2021 ABAER 001

Alberta Energy Regulator

Canadian Natural Resources Limited

Regulatory Appeal of Amendment Approval 11475EE for Canadian Natural Resources Limited's KN06 Box at Kirby North In Situ Oil Sands Development

January 13, 2021

Alberta Energy Regulator
Decision 2021 ABAER 001: Canadian Natural Resources Limited, Regulatory Appeal of Amendment Approval 11475EE, Kirby North

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Abbreviations

AER	Alberta Energy Regulator
APEGA	Association of Professional Engineers and Geoscientists of Alberta
BHP	bottomhole pressure
DFIT	Diagnostic Fracture Injection Test; initialism trademarked by Halliburton
EUB	Alberta Energy and Utilities Board
FCP	fracture closure pressure
GCMS	gas chromatography–mass spectrometry
GOB	gas over bitumen
H_2S	hydrogen sulphide
IHS	inclined heterolithic stratification
kPa	kilopascal
MMcf	million cubic feet
MOP	maximum operating pressure
MPa	megapascal
OGCA	*Oil and Gas Conservation Act*
OSCA	*Oil Sands Conservation Act*
REDA	*Responsible Energy Development Act*
RGS	EUB-initiated regional geological study of the Athabasca area of the Wabiskaw-McMurray deposit
SAGD	steam-assisted gravity drainage

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Regulatory Appeal of Amendment Approval 11475EE for Canadian Natural Resources Limited's KN06 Box at Kirby North In Situ Oil Sands Development

Decision

[1] The Alberta Energy Regulator (AER) varies the decision to approve Canadian Natural Resources Limited's (Canadian Natural) application 1909395 and issue the amended approval 11475EE (the amended approval) by way of additional conditions summarized in appendix 2.

[2] In reaching its decision, the AER considered all relevant materials properly before it, including the evidence and argument provided by each party. Accordingly, references to specific portions of the evidence in this decision are intended to assist the reader in understanding the AER's reasoning on a particular matter and do not mean that the AER did not consider all relevant portions of the evidence.

Introduction

Application and Request for Regulatory Appeal

[3] On May 11, 2018, Canadian Natural filed application 1909395 under the *Oil Sands Conservation Act* (*OSCA*) to amend scheme approval 11475 for the recovery of crude bitumen from the Wabiskaw-McMurray deposit by adding a seventh steam-assisted gravity drainage (SAGD) box at surface location 01-075-09W4M (the KN06 box) to its Kirby North project. The proposed amendments related to bitumen extraction from the McMurray Formation, drainage box location, well pad design, and well placement, intended to maximize bitumen recovery using SAGD technology.

[4] ISH Energy Ltd. (ISH) holds petroleum and natural gas rights overlying but not including oil sands in the Kirby North project area. On June 7, 2018, ISH filed a statement of concern on application 1909395. On January 24, 2019, the AER approved Canadian Natural's application without holding a hearing and issued the amended approval.

[5] Approved operations in the KN06 box are for recovery of crude bitumen from the McMurray Formation using SAGD well pairs with steam only as the injection fluid. The bottomhole injection pressure would not exceed 6 MPa (gauge), except during the start-up phase, when Canadian Natural may have a bottomhole injection pressure of up to 7 MPa (gauge) for a maximum of 14 days.

[6] On February 21, 2019, the AER received ISH's request for regulatory appeal 1927181 of the amended approval under Part 2, Division 3 of the *Responsible Energy Development Act* (*REDA*).

[7] After a written process involving several rounds of submissions, on February 11, 2020, the AER granted ISH's request for regulatory appeal. The appeal was subsequently set down for hearing as proceeding 397.

[8] On March 20, 2020, the AER issued a notice of hearing for proceeding 397. The notice stated that the AER would hold a hearing to consider a regulatory appeal of Canadian Natural's amended approval. The notice also stated that Canadian Natural, ISH, and AER Regulatory Applications (Regulatory Applications) were parties to proceeding 397. Regulatory Applications provided responses to information requests from the other parties but did not participate in the oral hearing.

[9] The AER held an electronic hearing via Zoom for proceeding 397 before hearing commissioners C. Low (presiding), C. McKinnon, and B. A. Zaitlin (the panel), which started on October 13, 2020, and ended on October 16, 2020. Those who appeared at the hearing are listed in appendix 1.

Framework for the Regulatory Appeal

[10] Pursuant to section 41(2) of *REDA*, our task is to determine if we should confirm, vary, suspend, or revoke the AER's decision to approve Canadian Natural's application 1909395 and issue the amended approval.

[11] Canadian Natural made its amendment application pursuant to section 13(1) of *OSCA*, condition 15 of the scheme approval, and *Directive 078* (now *Draft Directive 023*). In its amendment application, Canadian Natural identified ISH as a petroleum and natural gas rights holder in the KN06 box and offsetting area. ISH and Canadian Natural are partners in a Wabiskaw B gas well at 10-01-075-09W4M (the 10-01 well) that is designated as part of the Kirby Upper Mannville II Pool (the AER's designation for the Wabiskaw B natural gas pool in the Kirby North area). Canadian Natural said it would notify ISH and provide ISH with a copy of the amendment application.

