeated.

Q MS. HALL: Sure. If there were communication between the Wabiskaw B and the McMurray formation, could repressurization of the Wabiskaw B prevent souring of the GOB?
A Thank you.
So in order to answer this, I'm going to put hydraulic fracturing in the parking lot. My understanding of the question is that it's not related to a question of hydraulic fracturing. Let me know if I'm misunderstanding that.
So if there were communication, there's -- there's two aspects to this answer. The -- the first one, that is, as far as repressurizing the gas over bitumen, I would say that's independent of -- of vertical steam chamber development, and so the confinement strata is an effective barrier. I think we've clearly shown that. But the -- we need to have an effective barrier to vertical chamber development irregardless of the pressure in the gas over bitumen. So that's Part A.
Part B, hypothetically, if there is some open conduit in between the McMurray formation, the post B2 reservoir and the Wabiskaw gas over bitumen, then the pressure difference between the two does matter. So if the GOB was repressurized -- and currently there is an upward pressure gradient, but if it was repressurized, theoretically, this could be a downward pressure

gradient on it between the gas over bitumen and the McMurray formation, and this would prevent any potential reservoir fluids or steam from flowing upwards through some hypothetical conduit -- open conduit into the GOB.
That being said, the -- the volume of gas to repressurize the GOB is significant; it's large, to the point that we'd have to re-evaluate the economic viability of the KN06 development.
Q Okay. I think those -- that answers all my questions, sir.
And I believe that was the last of my questions for this witness panel. So thank you very much.
MS. HALL: Those are my questions, Madam Chair.
THE CHAIR: Thank you, Ms. Hall.
So through the magic of alternate electronic communications, I know that Commissioner McKinnon's question or questions were answered.
So, Commissioner Zaitlin, do you have any questions for the panel?
DR. ZAITLIN: Yes, I do, Madam Chair. Thank you.
Alberta Energy Regulator Panel Questions Canadian Natural Resources Limited
Q DR. ZAITLIN: The first question would be

for Mr. Sverdahl or Mr. Lavigne.
One of the potential risks being discussed is the communication pathways of conduits for fluids via faults or fracturing. Has CNRL conducted any semiregional studies of faulting patterns in the Kirby or the greater Kirby area utilizing other techniques? Examples would be, like, high-resolution aeromagnetic or HRAM to map out regional faulting geometries. And, if so, what were the results?
MR. LAVIGNE: I was wondering if Mr. Sverdahl was going to answer that.
A MR. SVERDAHL: We -- I think we have some aeromagnetic data within the area that -- that we do look at from -- from time to time here. I don't think we've conducted a -- a regional fault study, per se. However, we have noted faulting in -- in areas within our -- our thermal assets. Primrose is an example. We also have properties north -- north of Kirby North, Gregoire Lake, which is adjacent to Long Lake. We note that faulting is happening up there, significant faulting, likely due to -- to salt collapse.
We do use regional publications. We included a figure from the AER/AGS Study 95 on -- on salt collapse. So we do incorporate that kind of work into our interpretations. However, we just -- we haven't seen any -- any issues of faulting over our operating

assets.
Q And so nothing in the immediate KN06 drainage box area?
A Nothing in the immediate area. I think we do notice on aeromag that there is some deep-seated anomalies to the north potentially, Snowbird -- Snowbird Tectonic Zone, but it does not appear to be at all an impact on -- on our -- our operating asset at KN06.
Q Thank you very much.
A Thank you.
Q My second question would be directed to Dr. Boone.
Does the orientation of the SAGD well pairs -- are they dependent on the regional stress regime, or is it solely a spacing issue associated with the bitumen distribution?
A DR. BOONE: Sorry. Can you repeat that question, please.
Q Sure.
The orientation of the SAGD well pairs, are they -- have any dependency on the regional stress regime in the area, or is it because of other factors like spacing issues?
A I'm maybe not the best person --
Q Okay.
A -- because I wasn't involved in the KN06 orientation. But just in general, I'm going to say geology rules, and you put your wells in the best reservoir at the

orientation that allows you to recover the most resource, and -- and stress generally is not a consideration --
Q Is --
A -- but it --
Q Sorry. Go ahead.
A But if one of the other CNRL folks wants to add to that, they can.
A MR. IANNATTONE: Yeah. I -- I would just say that that answer is correct. We're orienting the wellbores to maximize the recovery, and we're not considering stress.
Q Is stress a consideration on the fracability of the sealing units?
A DR. BOONE: I can answer that. Definitely. Yes. Stress -- I think, as Mr. Thomsen said previously, stress really is the control on the fractures. The -- the material strength in resistance to fracturing is called "fracture toughness," but for rock, you can basically assume it's close to zero.
Q Is there anything unique about what's happening in the KN06 area?
A Not that I have seen.
Q Okay. And the last few questions will have to do with Exhibit 88.02, if we can bring that up, please. And it'll be PDF page 10. So I think it would be for

Mr. Lavigne.
So we've -- we've had a look at this schematic a couple of times, both from CNRL and by ISH, and one of the observations would be, in the formation and timing of the post B2 reservoir and the non-reservoir IHS, is the bounding basal surface, which I'm going to call the "sequence boundary" going forward.
So to Mr. Lavigne, is it possible for the sequence boundaries to have a sufficient reservoir quality to be a potential pathway for the migration of fluids away from the steam chamber in the KN06 box?
A MR. LAVIGNE: Just for clarification, you mean laterally into what's depicted as the McMurray C in those diagrams?
Q The sequence boundary would be from the base, along the side, and up into the interfluve. And can the interfluve then be intersected with another pathway that may cause a torturous path of migration?
A Okay. I'll take a -- take a stab at this. The -- first of all, the -- the -- the basal unconformity cuts into the McMurray C. There are sands in the McMurray C that are lateral to that, but outside of the basal unconformity in the interfluve regions, the B2 mud is preserved, and so it -- it provides sealing capacity outside of the -- of the unconformity.
The -- there are also -- there are also within the

post B2 valley -- as I alluded to under cross-examination yesterday afternoon, this cartoon is a -- is a very simple depiction of the internal architecture of the post B2 fill, and based on 3D seismic analysis of nearby reservoirs in the same valley fill, we do observe that there are multiple terraces within the post B2 fill, and when you examine the KN06 drainage box, it -- it does not occupy the entire incised valley fill of the -- of what's depicted here as the post B2 reservoir. And so there are non-reservoir older terraces that are -- that are preserved within the valley fill, and they would provide lateral containment of the reservoir.
Now, when we -- when we look at the plan development, our well spacing is -- is 60 metres between -- between wells, and what we -- what we see over the -- when the -- when the pad reaches its -- its economic limit, the steam chambers have coalesced, and so what we look -- and that's within good reservoir, high-permeability reservoir. When we consider the effect of the lateral migration of steam outside of the main reservoir fairway, which the KN06 box is placed in, we would expect much slower lateral development of the -- of the reservoirs.
And so even if we allowed for -- a triple the well spacing, say 180 metres, that's one of the reasons why

when we -- when we showed our mapping area, the mapping extent is much bigger than the box, and in the -- in the north-south direction, we -- we mapped 380 metres.
So we think that it's -- it's -- that's a very conservative -- you know, it's -- we've -- we've looked well beyond reasonable reservoir. We've looked well beyond the lateral extent of reservoirs, and the -- and the KN06 box is placed in such a way that it's bounded laterally by non-reservoir facies, and so we think that -- we think that the -- the mapping extent laterally is -- is very conservative and -- and much larger than, say, three times the well spacing. So we -- we think that the steam chamber does not have any lateral ability to -- to leave the post B2 valley and pass through the unconformity.
Overtop of the box, the -- the post B2 non-reservoir facies, although there are thickness variations within it and, as we discussed at length yesterday, there are variations in the sand content of the IHS units that cap the valley fill; however -- and I -- I would add that on 3D seismic, we actually see the abandonment plug of the -- of the upper tier, which is off into the north of the KN06 pad. And so we -- we have an idea about the size of the potential point bar deposits that -- that are on top and cap the reservoir, and we've mapped a continuous muddy to mixed IHS facies

across the entire post B2 valley fill. And so the upper tier also appears to be sealed.

And so I'm not sure if I've gotten exactly to your question, Dr. Zaitlin, but I -- I believe that we've tried to demonstrate that laterally, away from the unconformity, there is a seal. Where the post B2 reservoir unit may come into contact with the hummocky cross-stratified sands of the upper B2 regional sequence, the permeability differences are -- are -- are quite profound, and we don't feel that there's the potential for lateral leakage of the steam chamber that way.

Q Thank you. Thank you very much for that.

Can we just turn to PDF page 14 now. So if I understand you correctly, you have the valley and terrace geometries laterally to the main system, and then within the system, within your post B2 reservoir, like in your type well here at 11-01, you have a 15-metre-thick sand package broken up to three 5-metre, roughly, thick sands, and on the GC-MS plot that you've showed us, that you've circled, there is a potential barrier between the top and the middle of those two sands; correct?

A Yes.

Q That's right.

So each one of those are individual channels or

point-bar-type sequences within the greater post B2 reservoir. Did you just mention that you were able to map those out by utilizing 3D so that you have their distribution?

A I would say not in KN06 but within -- within the -- the same valley system. So one of -- and I believe you touched on this yesterday in your questioning. Are these interpreted to be single 40-metre-thick incised valley fills, or is there more stratigraphy? And that would -- that would speak to potential barriers within the system, as you mentioned, you know, perhaps a series of, say, 5-metre-thick channel deposits.

When -- when Canadian Natural first evaluated its Kirby South development in -- in the same architecture valley fill, it was assumed that all of the sand within the valley fill was -- was part of that. And it was difficult, perhaps, to pit the base of the incision to actually identify the unconformity -- the basal unconformity, and often at Kirby South, for example, it was a sand-on-sand contact, maybe with a breccia, maybe not. So there was a little bit of uncertainty picking that.

However -- and so we -- we learned by examining the 3D seismic the -- the sort potential for terrace architecture within the valley fill, and so then we take it to north to Kirby North and specifically KN06,

there similarly is the potential to misidentify the unconformity if it happens to sit on McMurray C sands.

But in the case of Kirby North in KN06, the bottom water is higher in this area compared to Kirby South, and that effectively pushes you up out of the complicated architecture at the bottom.

In -- one -- one comment that was raised yesterday is that these are -- these are fairly narrow incised valleys on the order of, you know, maybe maximum 2 miles wide, and yet they're 40 metres deep, and -- and so the -- the proportion of, say, channelized thalweg facies to point bars is out of scale. And so I -- I think in -- in the Kirby North, Pads 1 to 4, I think we actually can sort of see the base of that meander belt, and it's about 15 metres. So the 40-metre-deep incised valley is actually subdivided into 25 metres of clean sand, and then the point bar sequence on the top. When we look at the -- the abandonment plugs that we see at the top of the reservoir unit and we do the math on the width-to-depth ratios, we come out with the meander-belt thickness of around 12 metres or so.

And so it appears like there's potentially another unconformity within the valley fill sequence, and I believe that that explains some of the GC-MS results where we seem to have multiple barriers even within the

post B2 fill. So I think that there's the potential for complexities that we may not be able to resolve in -- in particularly sandy sequences where discrete mud breaks are not -- are not present. And so we really do the GC-MS to evaluate the potential for the -- the compartmentalization of the reservoir.

Q Thank you very much.

One last question. When you're talking about you're his or your inclined heterolithic stratification associated with the point bars, are we talking about fluvial point bars, estuarine point bars, or, if we have more than one age, both?

A Well, that is certainly a hot topic amongst academic circles these days. And, you know, I -- I was a part of the Ichnology Research Group at the University of Alberta, which, you know, initially had interpreted the presence of the brackish-water trace-fossil suite to indicate estuarine conditions.

However, many years on with the incorporation of 3D seismic from wide areas over the base and in specific areas, I think that we have seen that these incised valley fills, which occur at several different stratigraphic horizons in the upper McMurray, seem to show in the upper portions thalwegs that bounced from wall to wall within the valleys, and I think people like Professor Blum in Kansas would argue that that's a

completely fluvial morphology. And I think that we feel -- I tend -- I tend to agree with that, and I think that the most parsimonious interpretation is that these are completely fluvial systems, and in the Lower Cretaceous, the largely cylindricus-dominated suite is happening in purely fluvial settings. Because I don't think the 3D -- or, sorry, the planform morphology of the channels is consistent with any sort of estuarine conditions.
Q Thank you very much.
DR. ZAITLIN: Madam Chair, that's it for me.
THE CHAIR: Thank you.
I do have a few questions.
Q THE CHAIR: So sticking with the theme of the GC-MS data, if we could pull up Exhibit 30.02, PDF page 18. Okay. Maybe not. Let's try that again. Oh, sorry. Page 109. There was the reference, and then there's the chart.
So what I'm looking at -- I'm wanting to understand if I'm reading this correctly, and on the chart, it appears to me that there are no samples taken between the post B2 incision top and the red dashed line immediately below it that falls between 470 and 465. Am I reading that correctly? Were there no samples there?
A MR. LAVIGNE: Yes. It's a -- it's a

mudstone-rich portion, and -- and I don't believe there's significant volume of hydrocarbons able to be recovered from that to do the testing.
Q Okay. Thank you. I don't like to assume anything.
On the same exhibit, PDF page 31 -- I don't think we need to turn to it, but we can if the person that Mr. Iannattone thinks should answer the question wants to -- there's a reference in paragraph 143 to: (as read)
Circulation start-ups with bottomhole pressures between 6 to 7 megapascals allowing for operational efficiencies and smoother central processing facility conditions.
And I would just like someone to elaborate on that for me.
MR. IANNATTONE: Mr. Craig, please.
Q THE CHAIR: You're muted, Mr. Craig. We can't hear you.
A MR. CRAIG: Sorry about that.
What we're -- what happens -- so when we're unloading wells -- when there's lower pressures being used, there are slugs that -- wells will slugs. So they'll have kicks of fluid to surface, kicks of fluid to surface, and then they will not circulate.
So as we're unloading those wells, those slugs at surface cause pressure impacts at the plant, the

facility, and they have been known to not -- you know, we high-level vessels. Will -- will cause CPF upsets. So that's -- that's what we're discussing there.
Q And then I'm -- so -- and I'm thinking back to some questioning earlier this morning. It's possible to start up at 6 megapascals, although in some cases perhaps not easily, but, operationally, it's -- it's preferable to start up at a higher pressure, if that's possible or appropriate in the circumstances?
A So I would say we want to efficiently unload the wells as quickly as possible using the lowest pressure possible, and 7 MPa allows us to do that. That gives us the operational flexibility to have the wells unload in one or two or three or less -- or, you know, those amount of, you know, fluid slugs to surface, and if we are forced to limit ourselves to a lower pressure, we'll have these operational inflexibility, or we'll -- we'll be assuming those -- that slugging period for a longer time.
Q Okay. Thank you.
So then in Exhibit 63.01, or -- sorry. It appears in both places, so I've got two different references. The easier one to go to is actually probably Exhibit 2.01 and PDF page 139, and I think it's paragraph 12, although since I don't see paragraph numbers, I don't know how I came up -- came up with a

number. Maybe I'll just read what I'm talking about, and if you are concerned about the accuracy of my note, then we can -- I can get us to the right reference.
But there was a comment: (as read)
To the effect that although the lateral extent of IHS units had been estimated and modelled, operational issues will arise due to the uncertainty with the effective vertical and horizontal permeability encountered.
And then there was a suggestion that some further modelling might be necessary or appropriate.
So, again, Mr. Iannattone, I'll let you tell me who is the appropriate person to respond, but can you just elaborate on that for me in the context of whether that's simply related to steam-chamber development or something more. Again, I don't want to assume.
MR. IANNATTONE: I think this is going quite a ways back here. I think we'd like to have a breakout on this one. Is that possible?
THE CHAIR: Okay. Well, let's set that one aside. Rather than taking the break now, 'cause I'm looking at the time, let's set that aside for a minute. I'll go through my other questions, and then maybe what we'll do is take the midday break then before any redirect so that you can -- and then you can

come back after the midday break and give me the answer if --
Ms. Jamieson, will that work for you? Okay. I'm getting a nod.
MS. JAMIESON: Yes.
THE CHAIR: Okay. Thank you.
So, yes, you can --
MR. IANNATTONE: And so --
THE CHAIR: -- come back to me with that one after the break.
MR. IANNATTONE: Just before we move on, can you repeat the question one more time, please.
THE CHAIR: Okay. So there is a reference in my note. Obviously, I have to go back and double-check. It was that in Exhibit 2.01 at PDF page 139: (as read)

> To the effect that although the lateral extent of the IHS units have been estimated and modelled, operational issues will arise due to the uncertainty with the effective vertical and horizontal permeability encountered.

And then I think there was a suggestion that further pad modelling needed to be undertaken, and my concern was -- I look at that and think, Well, that's got to do with steam-chamber development, but I don't want to

assume that's the case.
Oh, Ms. Jamieson is waving at me. Yes.
MS. JAMIESON: I just want to -- if they're going to work on this on the break, what I'm noticing about the reference you did give, assuming it's correct, is it's page 139 of 243. At the bottom right-hand corner, it says "ISH Markit", which -- so I believe it -- this -- if it is this reference, that would've been a report filed by ISH in the early days of this proceeding. And so -- so I just want Canadian Natural's witnesses to be aware of that when they go to look for the reference.
THE CHAIR: Thank you, Ms. Jamieson.
MR. IANNATTONE: If that's the case, is the question still valid to CNRL, if it's an ISH document, which it appears to be?
THE CHAIR: Well, let's hear -- so we can do it this way. So let's --
MS. BERG: Sorry. I might be able to help.
THE CHAIR: Okay.
MS. BERG: It's my understanding that this -- and I don't have the document in front of me, but it's my understanding that this quote from IHS Markit is in turn a quote from the original application, but that is subject to check. So that

might be helpful to you and the CNRL witness.
THE CHAIR: Okay. Thank you.
So when you said the "original application", you're talking about the original application for KN06?
MS. BERG: I believe so, yes.
THE CHAIR: Okay. Thank you.
So another question arising out of my review of Exhibit 63.01, which, Mr. Iannattone, is, in fact, ISH's reply submission, but it raises the question that, I think, only Canadian Natural can answer. It's ISH's evidence that on May 22nd, 2014, Canadian Natural requested ISH's agreement to abandon the 10-01 well. So, again, I don't want to make any assumptions about why that might've been the case. So I'm wondering if that's correct from Canadian Natural's point of view and, if so, why that request was made.
A MR. CRAIG: Yeah. So I can -- I can answer that one. So as part of the KN06 application, we, of course, did the thermal compatibility review. The 10-01 well was flagged, obviously, as being not compliant with the thermal operation, and -- sorry, and this was not necessarily specific to KN06. This well is within 300 metres of our KN05 pad. So it was flagged back in 2014.
The requirement at the time was to mitigate those wells, repair them, or abandon them prior to the

drilling of Kirby North, and so we engaged in discussions with ISH at that time around potential abandonment and remediation options available.
Q Okay. Thank you. That's helpful.
I'm just crossing off questions that I came to that were answered.
So, Dr. Boone, I have a couple of questions that, I think, are for you.
At one point in your report that's included in Exhibit 30.02, I think you say that the barrier does not need to be continuous over even the KN06 box to be effective. Can you help me better understand what you mean by that.
A DR. BOONE: Sure.
I -- I -- I don't recall exactly where I say that, but, again, it relates back to if fractures are being generated, they're -- they're local events. And so, you know, as they rise up from -- from the wellbore, they spread out, but they're going to spread out to typically widths that might be 40, 50 metres, and -- but they're very thin too; right? They're only, you know, typically millimetres opening on these fractures.
So in order to be contained, there really only has to be a local seal or a local barrier there, and, you know, they -- it doesn't have to be a continuous barrier over the pad like we would normally want if --

for pressure containment because fractures, you know, really can't find tortuous pathways around the barriers.
Q But to be -- for the barrier then to impede the course of the fracture, I mean, the geometry would be such then, if I understand you correctly, that the fracture actually has to meet the barrier. So if you have a barrier that's not continuous and a fracture that somehow misses the barrier -- I guess that's where I was a little confused.
A No. I mean, that's correct. Now, if you're looking at a stress barrier, though, you know, what happens is in -- in -- in the -- in -- at least this is what people understand about stresses and having measured them -- is that they're sort of continuous through a given layer.
So if you look at in particular -- like, that B1, which is a very muddy, sandy layer, within that, say, 5 or 10 metres, you're going to have relatively uniform stresses, and because it's a relatively muddy zone, it's typically going to have a significantly higher stress than the sands below.
And so you're not relying on the continuity of any single mudstone in there but more on the fact that it's a muddy sequence.
Q Okay.