[12] Figure 1 is a map showing the relative locations of the KN06 box, the 10-01 well, and the Kirby Upper Mannville II Pool.

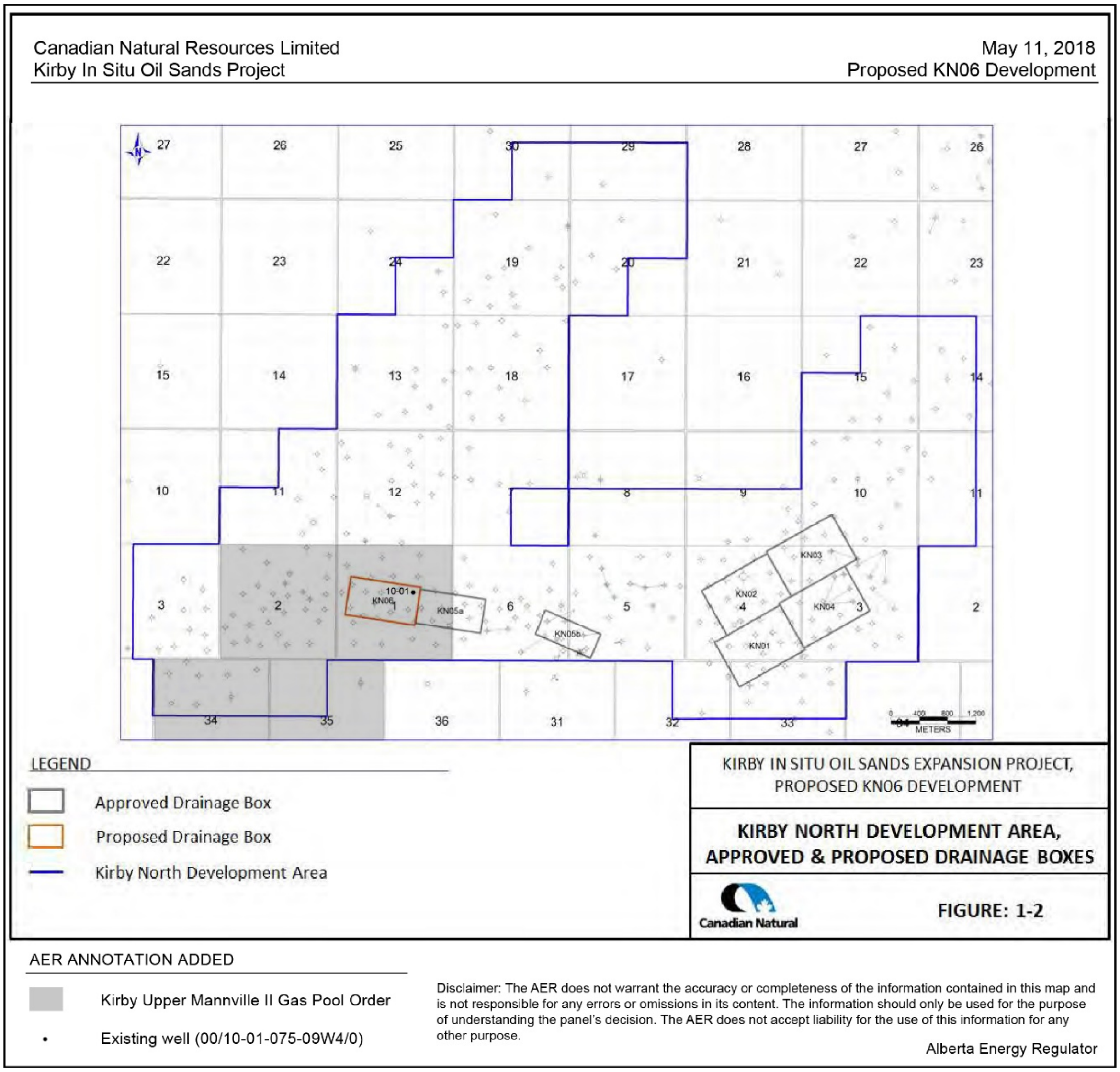

Figure 1. Kirby North KN06 Box and Kirby Upper Mannville II Gas Pool. The map above was originally submitted to the AER by Canadian Natural in its May 11, 2018, *Application No. 1909395 to Amend Alberta Energy Regulator Approval No. 11475W* (original figure title: Figure 1-2 "Kirby North Approved Development Area with Approved and Proposed Drainage Boxes"). The panel added annotations to the map to include the Kirby Upper Mannville II Gas Pool order and the location of the existing 00/10-01-075-09W4/0 well.

[13] ISH based its request for regulatory appeal on the grounds that the amendment granted to Canadian Natural could have an adverse effect on ISH's interest in the natural gas resource that overlies the KN06 box. On February 11, 2020, the AER granted ISH's request for this regulatory appeal, saying:

> The AER is satisfied that ISH has demonstrated it may be directly and adversely affected by the issuance of the Approval. ISH holds the petroleum and natural gas rights directly above the KN06 development area. ISH has provided information that indicates there is some risk of Canadian Natural's operations at the KN06 Pad interfering with ISH's rights to the natural gas in the drainage area. In particular, there is a risk that the approved start-up injection pressure will fracture the McMurray shale and Wabiskaw GOB [gas over bitumen] zones overlying Canadian Natural's bitumen, resulting in direct communication between the McMurray sand and the GOB zone. Such communication could impair ISH's ability to recover the gas in the GOB zone.