A And that whole sequence will have a higher stress.
Q Okay. That's helpful, and that might actually be a good segue, then, to my next question, which is at page 191. I'm referring to page 191 of Exhibit 30.02, and I think it's Figure 3. It's the stress gradients.
So --
A Yes.
Q -- my question is: When I look at this, it appears to me that in some -- let me phrase it this way. What is a -- what magnitude of difference in stress gradients is required or do you look for to then be able to say you've got an effective barrier to fracture propagation?
A I would say -- and I don't think there's any magic number here, but I would say at least half a megapascal or -- and so -- or half a kPa per metre, sorry -- would be a barrier.
And so -- and what happens is -- and -- and the fracture will rise. It'll encounter that barrier, and then it'll start to -- to spread laterally. And in particular with these fractures, which are -- they're water-driven fractures. They're steam-driven infrastructures. There's this trade-off between how far they can grow, and yet they're limited by the leak-off into the formation.
So the amount of fluid injected into the fracture

all ends up leaking off into the formation, and the fracture can only grow large enough to accommodate that leak-off. Okay? And so -- so when you hit a barrier, even a small barrier that -- in a reservoir like the McMurray sands causes the fracture to -- prefer to move sideways rather than upwards, then that really has an effect on limiting the fracture because of the combined leak-off and stress mechanism.
Q Okay. Thank you.
THE CHAIR: I'm crossing off all of the rest of my questions. Those are all my questions. And so now I have a couple of questions not for the -- for the Canadian Natural witness panel. So we have the one undertaking.
You were asked to have time over break, Mr. Iannattone, to deal with one of my questions.
And then I have a question -- Ms. Berg, are you going to be putting up a rebuttal witness panel?
MS. BERG: Yes. We do have some rebuttal evidence for after lunch, so the witnesses will be ready to go.
Madam Chair, I also wanted to note. You had earlier been looking at Exhibit 2.01, the -- and it was PDF 139, an excerpt from the IHS Markit report.
THE CHAIR: Yes.
MS. BERG: And so if we -- we did scroll

up, we -- I have the page in front of me now -- that material was from AER Application 1712215 Kirby expansion project application December 2011 supplemental information request to March 2013 response.
So I just wanted to clarify that for the record. It is CNRL material, but it's drawn from the -- the Kirby expansion project application.
THE CHAIR: Okay. Thank you very much. That's helpful to myself and to Canadian Natural. I appreciate that.
So we'll take a break for lunch, and then when we come back, Canadian Natural, do you have a response to that question? We can hear it, and then, Ms. Jamieson, you have an opportunity for any redirect, and then we will go to rebuttal evidence, if that works for everyone. Is that -- yeah? Are you nodding?
MS. JAMIESON: Yes, it does. Thank you.
THE CHAIR: Okay. So if we break till 1:15, will that give everybody enough time? Okay. So we are adjourned until 1:15. Thank you.

PROCEEDINGS ADJOURNED UNTIL 1:15 PM

Proceedings taken Via Remote Video

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October 15, 2020 Afternoon Session

C. Low The Chair
C. McKinnon Hearing Commissioner
B. Zaitlin Hearing Commissioner

S. Poitras AER Counsel
A. Hall AER Counsel
D. Campbell AER Staff
S. Botterill AER Staff
L. Chen AER Staff
E. Galloway AER Staff
S. Harbidge AER Staff
T. Rempfer AER Staff
T. Turner AER Staff
A. Shukalkina AER Staff
T. Wheaton AER Staff

L. Berg For ISH Energy Ltd.
S. Hryciw

J. Jamieson For Canadian Natural Resources Limited

A. Vidal, CSR(A) Official Court Reporter
S. Howden, CSR(A) Official Court Reporter

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(PROCEEDINGS COMMENCED AT 1:17 PM)

THE CHAIR: Good afternoon, everyone. Again, I'm scanning my screen. So I see we've got both counsel.

Mr. Iannattone, your panel -- for some reason, I have this feeling that we might be missing someone, but maybe it's just the different -- there we go. I was right. Whenever you're ready.

Response to Undertaking by Canadian Natural Resources Limited

MR. IANNATTONE: Okay. Madam Chair, I have a question for you regarding the undertaking. We have a verbal answer that we could provide now, or if you'd prefer, we could actually update -- we made a mathematical error in Tab 15B, the depth summary, so we can give a verbal answer now, or we can update that table and submit it later this afternoon.

THE CHAIR: So I think the Tab 15B would've related to Ms. Berg's question; is that right?

MR. IANNATTONE: That's correct.

THE CHAIR: What would your preference be, Ms. Berg?

MR. IANNATTONE: I would prefer to do it verbally now.

THE CHAIR: Sorry. I was asking Ms. Berg what her preference would be.

MR. IANNATTONE: Oh, I'm sorry.

MS. BERG: Yes. And I have -- I have no issue with Mr. Iannattone providing a response right now. I think it would be helpful as well just for the record if the correction could also -- a written correction could also be submitted, but, yes, no issue with having the provision of that answer now.

MR. IANNATTONE: Okay. So we'll start with that with Mr. Thomsen.

THE CHAIR: Okay.

A MR. THOMSEN: Okay. So we'll start with Exhibit 48.02 and page 1066, so the tab is 15B. And there -- my understanding is there's two questions here. The first one is: Why are the injectors shown with a -- at a lower depth than producers? So as Mr. Iannattone mentioned, there was -- there was a simple calculation miss between the injectors and producers. For SAGD trajectory planning, the producer trajectories are planned out carefully, and we don't -- so we don't create injector trajectories because when they're drilled, they're arranged off of the producer.

So the -- the shallowest well on KN06 would be KN06 1 injector, and so the trajectory that's planned

for the KN06 1 producer -- I have it in front of me -- this -- this trajectory from November 2019, the true vertical depth at the total of this well. So the total depth is 489 metres TBD from the kelly bushing, and so that is consistent with Tab 15B.

And so the -- the simple calculation miss was 5 metres was added for the injector, and, instead, 5 metres should be subtracted. So the correct total depth for the KN06 1 injector or 1I is 489 metres minus 5, so 484 metres is the -- is the correct value. And so this would carry forward for all of the injectors on the pad, just -- they should be 5 metres above the producer. So that is Part 1, as far as what's going on with this seeming backwards depth here, is the producers do have the correct depths listed, and it was just the injector true vertical depths; that simple mistake was made.

So I believe the second part of the question is: Reconcile the difference between Tab 15B and -- and then the CNRL opening statement. There is a slide that shows the 477-metre depth for the stress profile. I don't have the exhibit number handy, off the top of my head, or the tab number, but --

MS. BERG: I believe it's 80.02.

THE CHAIR: The opening statement? It's 88.02, I think, for --

MS. BERG: Sorry. Sorry. Thank you.
MR. THOMSEN: Okay. So, then, as far as the stress profile, there is a calculation using a depth of 477 metres, so it fits the units. If we look, Tab 15B has units of metres true vertical depth from the kelly bushing. And for the geomechanics evaluation, we want to be accurate; we want a tight evaluation. So we used a depth from ground level, so metres from ground level, and that is included in our July 3rd, 2020, Canadian Natural written submission where we outline that.
And so Tab 15B, KN06 1I, the shallowest point of all KN06 wells is 484 metres from the kelly bushing. We have a kelly bushing to ground level difference of 7 metres. So if we take that 484 metres minus 7, we end up with 477 metres TBD from ground level.
So I believe that answers both those questions, but was that clear?
MS. BERG: Yes. Thank you very much, Mr. Thomsen.
And I don't have any follow-up questions, Madam Chair.
Alberta Energy Regulator Panel Questions Canadian Natural Resources Limited
MR. IANNATTONE: Okay, then. I'd like to ask Mr. Lavigne to answer the Panel Chair 's final question.

MR. LAVIGNE: Thank you, Mr. Iannattone.
A MR. LAVIGNE: Madam Chair, could -- could I get you to just sort of reframe the question just a little bit for clarity. I just want to make sure that I'm -- I'm speaking to the issues that -- that you raised. I was a little bit confused when I saw the passage.
Q THE CHAIR: So my question was -- so it was the -- the passage that talks about: (as read)
The lateral extent of the IHS units has been estimated and modelled, and operational issues will arise due to the uncertainty with the effective vertical and horizontal permeability encountered.
So -- and then it's -- I believe it went on to talk about the potential for -- potentially a requirement of further modelling. So my -- when I read that, what I was wondering is: Are the operational issues and the modelling relating solely to the reservoir development and steam chamber, or is that -- are there broader, I guess, implications for that in respect of containment of the steam?
A Okay. Thank you for the clarification.
So to -- to address that -- and perhaps you've given me a little bit of latitude to provide some context to the question -- when the -- the -- the --

when the SIR was submitted, Canadian Natural had started up the development at Kirby South, but it was still early days, and we didn't have a lot of operational data back from that time.
And one of the things that we learned -- and in the -- in the paragraphs that you mentioned in that Markit citation, they -- they talked initially about breccia, and -- and then they moved to IHS.
So one of the things we learned really early on in -- in the development at Kirby South was that breccias can -- can be a problem, and they can become barriers to steam. And breccias were a factor in the AB/12-04 well that was referenced in the -- in the passage, and we learned -- we learned from operational data in Kirby South that we experienced nonconformance issues and poor start-up due to the fact that there were breccias in and around the injector producer level. And that necessitated redrilling some well pairs to -- to get the steam chamber to get growing effectively.
And as the economics of a SAGD project require, you know, fairly quick start-up, we -- we learned -- we learned some important lessons about geological heterogeneities. So after that, in the spirit of continuous improvement that -- that is an important core value to us, we substantially modified the Kirby

North IDA. And because of the heterogeneities that are described, we actually modified the drainage boxes, and there's no well pair in the -- in the region tested by the AB/12-04 well. So in -- in that well, probably a bigger problem was not the 1-metre mud bed that was referenced in that passage, but it turned out that overlying that area, there was about 18 metres' worth of mixed to muddy IHS, and we realized that that was not a reservoir. That is now -- and in the context of this hearing, that's what we classify as "post B2 non-reservoir," and we -- we know from -- now from more recent operational experience that we can't get steam rising into that unit, and so the drainage box boundaries in KN02 were modified to avoid encountering that -- that particular feature.
Speaking specifically to IHS beds referenced later in the passage, we -- we realized that lower down in the reservoir, down near injector producer level, the higher energy, sandier deposits that we discussed earlier in the hearing, they do not have the same lateral extent. It's once we get higher up into the reservoir and we start encountering the thicker, muddier beds that -- that we -- there -- the issues about -- from an economic point of view, that's why the steam -- the steam chamber stops there, and we no longer consider that reservoir.