[14] The legal framework informing our decision consists of legislation, regulations, rules, directives, case law, and previous decisions of the AER.

Relevant Legislation and Directives

Oil Sands Conservation Act and the *Oil Sands Conservation Rules*

[15] The following purposes of *OSCA* are set out in section 3 of that act:

- "to effect conservation and prevent waste of the oil sands resources of Alberta";
- "to ensure orderly, efficient and economical development in the public interest of the oil sands resources of Alberta"; and
- "to ensure the observance, in the public interest, of safe and efficient practices in the exploration for and the recovery . . . of . . . crude bitumen. . . ."

[16] Section 13(1) of *OSCA* gives the AER the authority to amend a prior scheme approval on application or on its own motion.

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

Draft Directive 023: Oil Sands Project Applications

[18] *Draft Directive 023: Oil Sands Project Applications* (*Directive 023*) replaces the September 1991 edition of *Directive 023* and the December 2010 edition of *Directive 078: Regulatory Application Process for Modifications to Commercial In Situ Oil Sands Projects*, which were rescinded by *Bulletin 2020-09*.

[19] *Directive 023* sets out the requirements for oil sands applications, including amendments to scheme approvals. Section 10 of *Directive 023* describes three different amendment categories and the information that must be provided for each. According to AER *Bulletin 2020-09*, the application requirements in *Directive 078* were incorporated in section 10 of *Directive 023*. The current categories are the same as those that were in effect when Canadian Natural filed its amendment application.

[20] Canadian Natural filed its application as a Category 2 amendment. It stated that the application was consistent with an AER *Directive 078* Category 2 amendment because, among other things, "the proposed changes do not adversely impact other mineral rights owners."

[21] *Directive 078* describes Category 2 amendments as

> applications submitted to modify an oil sands project that may adversely or beneficially affect resource conservation and/or involve significant process modifications. <u>Category 2 project amendments are not, however, expected to directly and adversely affect the rights of stakeholders, including other mineral rights owners</u>. . . . [emphasis added]

[22] The directive lists examples of modifications to a development that typically fall under Category 2. This list is described as not exhaustive. It is important to note that the provision directs the reader to consider the examples in the context of the description provided in the previous paragraph in the directive. The relevant example in this case is "expanding the development area within the project area."

[23] Category 3 amendments are

> applications submitted to modify an oil sands project that may adversely or beneficially affect resource conservation, <u>directly and adversely affect other mineral rights owners</u>, and/or result in an adverse and material change to the environmental and socioeconomic impacts assessed in the original and/or any approved amendment applications and therefore, may directly and adversely affect other stakeholders. [emphasis added]

[24] Examples of modifications to a development that typically fall under Category 3 are listed, and the examples must be considered in the context of the description provided in the previous paragraph in the directive. The relevant example in this case is the same as above.

[25] The evidence on the record in this proceeding suggests to us that Canadian Natural should have made its application as a Category 3 amendment. This regulatory appeal allows the AER, through the panel, to consider potential direct and adverse effects on ISH as another mineral rights owner.

Oil and Gas Conservation Act

[26] Approval to drill the 10-01 well was obtained pursuant to the *Oil and Gas Conservation Act* (*OGCA*). Production and operation of the well are governed by the *OGCA* and regulations made in accordance with that act. The purposes of the *OGCA* are set out in section 4 of that act and include

- "to effect the conservation of, and to prevent the waste of, the oil and gas resources of Alberta";
- "to provide for the economic, orderly, efficient and responsible development in the public interest of the oil and gas resources of Alberta"; and
- "to afford each owner the opportunity of obtaining the owner's share of the production of oil or gas from any pool."

Responsible Energy Development Act and the *REDA General Regulation*

[27] *REDA* and section 3 of the *REDA General Regulation* require that when the AER conducts a regulatory appeal in respect of an energy resource activity under an energy resource enactment, it must consider the social and economic effects and the effects on the environment of energy resource activities.

[28] Pursuant to section 1(1)(j) of *REDA*, *OSCA* is an energy resource enactment. Canadian Natural's amendment application was for an energy resource activity. So, while section 3 of the *General Regulation* is relevant to our consideration of the issues on this appeal, the issues and evidence do not cause us to be concerned about potential social or environmental impacts of Canadian Natural's amendment application.

We did consider economic factors as part of our assessment of the parties' submissions on potential consequences of adverse impacts to ISH. That discussion is set out below.

Gas-over-Bitumen Decision and Regional Geological Study

[29] The AER's predecessor, the Alberta Energy and Utilities Board (EUB), conducted an inquiry in the spring of 1997 in response to concerns raised by several companies holding oil sands leases about the potential adverse effects of associated gas production on the eventual recovery of bitumen (GOB Inquiry).

[30] During the inquiry, bitumen producers argued that production of associated gas (accumulations of natural gas found in geological strata directly above and in pressure communication with oil sands deposits) before thermal bitumen production would have detrimental effects on bitumen recovery due to pressure depletion. Gas producers argued that if bitumen were produced before associated gas, some contamination of the gas could result from the generation of hydrogen sulphide (H_2S) and carbon dioxide at elevated bitumen temperatures—a process known as aquathermolysis.