So after starting up the Kirby South, we learned a lot about -- about what constitutes reservoir and what will hold back steam chambers. So the modelling, I believe, referenced in that passage refers to the -- the geostatistical model, and we use that to help forecast tight curves and things like that. So I don't think that we -- I don't think that we would rerun that model in the absence of new data, but it's made us much more aware of where potential boundary conditions exist for reservoirs.

I'm not sure if that fully answers your question, Madam Chair.

Q It does. Thank you.

A Okay.

THE CHAIR: So, Ms. Jamieson, the panel is yours for any redirect.

MS. JAMIESON: Thank you, Madam Chair. We actually -- I did have a number of questions for the Canadian Natural witness panel, but the AER staff and the Panel has actually covered all of the same ground. So I have no further questions for our Panel. Thank you.

THE COURT REPORTER: You're muted, Madam Chair, by the way.

THE CHAIR: My lips are moving, but nobody can hear anything.

Thank you, Mr. Vidal.

So let me try that again. So I think with that, I can thank the Canadian Natural witness panel for your attendance and for your answers yesterday and today, and you are now -- here's that phrase again that I don't like so much, but it is what it is. You're dismissed and free to -- to confer with -- with colleagues, counsel, et cetera.

And, Ms. Berg, you're going to proceed with some rebuttal evidence; is that the plan?

MS. BERG: We do have some rebuttal evidence, Madam Chair, yes.

So I would --

THE CHAIR: Sorry. Just --

MS. BERG: Oh, sorry. Go ahead.

THE CHAIR: So I was going to ask our -- in terms of logistics, so that means we need all the Canadian Natural witnesses to go off camera and yours to come on.

MS. BERG: So I would ask all of the ISH witnesses to -- to put their cameras on, please, and I -- if someone could let me know when that happens because I'm not seeing everyone on my particular screen. Everybody's on?

All right. Madam Chair, I would ask -- I believe that the -- the entire panel has opted to be affirmed,

so if we could proceed with that.

VERONIQUE GIRY, PETER VERMEULEN, DAVID LEECH, EDWARD MATHISON, EARL WARD, BRETT THOMPSON, JENNIFER CLEE, Affirmed

Rebuttal Evidence of ISH Energy Ltd.

MS. BERG: Thank you.

I'd like to start with Mr. Vermeulen.

Mr. Vermeulen, I understand you would like to respond to some new evidence provided by Mr. Sverdahl yesterday.

MR. VERMEULEN: Yes. I would like to respond to some of the evidence from yesterday regarding seismic interpretation.

So by way of background, in CNRL's hearing submission, a semblance slice was presented in time and created from a post-stack migrated seismic volume at an approximate mid-B1 mudstone level and was used by ISH to point out several dissimilarity anomalies on this slice. This is Exhibit 30.02, PDF 120. If it's possible to bring that up, it would be appreciated.

Thank you.

In CNRL's opening statement, they presented a different semblance slice to represent the same mid-B1 mudstone level.

Is it possible to bring up the unmarked version, which is Exhibit 49.02, PDF 1113?

THE CHAIR: Do we need the page number again?

MS. TURNER: Can you repeat the exhibit and page number.

MR. VERMEULEN: It's Exhibit 49.02.

MS. TURNER: Yes.

MR. VERMEULEN: PDF 1113. And if we could just keep both those tabs close together so that we can toggle back and forth. Great. Thank you.

So noted as the preference of the Kirby project geophysicist, this semblance slice was created from a pre-stack migrated SAP seismic volume that had been stretched to depth. This process, as CNRL noted, could cause variations due to the velocity process of converting the time-migrated version to depth.

So could we just toggle back and forth between those two just so that the Panel can see the -- the differences or the variations. Great.

So the time to depth stretch semblance slice was mostly absent of the original dissimilarity anomalies pointed to by ISH in their opening statement and instead contained noticeable smearing in a predominantly east-to-west direction.

If we could just go to the other exhibit.

CNRL went on to explain the absence of dissimilarity anomalies, and enhancement of acquisition footprint was the result of the pre-stack time migration's ability to be more focused. Focusing in seismic processing indicates that images become more clear and edges become sharper. Also, the modern processing that CNRL indicated the 2008 Kirby North 3D seismic volume had undergone is designed to maximize the seismic signal and minimize or remove noise.

CNRL's semblance slice created from the pre-stack migration that was stretched to depth saw the dissimilarity anomalies become less sharp and, by amplifying the acquisition footprint noise, made the image less clear. CNRL's argument that the pre-stack time migration tends to focus reflection events is poorly demonstrated in their depth converted pre-stack time migration semblance slice.

Without CNRL submitting more semblance slices above and below the approximated mid-B1 mudstone level created from the less noisy and arguably more focused post-stack time-migrated volume, CNRL has not clearly demonstrated that their seismic does not show subtle faults and fractures.

When asked what further interpretation steps would be taken after suspecting a fault on a semblance volume, CNRL did not suggest a simple review of more semblance slices, nor did they suggest to toggle their time horizons to display amplitude, nor would they make

use of the pre-stack time-migrated gathers to look at how amplitude and velocity varies with azimuth. Instead, CNRL has noted they would turn back to the stacked seismic sections from which the semblance was created to highlight faults for visual verification.

CNRL states in their geophysical cross-response that they would easily recognize a 7-metre displacement on seismic markers at the Wabiskaw B Paleozoic or within the reservoir itself.

I find this an extraordinary accomplishment. With 100 hertz of dominant frequency at the McMurray level in the 2008 Kirby North 3D seismic and using a velocity range from 2,500 to 2,750 metres per second, which was taken from the velocity model CNRL provided in Exhibit 49.02, PDF 1116, geophysicists can calculate the seismic wave to have a 25-to-28-metre wavelength.

With small velocity and density changes expected across a 7-metre displacement in the Wabiskaw and McMurray formations, the pertubation on this seismic wave forming would certainly be extremely small. Coupled with the expected vertical or subvertical orientation of a fault and the 2008 Kirby North 3D lateral trace spacing of 12.5 metres, the time difference between adjacent traces would be less than 3 milliseconds on a stacked seismic section.

Add to this any random or known acquisition

footprint noise that was insufficiently removed in processing and that the 2008 Kirby North 3D seismic acquisition geometry only produces 15 old data at the Wabiskaw McMurray level makes CNRL's claim of identifying faults with 7 metres of displacement on a stacked seismic section truly remarkable.

The geophysical tools CNRL chooses to interpret subtle faulting and fractures in the combining strata forego significant geophysical and data analysis advancements the industry had made in the last 20 years. Modern geophysical interpretation tools have allowed for multiple attributes to be used in combination to highlight features not visible by mere visual -- visual inspection.

That's all I have to comment on the seismic interpretation. Thank you.

MS. BERG: Thank you, Mr. Vermeulen.

Mr. Mathison, I understand that you would like to respond to some of the new evidence provided by Mr. Lavigne yesterday.

THE CHAIR: You're on mute, Mr. Mathison.

MR. MATHISON: Thank you, Ms. Berg.

I would like to respond to statements made by Mr. Lavigne yesterday in the course of evidence in cross-examination.

Would you please refer to 88.02, PDF 17. I think

we may be out. Try 16. I think we may have the wrong number here. There it is.

There's a core photograph on the right and a well log on the left of the 1AA/11-01 well. You'll notice that there is a red line in the core photograph at the bottom, lower left-hand corner labelled "non-reservoir base."

That's not the one. I think we're going to have to get -- figure out where we are in this. I think we may be -- go up one more, please. Yes. This is -- this is the correct one. Sorry. My apologies.

You'll notice that the -- on the lower left-hand corner, we have a red line marking "non-reservoir base."

And now if we'll go to PDF 18. I'm hoping this is correct. Yes, this is correct. What we're seeing, really, is just an expanded view of the core, adding core both below and above. The interval showed is illustrated on the overlying well log. CNRL neglected to mark the top of the reservoir which occurs at the base of the core that is just above the 'R' in "hearing." So in the caption below, if you'll go to "Canadian Natural hearing," it's right above the 'R'. So that's where that red line, the base of -- of non-core or non -- non-oil -- or non-reservoir is in that well.

Without knowing this -- that this -- without knowing this, it would be difficult to state precisely where the top of this thick, sandy IH -- without -- pardon me. Without knowing this, it would be difficult to state precisely where the top is, where the top of the reservoir is, as there are thick, sandy IHS above the boundary, and we can see just above in -- just above the 'R' and just above the 'G', we have some beds that are in several decimeters thick whereas we see below the boundary -- let's say just above the 'T' -- we have some thin beds in there and certainly thinner than what we're seeing above the boundary.

In -- in the Fustic, et al. -- and this is 30.02, PDF 95, and this is -- this was information that was presented by CNRL, and looking at the second paragraph, the first sentence -- I don't believe this is it. Oh, sorry.

THE CHAIR: Can you repeat the exhibit number and the page.

MR. MATHISON: Oh, yes. It's 30.02, and it's 95.

MS. TURNER: Yes. Thank you. We just have a computer-frozen issue.

MR. MATHISON: That's -- that's fine. Thank you.