[31] The EUB found that associated gas production would have a detrimental effect on SAGD performance and that in some instances the effect on the ultimate bitumen recovery could be significant.

[32] With respect to the impact of SAGD operations on associated gas production, the EUB stated:

> The Board accepts that the amount of acid gases generated at a thermal bitumen project as a result of aquathermolysis would be a function of that project's operating temperature. The Board further accepts that these acid gases could migrate into overlying gas caps. However, the Board believes that, if necessary, cleaning up the gas should be feasible, albeit at an additional cost. The Board believes that, from a public interest perspective, mitigating this effect would be less costly and more successful than trying to mitigate the effect of associated gas production on thermal bitumen recovery.[1]

[33] In 2003 the EUB initiated a regional geological study of the Athabasca-area Wabiskaw-McMurray deposit (RGS).[2] The RGS was part of the process the EUB undertook to establish bitumen conservation requirements for the Wabiskaw-McMurray deposit in the Athabasca Oil Sands Area. The purpose of the RGS was to identify associated gas pools in the study area. Canadian Natural's Kirby North project lies in the main study area of the RGS.

[34] One conclusion of the RGS was that gas pools are non-associated where the McMurray A2 or B2 mudstones are preserved across the entire region of influence of a gas pool. The RGS also concluded that the Wabiskaw A, C, and D shales, where present, may provide local barriers between gas and bitumen reservoirs. The Wabiskaw A and C shales are not found in the Kirby North area.

[35] EUB decision 2005-122 (the GOB decision) was one decision in the larger GOB process. In this decision the EUB relied on conclusions in the RGS and evidence of the participants in the proceeding and

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[1] Alberta Energy and Utilities Board, *EUB Inquiry: Gas/Bitumen Production in Oil Sands Areas*, March 1998, 49.

[2] Alberta Energy and Utilities Board, Report 2003-A: Athabasca Wabiskaw-McMurray Regional Geological Study, December 31, 2003.

ordered certain gas wells to be shut in. The goal was to maintain adequate pressure in the bitumen reservoirs to ensure efficient production of the bitumen resource. The 10-01 well was among the wells shut in as a result of the GOB decision, and the order relating to the 10-01 well remains in effect. Gas rights holders who want to produce GOB gas must first apply to the AER (the successor regulator to the EUB for energy resource activities) for approval.

[36] Finally, in the GOB decision, the EUB found that the McMurray A2 and McMurray B2 mudstones, where present throughout a region of influence, would separate underlying bitumen from the effects of depleting the overlying gas zone. The EUB also noted that relevant field experience (at that time) was very limited, as was publicly available data regarding the effect of associated gas production on SAGD bitumen recovery.

Case Law and Previous AER (and Predecessor) Decisions

[37] ISH did not ask us to consider specific case law or previous AER decisions in its submissions or final argument. It did rely on the EUB's findings in the GOB decision about the effectiveness of the Wabiskaw C and B as sealing layers. We address this below.

[38] ISH did bring a motion three weeks after the close of the hearing, requesting leave to submit a written legal argument clarifying its position about the law on

- the proceeding being in the nature of a hearing de novo;
- the application of the reasonableness test, if applicable; and
- discharge of the relevant onus.

[39] Canadian Natural opposed ISH's motion. We issued reasons for rejecting the motion on November 12, 2020. A copy of our reasons is attached as appendix 3.

[40] In its final argument, Canadian Natural referred us to a recent AER decision, *2020 ABAER 005*, proposing that we look at the broader context in which this regulatory appeal is being considered. We looked at that decision, and it appears to us that Canadian Natural may have been suggesting that the fact that the KN06 box is a part of Canadian Natural's overall Kirby North development should weigh in favour of affirming the amended approval.

[41] Both ISH and Canadian Natural argued that we should make our decision to confirm, vary, suspend, or revoke the amended approval based on our assessment of the evidence on the record in this hearing. Taking different routes to get there, both ISH and Canadian Natural said we are not reviewing the original decision to grant the amendment application.

[42] Canadian Natural also referenced a line of case law beginning with the Alberta Court of Appeal decision in *Alberta Energy Company Ltd. v. Goodwell Petroleum Corporation Ltd.*, 2003 ABCA 277, 339

AR 201 (*Goodwell*). That case involved the incidental and unavoidable production of gas-cap gas along with underlying bitumen, which is not the issue here. *Goodwell* is therefore not directly applicable to these circumstances.

[43] Canadian Natural ultimately referred us to the reasons given by the AER for granting ISH's request for this regulatory appeal, saying the test we should apply is whether Canadian Natural's plans to develop the KN06 box are reasonable in the circumstances.

[44] The historical context of the GOB decision and RGS assist us in understanding the context of this appeal. However, the findings in the GOB decision focused primarily on which geological formations could prevent pressure-depletion impacts of associated gas production from adversely affecting production of deeper bitumen resources. This is not the issue before us. In addition, there is significantly more information available now in the form of well data (e.g., cores, well logs) and operational experience than there was at the time of the GOB decision. Some of the more recent information was presented in evidence in this proceeding.

[45] No other directly applicable court decision or decision of the AER or its predecessors was brought to our attention in this proceeding, nor are we aware of any. We have considered this regulatory appeal in the context of the legal framework outlined above.

[46] The *AER Rules of Practice* gives the regulator the discretion to allow new information to be submitted in a regulatory appeal if the information is relevant and material to the decision appealed from and was not available to the original decision maker. The record of this proceeding includes a significant amount of new evidence and information that was not before the original AER decision maker. Much of that evidence was about whether ISH's rights to natural gas in the Kirby Upper Mannville II Pool may be directly and adversely affected by Canadian Natural's proposed operations. Additional evidence was presented dealing with the issue of mitigation. To arrive at our decision, we have asked and answered the following overarching questions:

- Do we find that Canadian Natural's proposed operations in the KN06 box, as permitted by the approval, may cause direct and adverse effects to ISH?
- If the answer to the first question is yes, are there reasonable steps that may be taken to avoid and mitigate those effects?

[47] To answer the overarching questions, we identified specific issues for the hearing.

Issues

[48] On the basis of the extensive submissions made in the course of ISH's request for a regulatory appeal, we identified three issues. The parties were given an opportunity to comment, and both agreed with the issues identified by the panel. Over the course of the submission and information-request process

leading up to the hearing, clear subissues were identified associated with the second issue. The third issue also evolved. The issues at the time of the oral portion of the hearing were as follows:

1) The presence/absence of an effective barrier or top seal overlying the bitumen-bearing McMurray Formation, and, if present, its relevant characteristics in the area of the KN06 box
2) The risk of fractures or other breach of the barrier / top seal, if present, resulting from Canadian Natural's operations in the KN06 box
   a) Risk posed by existing faults and/or fractures
   b) Risk of fracturing induced at start-up reaching the Kirby Upper Mannville II Pool
   c) Risk that there is an integrity issue with the 10-01 well that is effectively a breach of any barrier(s) between the McMurray bitumen reservoir and the Kirby Upper Mannville II Pool
3) The need for an observation well(s) in the KN06 box and/or other forms of monitoring and risk mitigation

1) Presence/Absence of an Effective Barrier, and Its Relevant Characteristics

[49] We revised the wording of the first issue to more accurately reflect the evidence on the record of this proceeding. The reworded issue is

> the presence/absence of an effective barrier to steam between the bitumen-bearing McMurray Formation and the gas-bearing Wabiskaw B, and, if present, its relevant characteristics in the area of the KN06 box.

[50] In a request for further information, we asked the parties to provide a table listing what they identified as barrier/sealing intervals and the intervals' physical characteristics, including lithology; average porosity and permeability from core measurements; average gamma ray, neutron, and density porosity values; and presence/absence of fractures.

[51] ISH provided a table listing the Wabiskaw C, the McMurray A2 mudstone, the McMurray B1 mudstone, the McMurray B1 sequence, and the McMurray B2 "nonresistivity." It is not clear whether the last listing is a typographical error or not. ISH did not refer to a McMurray B2 nonresistivity interval anywhere else in its submissions. It did refer to the McMurray B2 regional and the McMurray B2 valley fill in its submissions and included those intervals in particular in its updated stratigraphic chart (see figure 2 below). Nothing in our decision turns on the parties' having listed barrier/sealing intervals in a particular way in their tables. ISH's position was that none of the listed intervals is effective to prevent steam from Canadian Natural's proposed operations in the KN06 box from reaching the Wabiskaw B.

[52] Canadian Natural's table listed the A2 mudstone, upper-B1, mid-B1 mudstone, lower-B1, and post-B2 non-reservoir facies. Canadian Natural did not list the Wabiskaw C in its table because it took the position that the Wabiskaw C is not relevant to this proceeding.