And you'll notice in the second paragraph on the

right-hand side -- so it starts with "visual," and I'll just read it out for you: (as read)

Visual core investigation and log analysis cannot accurately predict the lateral extent and permeability of fluid migration and molecular diffusion through the reservoir.

And to go on, so in response to this, the picking -- the difficult of picking a precise top of reservoir, in particular where there's sandy IHS, is illustrated in their Exhibit 02.01, PDF 29. If we refer to that, please.

Yes. Thank you.

And this is what they used in the modelling. Where the sandy IHS, according to their modelling input, it clearly goes up to just below the lower B1 boundary, we can see that in the 05 -- 1A -- is it "1A"? I can't read it off the screen. It's the -- the well at the far left-hand side and, to the certain extent, the next well over also.

This is much higher than the previous well, so the 11 -- the AA/11-01 well that we just looked at previously. Therefore, the pick of the top of the reservoir is inconsistent and cannot be considered as a continuous unit.

Since the -- and this is moving on. Could I get you to bring up Adams. And this is a part of the CNRL

submission, 88.02, PDF 19, and this is in gas chromatography-mass spectroscopy. That's correct. That's it. You'll notice that the chart in the left-hand corner is from Adams 2008.

And with regards to this, CNRL has chosen to interpret the GC-MS -- oh. They have chosen -- oh, sorry. Pardon my -- okay. They have chosen to use -- they have interpreted their GS -- GC-MS data in a manner consistent with Adam -- Adams 2008. In fact, you would see that it's very similar to the chart of -- the four charts at the bottom of Adams. It's very similar to the chart that's farthest to the right, which is Image D.

Now -- and moving on, they have chosen to ignore revisions made by Fustic, et al. -- and, of course, Adams was one of the authors in this -- which are -- and this is based on data from the joint venture Athabasca sands project. It's a joint venture between Nexen and -- I forget now. Sorry. My apologies.

Anyways -- so could we go to the Fustic, et al. 30.02, PDF 92. Perhaps it's -- I'll get the correct -- I have a page number 92. For some reason, ours -- so this is the 30 -- 30.02. Where is it? Oh, could you scroll down, please. Sorry. My apologies.

Now, you'll notice -- you'll notice that in this diagram, they only have three diagrams, and the one

diagram that is missing is the one that most closely approximates what we see or what the -- the compositional gradients indicate in the AA/11-01 well, and I'll show you. The one that -- one that Fustic, et al. believe is -- is the valid evidence of the barrier is the -- the -- what their chart on -- on the right, "Chart C," and you'll notice what they see is a -- the trending up to the right of the gas -- of the -- the compositional gradient, and then a kickback over top where there is a barrier so that it doesn't go straight up. It comes back.

And I'll show you an example. If you would please go to page 92. And this is right out of their work. Pardon me. Sorry. Wrong page number. Page 96, please. So it's just in this document but just down four pages.

And could you bring up -- there. And you'll notice this is based on real-world data, and you'll notice that on the left-hand side, they are interpreting barriers between the various channel units, and you'll see that the -- you can see the two gradients going over from the same position; whereas, in the Well 2, you'll see the compositional gradient goes continuously up and bends off to the right, and this is going through two channels.

And what may be of interest is that the channel on the right has 17 metres of IHS; whereas, the channel on the left has 12 metres, yet the channel on the right is the stacked channels. On the right -- pardon me, are -- they -- they are interpreting it that there's no barrier between them. So even where you have very thick IHS, you can still get communication and -- and movement of fluids through those IHS.

So to move on -- that's it for that. Now, please turn to CNRL 88.02, page 23. That's great. And could we zoom in on it a little bit. What I'm interested in -- I'll show you -- is this interval here that Mr. Lavigne looked at, and he -- yeah. He interpreted it as coring-induced fractures, saying it -- it looked like petal centre -- centreline fracture. Now, the problem that I have with this interpretation is that because the stratigraphy within this interval is virtually completely destroyed -- it -- you can't -- you know, the typical stratigraphy is what we see on either side of -- of this core interval, and so, therefore, the -- the destruction of that -- that layering had to have occurred prior to the cementation.

And -- and I think that in -- in all probability, although you can't say for certain because we do not have any geochemistry from this -- this -- this layer because the cores are gone, that I believe a more reasonable interpretation -- he -- Mr. Lavigne

interprets this as a concretion. I think it's much more likely that this is strata that has been totally destroyed by fluids that have accessed that zone along the fracture system. And, in fact, they probably had brought in the cementing medium with them, which is carbonate cement.

And the only way we can resolve this completely is to have oxygen isotope and carbon isotope data, which, of course, are not available anymore. And you'll -- if -- if this was coring-induced fracturing, we would expect to see these petal-centerline fractures to be open, and I -- I do not see -- other than maybe the centre, but I'm not even sure that's coring-induced. Perhaps it is, but -- but certainly in the overlying stuff, we do not see any -- any petal-like structures -- petal fractures coming off there, which we would expect to see.

Could I turn your attention to PDF 24, Exhibit 82 -- 88.02, please. And this is a continuation of that -- we're just down below that -- that core interval. We're down in what CNRL has interpreted as the "B2," and you'll notice the -- the base of the B2 occurs at -- right there, just to the top of the second column on the -- on the -- at the top. And the top of the B2 appears at the top of -- top of the first column.

So that entire interval between those is considered to be part of the -- pardon me, the B1 mudstone, what they referred to as the "mid-B1 mudstone," you can see there; they have labelled it as such. But the interesting thing about this is that at the bottom of this, you'll notice the black zone, the dark zone, dark grey to black, and this is a carbonaceous mudstone. Even with just core photographs, it's evident that this is a carbonaceous mudstone. This cannot be part of the B1.

You know, it -- it's -- yeah. I don't know how they can consider it that, but, anyways, we won't get into that, but certainly not. So if there's any B1 present in this well, it has to be much thinner, and, in fact, I don't -- and granted we are looking at core photographs, I don't see anything in here that -- in -- in the overlying strata, it's looking to be a mid -- medium grey mudstone, but -- but I do not see any evidence of silty bioturbated zone. So, in fact, this -- the B1 may actually -- or the B1 mudstone may actually be absent in this well, which raises serious concerns about what is happening to cause that.

May I address your attention to PDF 25, the next page, please.

Now, this is, again, one that Mr. Lavigne chose to look at. And could I direct your attention to -- to

the Number 2, the -- the close-up of Number 2, which he interprets as coring-induced fractures.

And you'll notice that at the base of this is a unit that he considers to be drilling mud. Now, it's ironic -- or it's unusual -- I have never seen it, and I've looked at hundreds of core in the Mannville and in the McMurray formation, and I have never seen drilling mud that looks like this. Drilling mud is generally the same colour as the mudstones above. It's brown -- it's a grey. This looks a lot more like the -- the sand -- and you can see at the top of one, that sand. And I think the best interpretation -- and because we have -- we don't have the core, we have to make an interpretation -- is that this is actually a sand and that perhaps even that it's -- it's competent because it's stuck together, and there may even be a fracture, and I'll give him that. This could be a drilling-induced fracture in the sand. So to go on, you know, I don't -- don't believe his interpretation of that is correct.

And, again, going to the -- can we zoom in just to the interval above the Box Number 2. So I -- I've pointed to it. We'll see if we can -- how well we can see that. We may have to bring up the -- the actual core photograph, which is -- and I don't know if I've got it. It's in the 02-01 well.

Excuse me for just one second as I look that up. My apologies. It's a -- page 39 of the annotated cores, which is 65.02. Is that correct? It's ISH's -- or CNRL's submission. 53.02, is that correct? Yeah, 53.02 -- pardon me -- and page 39, please. It's the same core. So we're in the right thing. Now we need page thirty -- 39, please. There we are. And could we zoom in on the -- I'll move the -- the -- yeah. So just this upper portion of the core, this is the -- yeah. That's good. That's probably good enough. We'll probably lose resolution here.

So this is the top of the box that Mr. Lavigne chose us -- chose for us to look at, and so we're -- what I want to point to is that this interval above hardly looks like drilling-induced fracturing. You can see in this one you do have a nice orthogonal pattern. Well, it could be drilling-induced. This one doesn't. What this one looks like is -- is more of a -- just a broken-up piece of core, and you'll notice that there is a little bit of sands in interstices between these highly broken, fragmented core mudstone fragments. And I think that -- I think that a more reasonable interpretation is that -- of this is that what we are looking at is -- in the lower part, that these are probably natural fractures and that, as we move up, the -- the intensity of fracturing has increased to the

point of complete brecciation.

Let's move on to -- okay. I would like to point out also that this is the same well that ISH presented the intense fracturing faulting, which I interpret, actually, as faulting, in the Paleozoic, and I'll give the reference -- I don't think we need to look at it -- 65.02, page 41, but you needn't go there, as well as the distorted strata in the McMurray A that Mr. Poitras referred to. And as well as that, Mr. Lavigne considered a large -- what I would -- he considered a large outsized clast. I would consider it just highly distorted mudstone beds in 88.03, page 33.

So this was all in one well. It's -- to me, that's highly unlikely that you're going to get that degree of drilling-induced fracturing in one well; whereas, you don't see that intensity, for the most part, in other wells. We do see lots of evidence of fracturing, but this intensity is really anomalous.

So moving on. And I'd like to refer to the hearing transcripts October the 14th, Volume 2, page 312.

MS. TURNER: Mr. Mathison --

MR. MATHISON: Did you get that?

MS. TURNER: You would like us to share our --

MR. MATHISON: Yes, please.

MS. TURNER: Just one moment. You said from October 14th?

MR. MATHISON: Yes. October 14th, Volume 2, page 312.

MS. TURNER: Okay. There's only 224 pages in Volume 2.

MR. MATHISON: I must have the --

MS. TURNER: You mean October 13?

MR. MATHISON: It was the cross of -- of CNRL yesterday.

MS. TURNER: Okay. So to -- from October -- sorry. From October 14th has 224 pages.

MR. MATHISON: We must have a -- I'm not sure. It is a cross on the oil water contact between the two wells, 'K' to K Prime. I'll just refer to what I have here, and we'll -- we'll sort that out. Is that okay with you?