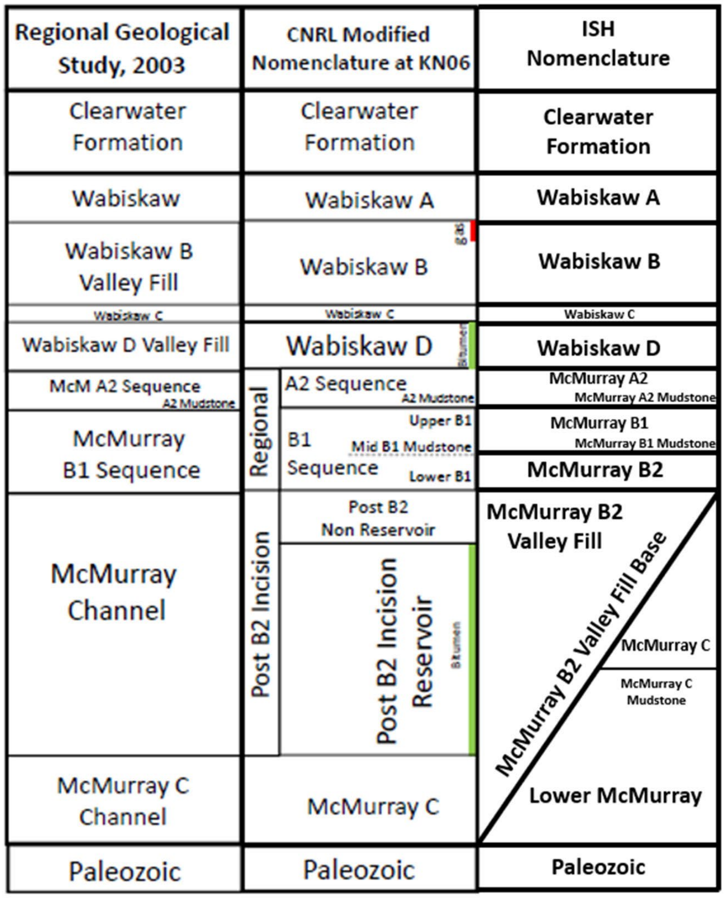

Figure 2. ***Regional Geological Study*, 2003, and the Parties' Respective Stratigraphic Charts.** ISH submitted this exact figure to the AER in ISH's September 25, 2020, *Reply Hearing Submission* (original figure title: "Figure 1: ISH's Revised Strat Chart").

[53] ISH said in its reply submissions that the Wabiskaw C is relevant and is mappable across the entire KN06 box, ranging from 0.7 to 5 m in thickness. ISH asserted that the Wabiskaw C acts as a barrier to pressure transmission between the GOB gas and underlying bitumen, but that bioturbation evident in core samples shows it is not effective to prevent steam reaching the Wabiskaw B from the McMurray. In particular, ISH pointed to the vertical burrows of *Skolithos* as conduits for steam.

[54] In the GOB decision, the EUB found that although the Wabiskaw C may be locally sealing, it cannot be relied on as a regional seal. The EUB also found that for an interval to be considered a local seal, there must be direct evidence that the seal is present throughout the region of influence. Such evidence was lacking for the Kirby Upper Mannville II Pool. In the current proceeding, there was little evidence on the characteristics of the Wabiskaw C. As it was not an issue in the appeal, we make no comment on its effectiveness as a barrier to pressure communication between the Wabiskaw B and underlying bitumen reservoirs.

[55] Canadian Natural's position is that the combined package of sediments comprising the post-B2 non-reservoir inclined heterolithic stratification (IHS); the regional B1 sequence, including the mid-B1

mudstone; and the regional A2 mudstone form an effective barrier to steam between the bitumen-bearing McMurray reservoir and the gas-bearing Wabiskaw B.

[56] In light of the differences between the parties, including differences in stratigraphic nomenclature and interpretation, the subheadings we have used below should not be taken as findings about one party's interpretation over another's. They are intended solely for ease of reference and readability and are based on the stratigraphic charts shown in figure 2 above.

[57] Finally, throughout the parties' evidence and submissions, they referred to intervals or specific lithologic units as baffles or barriers to steam. For the purposes of this decision, we consider a barrier to be a formation or layer that is not permeable to steam over the life of the KN06 box operations. A baffle is an interval that interferes with, inhibits, or impedes the movement of steam but does not prevent it entirely.

The A2 Mudstone

[58] The parties agreed on the identification of the regional McMurray A2 mudstone (A2 mudstone) in the area of the KN06 box. The RGS found that where it is present, the A2 mudstone forms an effective barrier or sealing layer in the context of maintaining pressure separation between a bitumen reservoir and an overlying gas reservoir.

[59] The parties agreed that the A2 mudstone is not present over the northwest corner of the KN06 box. In that area it has been fully eroded. The parties disagreed on the areal extent of where the A2 mudstone is missing.

[60] ISH said that where the A2 mudstone is present and "thick enough," it should act as an effective barrier. ISH disputed that the A2 mudstone is thick enough as it approaches the zero edge in the northwest corner of the KN06 box and nearby area. ISH's interpretation of the A2 mudstone was that it ranges from 0 (zero) m thick to 0.8 m thick within the boundaries of the KN06 box and from 0 (zero) m to 1.0 m thick in the area around the box. ISH interpreted the A2 to be missing in as much as a full legal subdivision, as depicted on its A2 mudstone isopach map. That would equate to approximately 25 per cent of the KN06 box.

[61] ISH also made a point of noting that the A2 mudstone is not a shale. It stated that a shale could be expected to remain competent (i.e., not fracture) through exposure to steam over the life of operations in the KN06 box. At the same time, ISH acknowledged that, where present and of sufficient thickness, the A2 mudstone can be an effective barrier to steam. But it argued that because the A2 mudstone has been truncated in the northwest corner of the KN06 box, it cannot be an effective barrier to steam in this case.

[62] Canadian Natural's interpretation of the A2 mudstone was that it is present over 95 per cent of the KN06 box. Canadian Natural suggested that even though the A2 mudstone has been fully eroded in a

portion of the northwest corner of the KN06 box, the remaining confinement strata are intact and effective as a barrier over that portion of the box. Except for the area where it has been fully eroded, Canadian Natural interprets the A2 mudstone as more than 0.5 m thick over the rest of the KN06 box. The gist of Canadian Natural's argument was that because the barriers it described below the A2 mudstone are intact, it does not matter that the A2 mudstone does not extend across the entire KN06 box; it is the entire package as described earlier that is an effective barrier to prevent steam from reaching the Wabiskaw B.