MS. TURNER: Sure.

MR. MATHISON: Madam Chair, we'll get the exact reference there.

Let's -- could we go to Exhibit 29.02. And it's the 'K' to K Prime cross-section. It's part of ISH's submission.

MS. TURNER: Do you have a page number for Exhibit 29.02?

MR. MATHISON: There -- there's no page

number. There's only four --

MS. TURNER: Okay.

MR. MATHISON: -- four in there. Is that the 'K' to 'K'? No. That's 'A' to 'A'. I think it's the last -- I believe it's the last one in the series. And -- oh, that is 'K' to K Prime. Yes, yes. We'll look at that. And could I get you to zoom in on the far right-hand side. I know we don't -- you don't need the -- no, no. Left. Do I have the wrong reference here? Ah, yes. There we are. There's the AA/06-01 and the AA/07-01. We asked Mr. Lavigne to give us the oil water contacts in two wells, and he graciously complied.

And I would like to, first of all, take a look at the 06-01. So could we do a close-up at the bottom of the well, just the very -- very -- we don't need to see what the well is. We know what they are. So just do -- and now scroll down, please. Yeah. There we go. A little bit more, please. Thank you.

And so he -- he gave us -- he said that -- he gave us a depth of -- and this is directly from the transcript of "492 metres at a resistivity of 10 ohms." And when -- now, could we scroll over to the next well to the right, and this is the 7 -- the AA/07-01 well. When we asked Mr. Lavigne to give us an oil water depth, he responded by giving us two depths, at 498 and -- you can see that at 500 is the -- 500 is just almost right at the bottom of the well. I'll show you that. This is 500. And what Mr. Lavigne gave us was 498, which is just 2 metres above this, and he said that it could be at 498 and that -- he said that there was a saturation gradient, and he responded that it could also be as high as 493.

My pointer -- there it goes. So somewhere in there is -- is where he thinks that the oil water contact -- and I -- I would argue that -- that I think Mr. Lavigne has -- has made an error here, and if you look at this right here -- if you look right there and you go over and you read the ohms, this is -- this is our 10-ohm cutoff that he used on the 06-01 well. So that's 10 ohms, and you can see that, clearly, our oil water contact is below 500. In fact, it's closer to 501.

So if we take that information and we calculate that depth, we have KBs for both of these wells, and if you -- I don't think we need to go up and check that, but, you know, for people who would like to, they can see it on the -- on the well log. The depth for the -- the 06-01 well is -- has a KB of 681.3, and the AA/07-01 well has a KB of -- of -- oh, where is it -- six -- no. Pardon me. The AA well has a KB of 679.1 -- excuse me -- and the -- the AA/07-01 well has

a KB of 681.3.

So if you calculate out the water contacts, given the KB, it would -- the oil waters come out at -- in the AA/06 well is 187.1. So it's this well.

Now, I must -- I must, first of all, explain that this cross-section is hung stratigraphically so that it's hung as close as we can be to what it was at the time of deposition.

And so what we see in the oil water contacts is, shall we say, a fossil contact. Anyways, I'll go -- and then I'll go over to the 07-01 well, and that works out to 180.4. So we simply subtract the two, and it indicates that there is a 6.6-metre difference in the oil water contacts between these two wells.

And so from my experience on the western plains working all the way -- you know -- that's a significant offset, and although I'm not going to demonstrate it here, on other cross-sections in this area, we see those offsets not just at the Paleozoic, but we see them all the way up through the column getting up to the top of the Mannville -- close to the top of the Mannville. And in some instances, we see them at the base of fish scales. So those -- those are significant offsets.

And I'd like to quote Mr. Lavigne from the record. Now, I'll say Hearing Transcript Volume 2, PDF 172,

line 24 to 26.

And we asked if he agreed that the oil water contact will represent a near horizontal surface at the time that the reservoir was filled, to which he replied -- and this is PDF 172, lines 4 to 10 -- it must have been PDF 71, the previous one, because it was just above this. Sorry. My -- again, my apologies. To which he replied: (as read)

> I think that this is a dangerous practice, especially since in -- in an -- oil sand reservoirs, after the charge, the degradation of the oil to bitumen happens very quickly. And so, essentially, that oil contact freezes in place. Any structural movement or changes to that after the fact has the effect of bending the oil water contact.

So we're seeing what he calls a "bending" of the oil water contact, and this is a significant thing, and he also -- he mentions that structural movement can be -- and, I would argue, is the most likely cause of this.

The other thing that's of interest is this offset in elevation of oil water contact occurs at a steep gradient in the Paleozoic unconformity derived from seismic.

Now, this is -- this is their seismic, Exhibit 29.02, PDF 11. Could I see that, please.

Could we have that brought up, please.

MS. TURNER: Did you say Exhibit 29.02?

MR. MATHISON: Oh, it must be -- sorry. My mistake. 30.02, and it's PDF 11.

MS. TURNER: Thanks.

MR. MATHISON: I'm sorry. I must have the wrong number there. I'll get it for you. It's actually page one -- 118. My -- my mistake.

MS. TURNER: Of Exhibit 30.02 for the --

MR. MATHISON: That's correct. This is the one.

And I'll just point to where those wells occur. So 06-01 -- AA/06-01 and AA/07-01. There's AA/07-01, and I think this is AA/06-01 back here, one of those. Do we have a map (INDISCERNIBLE - BACKGROUND NOISE)? There. That's what I need.

It's actually between these two wells, AA/06-01 and AA/07-01. Now, this is based on seismic and, I would argue, is far less precise than -- than using well logs and -- and actually see it, and we also have the core evidence. We can tell that.

So between those two wells, we're looking at 6 metres of offset, and I've shown you another cross-section, 'W' to 'W', that we have an 11-metre offset at Paleo and 7.5 metres up here.

So, you know, clearly, their seismic is seeing something coming through there, a linear feature, with a significant amount of offset, and that is reflected not only in the Paleozoic and overlying strata but also reflected in the oil water contacts.

So this is -- this means that this feature, whatever you want to call it, whether we call it a "flexure" or whether we call it a "fault," is a late feature in that it's later than oil migration, which is considerably later than the deposition of the Mannville group and also after biodegradation. So the oil has to be frozen in place, and this is -- Mr. Lavigne has made that point already, and thank you very much.

And in -- now, this is -- I think we'll just leave it at that. Well, I'll make one comment more, and this refers back to their submission earlier, but they have tried to dismiss this as differential compaction, but the difficulty that I have with that is there are actually thicker sands in some of these wells or equivalent sands in these wells, and so I -- I don't understand where you're getting this compaction from. If you're looking at sands in the -- the -- their post B2 valley fill that are equivalent in thickness or certainly in -- and, in fact, somewhat in part thicker, I don't understand how you can expect to get that differential compaction. Anyways, that's -- that's all I have to say.

And thank you very much, Madam Chair.

MS. BERG: Thank you, Mr. Mathison.

And then, finally, Ms. Giry, I understand that you would like to respond to some of the new evidence provided by Mr. Craig and Mr. Iannattone yesterday.

MS. GIRY: Yes. Thank you.

I would like to address allegations that we have heard in this proceeding regarding ISH and the deliberate production of GOB gas.

Specifically, I want to address Mr. Craig's clear allegation yesterday and today that ISH, as the operator, shut in the 10-01 well on January 7, 2020, after having produced GOB gas. This is not the first such allegation against ISH. In its evidence filed in this proceeding in Exhibit 48.02, PDF 48, CNRL wrote about the voluntary self-report that ISH made regarding the 10-34 gas well. CNRL said -- and I quote -- "the data also provides evidence" -- that's the next page: (as read)

> The data also provides evidence that gas production from the Upper Mannville II pool may have been initiated prior to April 2019, and that production was shut in in January 2020 as disclosed in ISH's notice of noncompliance dated January 15, 2020.

For the record, ISH's voluntary self-report is on the

record of this proceeding, and I also made a correction to that self-report in my opening statement.

It seems that following the receipt of Mr. David Leech's report in this proceeding, that CNRL has now abandoned the allegation regarding the 10-34. Given that the evidence indicates that the gas had been flowing from 10-01, CNRL has changed its story. It is now accusing ISH on turning on the 10-01 well and producing GOB gas for a period of many months. The 10-01 well is monitored by CNRL and located 700 metres from CNRL's plant. It is also our understanding that the 10-01 well was manually checked by CNRL during the period when gas was flowing from the GOB zone.

These accusations are not true. ISH has not turned on production in any GOB well, including the 10-01, the 10-34, and the 16-35. We are an ethical operator. I am the COO of ISH, and I would not compromise my integrity or my long career as an engineer in the oil and gas sector by allowing my company to engage in such profoundly unethical conduct.

ISH continues to believe that there is a serious issue with the 10-01 well. That is the most reasonable explanation that fits the evidence regarding flow of the 10-01. ISH did not produce that gas.

Yesterday, Mr. Iannattone referred to the confidential and without-prejudice meetings held since

February 2020 and mentioned ISH Kirby asset/liabilities. I want to note that the licencing liability rating, the LLR, as defined by the AER, for ISH Kirby asset is around 1.7.

We understood that when we began this appeal that this would be a hard fight with an entity like CNRL on the other side. However, I never imagined that CNRL would hurl out completely unfounded, very serious accusations that are clearly aimed at ending ISH as a company as well as ending the careers of senior personnel at ISH, including me. Thank you.

MS. BERG: Madam Chair, that concludes the rebuttal evidence. The ISH panel is now open for questions.

THE CHAIR: Thank you.

Ms. Jamieson.

MS. JAMIESON: Madam Chair, may I have five to ten minutes to confer with my clients?

THE CHAIR: Sure. Let's take a ten-minute break. Well, let's take a break and reconvene at 2:45.

MS. JAMIESON: Thank you very much.

(ADJOURNMENT)

THE CHAIR: We must be getting closer to the end of the day. The message we got from Ms. Turner at this time was simply "come back," not "we're ready for you," not "come back when you're ready," just "come

back." So here we are. So, Ms. Jamieson, over to you.
MS. JAMIESON: Good. Thank you very much.
Ms. Jamieson Cross-examines Canadian Natural Resources Limited (Rebuttal)
Q MS. JAMIESON: So I do have a set of questions, and they're really just for Mr. Vermeulen. Yes. Thanks for unmasking.
So, Mr. Vermeulen, in your rebuttal evidence just now, you made a series of comments regarding Canadian Natural's seismic methodology, and I just have a set of questions to try to derive some clarity around that issue, if we could.
So the first one -- I'd like to just bring up Exhibit 89.01 from yesterday. It was ISH's Aid to Cross-Examination Number 3. Thank you.
So -- and this is not a field I'm very knowledgeable about, Mr. Vermeulen, so bear with me if I could, but I understood one of your --
MS. BERG: Sorry. One moment. Oh, there. I was just wanting the exhibit to come up. Sorry, JoAnn.
MS. JAMIESON: Thanks.
Q MS. JAMIESON: I just understood some of your comments related to some of your earlier -- some of the earlier questions that Ms. Berg had about this document. So let's just give this a try.

So, first of all, the questions that Ms. Berg were asking related to this document, I understood as relating to workflow; is that correct?
A MR. VERMEULEN: Yeah. Yeah, that's correct.
Q I think I -- my recollection is the suggestion was that Canadian Natural, you know, wasn't following the recommended workflow that came from this Attribute Studio software. Is that -- am I on the right line there?
A Well, it was just that -- the point, I guess, that ISH was trying to put across was that the Attribute Studio contains the entire workflow for advanced quantitative interpretation, and if CNRL made use of that -- that workflow was -- was really the -- the question.
Q So you weren't suggesting the actual workflow is -- this is a sales brochure. You weren't suggesting the actual workflow was in this document, were you?
A No, no, no.
Q And you could have, perhaps, provided a peer-reviewed workflow published in one of the journals that would've described the workflow?
A I suppose I could've, yeah.
Q Mr. Vermeulen, now, I appreciate just some of the confidential information requests, but I -- I don't think it's going to be a problem, but the request from the IR -- and I don't think we need to bring it up, but

we could, but our recollection was that you requested the pre-stack migrated volume. Can you confirm that?
A I did, yeah. That --
Q Right.
A The SEG-Y volume?
Q The actual data, the actual pre-stack migrated volume.
A Yeah.
Q Yes. So you requested that.
And then would you agree that, in general, that pre-stack migration data is superior to post-stack for image faulting?
A You know, in -- in general, I would agree with that statement, but after reviewing the semblance depth slice, I guess, that was created from the -- the pre-stack time migration, I would be concerned that the acquisition footprint wasn't sufficiently (AUDIO FEED LOST) in the processing, and so then I would -- I would say --
THE COURT REPORTER: Sorry, Mr. Vermeulen. Your mic cut out a bit there.
MR. VERMEULEN: Sorry.
THE COURT REPORTER: If you could --
A MR. VERMEULEN: I'll just repeat myself.
The pre-stack time migration that was used to create the semblance depth slice, which demonstrated that there was still quite a bit or even an enhancement

of the acquisition footprint, would be of concern and -- and so that's what I would say about that.
Q MS. JAMIESON: You're saying that that would be a concern, but you don't actually have any evidence; there's no evidence on the record that you could point to that in some way Canadian Natural's acquisition footprint was sufficient, can you? Is there evidence you can point to that would support that concern?
A Well, the smearing on the -- the semblance depth slice would be, I guess, the evidence that would show that there is -- you know, compared to the post-stack migrated semblance time slice, you know, the -- the acquisition footprint was -- was quite a bit more pronounced on the pre-stack time migration.
Q Okay. And then can -- I'd like to just ask you about resolution limits. How did you calculate your resolution limits?
A Well, I -- I was basing this just on a simple back-of-the-envelope calculation based on the frequency, the velocity, and the depth of -- of displacement.
Q Back-of-envelope frequency and -- sorry, what was the other part of your answer?
A So the hundred-hertz dominant frequency within the -- the Wabiskaw McMurray zone that was given yesterday, and then the velocity from 49.02, figure -- or Tab 4F,

I believe. CNRL had provided the velocity model that they -- they had used for the depth conversion. Yeah.

Q So I believe Canadian Natural actually said that the frequency for the Wab and the McMurray was 105 to 110.

A Okay.

Q Do you recall that, sir?

A Yeah. I -- I do recall that, actually, yes. Five -- like, 5 hertz would make a very minimal impact on -- on my back-of-the-envelope calculation.

Q Now, can -- are you aware of the Rayleigh -- sorry, excuse me -- the Rayleigh criterion, which I understand is a quarter wavelength?

A Yeah, yeah. Tuning effect. I am -- I am aware of that, yeah. And if you -- if you take the wavelength that I provided and you divide it by four, then that's sort of the -- the vertical resolution of the -- the seismic. This is what would be considered the absolute best-case scenario for -- for seismic or almost, like, the theoretical. Once you throw in things like acquisition footprint or -- or random noise and -- and other things that are going to disturb your signal, that changes.

Q Okay. And what about the Widess criterion resolution, the detection limit; are you aware of what that is?

A Could you clarify for me.

Q Well, my understanding --

A Is that the lateral -- like, are you --

Q Yeah.

A -- referring to lateral resolution? Yeah, yeah. Okay.

Q Yes. And what would it be? What's the limit of detection?

A You know, in -- in this case, I -- I would say that the limit of detection is your bin size.

Q The limit of detection is your bin size.

What about one eighth, the wavelength?

A Again, that would be a more theoretical and not practical calculation.

Q Have you calculated it here, the Widess criterion of the one-eight wavelength for seismic detection limit? I need some sense, sir, of what detection limits you're applying to the seismic.

A I'm -- I'm really just considering the -- the fact that your stack trace -- your stack traces are 12-and-a-half metres apart and if you had a -- the point that I was trying to -- to put across, though, is that if you had a vertical or subvertical fault, that you would -- you would really have only, you know, one -- one CDP or maybe two CDPs of -- of imaging capabilities on those faults. And so it would be really hard to detect a -- a pertubation caused by a fault on the seismic stack section, which -- in my experience, I -- you know, working in -- in the

Fort McMurray area where, you know, even with very large faulting and extreme salt dissolution and collapse, with seismic of the similar acquisition parameters and -- and almost similar depths, you know, I -- I was not able to see faults that were offset by 7 metres just by going to the stack section. I was using enhanced interpretation tools, you know, such as the semblance and such as, you know, like, this fault attribute that Attribute Studio has by a -- a different software provider.

Q Okay. So some of that's theoretical, and some of it, it sounds like you actually applied this -- this seismic data set. Would you agree with me that, generally speaking, you need a detection limit of 2 to 3 -- at least something needs to -- you have to have a detection limit above 3 metres to actually see anything on seismic? Do you agree with that? Like, I'm not hearing any hard numbers from you, so I'm trying to find out what detection limits you were applying.

A Well, I -- I'm not certain of the -- the question, actually.

Q In ISH's evidence, we understood that you were asserting that there was a 7- to 7-and-a-half-metre fault of some sort and --

A Yeah.

Q -- the question, really, to you is -- sorry. Let me just finish. The question is: Shouldn't that be showing up on the seismic lines that you were provided, if it was, in fact, there?

A No. I -- and this is what I'm -- I'm challenging, is that with -- you know, when you're only sampling that fault with a fold of 15 and with the velocities and the frequencies that -- that CNRL had given and from my personal past experience interpreting faults within the Fort McMurray area, I find it extremely difficult to detect a fault with 7 metres of -- or -- or of displacement.

Q Back to the Widess detection limit, shouldn't a 7-metre fault be imaged?

A Well, again, I -- I would go back to the fold of your Kirby North 2008 3D data set and -- and the frequency and -- and in my past experience. I -- I -- with a data set that was, like, extremely similar to the parameters with, you know, line intervals in the 100- to 125-metre range and -- and source and receiver intervals in the 25-metre range. I -- I disagree with --

Q Okay. I'll just --

A -- with the -- well, the statement that you guys could -- could image faults of 7 metres' displacement.

Q Just one moment.

A Sure.
Q Sir, just for clarity, you're saying that based on the information you received, the seismic semblances, you were -- to you, you're inferring that the work perhaps wasn't done, but that's -- that's not your -- is it possible that Canadian Natural did the work. We know this is confidential 3D seismic. They said in their submission -- they explained what the 3D seismic was all about, and they shared with you their conclusions?
A Yes.
Q So your view is not -- I just want it clear for the record. Is it possible that all that work was actually done but didn't show up in the semblance slices you requested?
MS. BERG: Sorry.
Q MS. JAMIESON: Is that a possibility?
MS. BERG: Sorry. I'm going to interject. That's a hypothetical, and -- and all Mr. Vermeulen can speak to is the evidence that's on this proceeding and what CNRL did or did not do, really. I -- I -- I don't see how having Mr. Vermeulen respond to that question gets us anywhere on such a hypothetical. If CNRL wanted to put that evidence on the proceeding, it could have.
MS. JAMIESON: Thank you.
Madam Chair, if I could try the question another way.

Q MS. JAMIESON: Mr. Vermeulen, is it possible that the work was done but that you have not observed it?
MS. BERG: And I'm going to raise the same --
A MR. VERMEULEN: Okay.
MS. BERG: -- issue. All that Mr. Vermeulen can speak to -- and -- and -- is the evidence that he saw in this proceeding. Maybe we need a ruling on this issue.
MS. JAMIESON: No, that's fine. I'll move on. Thank you.
Q MS. JAMIESON: Mr. Vermeulen, do you agree that significant erosion at the Paleozoic unconformity has taken place at the KN06 box?
A MR. VERMEULEN: Do I agree with that?
Q Yes. Based on the evidence that you have reviewed.
A Based on the evidence that I've reviewed -- and -- and really I've -- I've only looked at the seismic data in -- in great detail -- I would say that it's plausible, yeah.
Q And do you agree that there's structural variations at that unconformity as a result of this erosion?
A I would say that that's a plausible interpretation too, yes.