[63] In exhibit 30.02 at tab 19, Canadian Natural presented gas chromatography–mass spectrometry (GCMS) data[3] for the 1AA/11-01-075-09W4M well located in the KN06 box to support its argument that there are five effective barriers to steam, including the A2 mudstone. According to a paper filed by Canadian Natural[4] (Fustic paper), plotting the biodegradation-susceptible aromatic-hydrocarbon concentrations in samples taken from hydrocarbon-bearing intervals in a given well can show where there is likely to be a barrier between vertically stacked hydrocarbon-bearing layers at that well location. Hydrocarbons isolated within the same geologic compartment will have similar concentration values. Where the data exhibit more or less continuous hydrocarbon chemistry from one reservoir or interval to the next, connectivity exists between those units. Canadian Natural said, "Barriers are demarcated by clear, sharp concentration changes at a specific depth."

[64] The GCMS data from samples taken from the KN06 1AA/11-01-075-09W4M well, which Canadian Natural identified as the type well for the KN06 box, include one sample a distance of less than 1 m above the top of the A2 mudstone and three samples in the upper-B1 sequence. There is an offset of about −50 µg/g of oil between the samples immediately above and below the A2 mudstone.

[65] ISH did not dispute the usefulness of GCMS data or the fact it can be used to identify separate geologic compartments. ISH did challenge the way Canadian Natural interpreted the GCMS data in this case, saying Canadian Natural relied on an outdated model.

Panel's Analysis and Findings

[66] We find that on the basis of the information provided in the Fustic paper, there will be a noticeable lateral offset in aromatic-hydrocarbon concentrations between different geologic compartments. The more abrupt and marked the offset, the greater the probability that the compartments are separated by a barrier and not a baffle. Here the GCMS data from the type well support the argument that the A2 mudstone acts to separate the upper-B1 and McMurray A2 reservoirs, where it is present.

[3] GCMS data is obtained through gas chromatography–mass spectrometry analyses of bitumen extracted from cores. Anaerobic biodegradation of hydrocarbons occurs within the oil-water transition zone. In that zone, diffusion of biodegradable hydrocarbon components through the oil column to the active biodegradation zone is responsible for observed vertical compositional gradients when GCMS data are plotted. (Fustic M., Bennett, B., Adams, J., Huang, H., MacFarlane, B., Leckie, D., and Larter, S., "Bitumen and Heavy Oil Geochemistry: A Tool for Distinguishing Barriers from Baffles in Oil Sands Reservoirs," *Bulletin of Canadian Petroleum Geology* 59, no 4. (2011): 295–316.)

[4] Fustic et al, "Bitumen and Heavy Oil Geochemistry."

[67] However, because the A2 mudstone has been eroded and is therefore absent over at least a portion of the northwest corner of the KN06 box, we find that the A2 mudstone on its own cannot be considered an effective barrier to steam between the bitumen-bearing McMurray Formation and the gas-bearing Wabiskaw B over the whole KN06 box. The extent of the complete erosion of the A2 mudstone in the northwest corner of the KN06 box does not affect our decision.

The B1 Intervals other than the Mid-B1 Mudstone

[68] The parties agreed that the B1 sequence comprises two intervals separated by the B1 mudstone. Canadian Natural referred to separate upper- and lower-B1 units. ISH referred to the B1 and regional B2 sequences.

[69] The parties also agreed that the B1 sequence consists of mudstones and/or siltstones interbedded with sandstones (or a heterolithic sequence). They agreed that within the interbedded packages, both fining- and coarsening-upward sequences exist. They also agreed, and it is clear from the core evidence on the record, that the sand beds are bitumen saturated. ISH's position was that this is important because bitumen-saturated sands and coarser-grained sequences are more likely to be or to become potential pathways for steam.

[70] Finally, the parties agreed that what Canadian Natural identified as the lower-B1 unit and ISH called the regional B2 consists of sandstone- to mudstone-prone tidal-flat deposits.

[71] Because both parties identified the mid-B1 mudstone as a potential barrier independent of the remainder of the B1 sequence, we will address it separately below.

[72] ISH interpreted what it called the McMurray B1 sequence as being successions of sandstones and mudstones that are highly variable, small in scale, stacked, and coarsening or fining upward. ISH said the sands are bitumen saturated. It submitted that there is a sand-dominated trend in the southwest corner of the KN06 box and that the sand-dominated facies would act as spill points for steam.

[73] ISH interpreted what it identified as the McMurray B2 regional as thin, ranging from 1.0 to 3.0 m in thickness over the KN06 box. ISH described a tidal-flat assemblage that grades laterally from dominantly bitumen-saturated sandstone to dominantly mudstone. ISH further interpreted this assemblage as a set of shallow progradational sequences that are not laterally extensive. ISH acknowledged that fine-grained facies can impede steam. But it argued that the assemblage as a whole cannot be considered a barrier to steam because, like the McMurray B1 sequence, it is dominated by sandstones, so there will be spill points.

[74] Finally, ISH submitted that what it called the McMurray B1 and the McMurray B2 regional cannot be barriers to steam because they are dominated by sands over the KN06 box.