Q Do you agree that erosion is a more likely explanation for the structures that are observed rather than the faulting?
A Well, I think that in order to comment on that, I would go back to what ISH had requested or even suggested in their response to CNRL's submission. It was that, you know, the semblance slice does show discontinuities on it, and, you know, semblance is -- is calculated to show subtle structural and stratigraphic features that, you know, maybe the interpreter can't readily pick up visually.
And so ISH had suggested that CNRL provide slices above and below the mid-B1 mudstone level and -- and instead CNRL had decided to switch the domain to a depth domain and use a different volume, and -- and it just kind of -- to me, it -- it was a simple request, and -- and it -- it -- so without that evidence, I don't think I could -- I could concretely confirm that it isn't structured.
Q Okay. Thank you.
So a couple last questions. It sounded like you did agree or confirm that you were able to see erosion, but you were unable to see faulting. It's just confusing that --
A I didn't give confirmation of faulting; right? So the -- the -- the semblance slices, if they were to have been provided above and below, those discontinuities that we saw within the KN06 drainage box and outside would've had a lateral and a vertical extent, and if they terminated quickly, then -- then we could conclude that -- that the -- the faulting or fracturing was -- was unlikely. If -- if we did see these discontinuities continue with some extent, then -- then I would lean to a more structural interpretation.

Q I -- I may have a -- what about on the seismic line? If I asked you that question again, were you able to see erosion but you did not see any faulting on the seismic line, for one?
A Well, here, again, is -- is -- you know, I would say that the -- the person with the most information has -- has the ability to make the correct interpretation, and having just two single cross-sections going north-south and east-west probably isn't enough to -- to make a correct interpretation.
Q Okay. Thank you, Mr. Vermeulen. One last question.
Do you agree that this VVAz and then VAVz [sic] seismic interpretation techniques are really controversial at best in the geophysical industry right now?
A You know what? I -- I didn't actually read the paper that was -- that was mentioned today, but, of course,

you know, I'd say most new-ish seismic interpretation techniques are -- are, you know, start off as controversial and -- and because they haven't been tested thoroughly enough, and -- and that's just the nature of, you know, professionals. Some like to use tools that they are familiar with and -- and some like to play with their data set with new tools.
Q Okay. Okay. Sir, thank you very much, and I appreciate your patience with my questions.
MS. JAMIESON: Madam Chair, I think that's all we have for the ISH panel.
THE CHAIR: Thank you, Ms. Jamieson.
Ms. Hall or Mr. Poitras, do AER staff have any questions for the ISH rebuttal panel?
MS. HALL: Thank you, Madam Chair.
Yes. I have just a few questions. The first would be for Mr. Mathison.
Alberta Energy Regulator Staff Questions ISH Energy Ltd. (Rebuttal)
Q MS. HALL: Mr. Mathison, with the exception of the B1 and A2 mudstone intervals, both ISH and Canadian Natural interpret heterolithic and mudstone units compromising the B2 valley fill or post B2 valley fill and heterolithic and mudstone units within the B1 sequence to be deposited in relatively shallow point bar and tidal flat settings respectively.

Can -- my question for you is: Can mudstone facies in these depositional settings become fractured and/or brecciated by processes other than faulting such as pedogenic alteration?
A MR. MATHISON: Yes. Yes, they can. And I -- I don't deny that. What my issue is, that the pervasiveness of these fracturing and not just in the units that are close to this -- you know, close to subaerial are -- are also fractured and often in the same wells. So I think based on that, the -- the -- the weight of the evidence is that -- that these things have probably -- probably represent fractures.
And, you know, I -- I'm certainly willing to admit in a few cases they -- you know, they may be related to that, and I have considered that.
Now, the one thing I do -- I disagree. I don't agree with CNRL in their interpretation of the -- the upper B1, what they consider upper B1. I suspect it's more likely a bay fill -- bay-fill succession that -- in that it overlies -- it overlies a flooding surface which has created -- and there is the creation of accommodation space which gets taken up.
So it's a very brackish -- brackish deltaic units, bay-filled deltas. So -- and -- and you can get things -- you can get slump and rotation of stuff, and I agree that -- with that.

But some of the other stuff, the -- that -- what I would interpret to be shattering -- almost a shattering of -- of some of these intervals, I don't think so.
And the other thing that -- that's of interest is if you look at -- there's a whole number of things that would indicate that we've had fluid flow going through those what I have interpreted to be faults or whatever -- fracture systems, and that -- that this has led to cementation in the basement in -- in the McMurray formation just overlying the -- the Paleozoic but has also led to cementation up as high as -- I have -- I have witnessed it in actually the 15-02 well.
It's incredibly compelling evidence that there's fracturing all the way up to the Wabiskaw and that we've had fluid flow that has -- has resulted in -- in cementation up there in -- in highly disruptive strata.
So I -- you know, to go back to that, I -- I -- yes, I would admit, and the problem -- part of the problem is we're -- we're dealing with -- with pictures. Had we had the core, some of these things could easily be resolved. But I -- I think that the vast majority of them do represent fractures.
Q Okay. Thank you.
A Thanks.
Q And just a quick follow-up question. Is it possible -- would you say that it's possible that any of the

cementation could result from migration along permeable pathways?
A Well, yes, certainly, it -- it would be. I think that the question that I -- I tried to raise was that without te geochemistry, the oxygen isotope or the carbon isotope, we can't say for certain, you know, where this -- where these fluids are coming from. I mean, it -- it -- to me, it would -- would appear to be not obvious but -- but a reasonable interpretation that they are coming out of -- out of the Paleozoic given that it's a carbonate unit and -- and the McMurray formation.
The only other thing that I can think of in the McMurray formation is -- I don't know. You know -- you know, so there doesn't seem to be a source -- a local source for -- for -- for carbonate within the actual strata of the McMurray formation.
Now, I want to -- I have actually worked with this data, and I've -- I've actually been a co-author on the Wabiskaw B, and it was very useful. We were able to determine that the -- what some people consider to be concretions, and -- and we could, in some instances, demonstrate that these were actually layers -- were marine-sourced. The carbonate was marine-sourced, and the temperature would indicate that it was subaerial exposed.

So -- so you have to think of the source. Where is your source of the elements? And then what are the pathways that these -- these elements can move into that formation? And I think the most recently -- reasonable interpretation is they probably come from the Paleozoic going up into the overlying strata, probably coming in along the fracture systems as we see in the 02-01 well.

And -- and -- and -- and so I -- you know, I -- I do believe that is it, but I can't prove that because we do -- do not have the core evidence and the geochemistry to -- to demonstrate that with -- with certainty.

I think -- I believe -- have we frozen?

THE CHAIR: Ms. Hall, are you --
MS. HALL: I'm having some definite connection issues.
THE CHAIR: Okay.
MS. HALL: I -- I --
MR. MATHISON: Did -- did you hear that?
MS. HALL: I -- some of, I think. I think the people who needed to hear have -- our staff has heard.
MR. MATHISON: Yeah. Okay. Thank you.
MS. HALL: Thank you for that.
MR. MATHISON: Yeah. Thank you.

MS. HALL: Okay. So those are my questions for you, Mr. Mathison. Thank you very much.
MR. MATHISON: Yes. Thank you.
MS. HALL: And then I do have some questions for Mr. Vermeulen, please.
Q MS. HALL: Mr. Vermeulen, you mentioned some differences -- or you had spoken about some differences between the two semblance maps provided by Canadian Natural, and I believe those are at Exhibit 30.02 at PDF page 120.
MS. HALL: And, Ms. Turner, no need to bring these up. I think we were just -- just looking at them recently so -- but this is just for the record.
Q MS. HALL: And also at Exhibit 49.02, PDF page 24.

And we note that the colour scales used to demonstrate semblance in these two maps are not consistent between the post-stack time migration semblance and the pre-stack time migration semblance maps.

So if -- my question is: If both maps were presented using a consistent colour scale, say, the colour scale used for the post-stack migrated version, how would the two maps compare?
A MR. VERMEULEN: Well, I -- I did notice the same discrepancy in the colour scales, as you had --

had noticed as well, and I believe that the depth converted semblance slice is actually a shift to the -- to the whiter side, and so that it maybe that the features would have been diminished just because you would expect those dissimilarity features to come out the same. But because the pre-stack migrated volume has such a strong or dominant footprint, that kind of overrides it.

But the other thing that is of a concern and I need to point out is that one's in depth and one's in time. And so the -- I guess the processes is what you stretch your -- your -- your seismic traces from the time domain to the depth domain. It can also cause distortions in your volume. In this case, it would be a semblance volume.

So I'm -- I -- I almost have to say that I -- I can't answer your question, is what it would look like, because they're apples compared to oranges, essentially, is -- is what it is.
Q Thank you, sir. And just one moment, please.
MS. HALL: Those are my questions. Thank you, Madam Chair.

And thank you, Mr. Vermeulen.
THE CHAIR: Thank you, Ms. Hall.

Commissioner McKinnon or Commissioner Zaitlin, any questions for you?

MS. MCKINNON: None from me.
DR. ZAITLIN: None from me. Thank you.
THE CHAIR: And none here either.

So I think that means that I can thank the ISH rebuttal evidence panel for their time this afternoon and let you know that you are now dismissed.

And that brings us to the end of the day today. Tomorrow we are scheduled for closing argument starting at 9. I think we are expecting one written filing later today to complement information that we had orally on the record this afternoon. And, otherwise, as far as I'm aware, that's it.

Ms. Berg or Ms. Jamieson, is there anything that I'm missing or anything we need to deal with before tomorrow?
MS. JAMIESON: No further comments from us, and we will -- I assume we can just file that updated table as part of our undertaking response through Ms. Turner. Would that be --
THE CHAIR: Yes.
MS. JAMIESON: -- appropriate?
THE CHAIR: -- please. Yeah.
MS. JAMIESON: Okay.
THE CHAIR: That would be appropriate, yeah.
MS. JAMIESON: We'll do that.

MS. BERG: And -- and nothing from us either. Thank you.

THE CHAIR: Okay. Thank you.

Thank you. Well, then, we are adjourned until 9 tomorrow morning. Thank you.

PROCEEDINGS ADJOURNED UNTIL 9:00 AM, OCTOBER 16, 2020

CERTIFICATE OF TRANSCRIPT:

We, Andres Vidal and Sarah Howden, 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 15th day of October 2020.

______________________________.

Andres Vidal, CSR(A)
Official Court Reporter

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Sarah Howden, CSR(A)
Official Court Reporter