[75] Canadian Natural interpreted the entire B1 sequence, including the B1 mudstone, to range from 7.1 to 9.7 m in thickness over the KN06 box. It noted that within the upper- and lower-B1 sequences, the individual units, each representing a depositional cycle, “may appear quite variable.”

[76] Canadian Natural did not rely on direct evidence to say the B1 sequence over the KN06 box is an effective barrier to steam. Rather, it referred to a 2011 paper by Collins et al.[5] and said that “facies that are similar to the B1 are effective as confinement strata due to the combination of low vertical permeability and high capillary entrance pressures.”

Panel’s Analysis and Findings

[77] The Collins et al. study relied on by Canadian Natural looked at the operating performance of several mature SAGD projects to assess and model the effectiveness of geological facies that grade upward to poorer reservoir quality as barriers to or containment for steam. The Kirby South and existing Kirby North projects were not included in the Collins et al. study. There is insufficient evidence before us to conclude that the lithologies, stratigraphy, and depositional environments of the projects assessed and modelled by Collins et al. are sufficiently analogous to what is found in the KN06 box. We therefore do not base any conclusions on that study.

[78] Based on the evidence in this proceeding, we are not able to conclude that the upper and lower B1, as interpreted by Canadian Natural, or the upper B1 and regional B2, as interpreted by ISH, form a completely effective barrier to steam on their own. To the extent that the sandstone intervals in the interbedded sequences provide potential pathways for steam, the upper and lower B1 may act as baffles, slowing the progress of any steam moving through those intervals from the McMurray.

The Mid-B1 Mudstone

[79] Initially, both parties agreed that the mid-B1 mudstone was present over the entire area of the KN06 box. They also agreed that the mid-B1 mudstone is similar geologically to the A2 mudstone. In particular, both interpreted the mudstone to be associated with a marine flooding surface between parasequences.

[80] ISH interpreted the mid-B1 mudstone to be a thin, silty, highly bioturbated mudstone. ISH’s interpretation of the extent of the mid-B1 mudstone changed over the course of the process leading up to the hearing. Specifically, after ISH obtained access to logs and core data it had not examined previously from wells in the KN06 box, ISH’s geologist, Mr. Mathison, said the mid-B1 mudstone is not present in at least two wells in the KN06 box. His revised map of the mid-B1 mudstone shows the mid-B1 mudstone ranging from 0 m to 0.7 m thick in the KN06 box.

[5] Collins, P. M., Walters, D. A., Perkins, T., Kuhach, J. D., and Veith, E., “Effective Caprock Determination for SAGD Projects” (CSUG/SPE 149226-PP paper presented at the Canadian Unconventional Resources Conference, Calgary, Alberta, November 15–17, 2011).

[81] ISH also indicated that where it thins, the mid-B1 mudstone cannot be expected to remain competent and act as a barrier to steam over time.

[82] Canadian Natural said that the mudstone portion of the B1 sequence represents "variable stratigraphy." It disagreed with ISH's updated interpretation of the extent of the mid-B1 mudstone. Canadian Natural said that ISH was not accurately identifying the mid-B1 mudstone and therefore not accurately mapping it. By way of example, Canadian Natural pointed to core from the 1AA/06-01 well in the KN06 box and showed that there is clearly a mudstone present within the overall B1 sequence of sediments. Canadian Natural interpreted it to be the mid-B1 mudstone. Mr. Mathison, for ISH, found the mid-B1 mudstone to be absent from this well.

[83] Canadian Natural suggested that we may infer that because the A2 and mid-B1 mudstones are similar in lithology and because the RGS found the A2 mudstone to be an effective barrier to pressure where it is present over an area of concern, the mid-B1 mudstone may also be found to be an effective barrier where it is present.

[84] Finally, Canadian Natural's GCMS data show an abrupt offset of approximately 240 µg/g of oil between samples taken in the type well about 1 m above and below the mid-B1 mudstone, which they said indicates a barrier between compartments.

Panel's Analysis and Findings

[85] Referring to both the digital core photos and the well logs, it is possible to identify the mid-B1 mudstone in the wells where ISH argued it is missing. In addition, as the mid-B1 mudstone is associated with a marine flooding surface, we find it is more likely than not that while the mid-B1 mudstone may vary laterally in terms of its sedimentological attributes and thickness, it probably extends across the KN06 box.

[86] The core photos in evidence, specifically those from wells within the KN06 box, show that the mid-B1 mudstone appears within a package of interbedded, generally bioturbated mudstones and sandstones. The package includes mudstones with minor sandstones and sandstones with abundant mudstone interbeds. The extent and type of bioturbation in the mid-B1 mudstone in the core samples are not comparable to that of the A2 mudstone. Locally, a moderate to high degree of bioturbation is evident in the A2. The mid-B1 mudstone does not appear, from the core photos provided, to have a similarly high degree of bioturbation. In addition, the diversity and abundance of trace fossils are noticeably different between the A2 mudstone and the mid-B1 mudstone.

[87] Petrophysical data provided by the parties show similarities in the B1 and A2 mudstones. But, while we agree that the A2 and mid-B1 mudstones have similar lithology, we cannot say that their depositional environments were the same. As a result, we cannot conclude that, based solely on lithologic similarities between the two, the mid-B1 mudstone would be an effective barrier to steam.

[88] However, the GCMS data across the mid-B1 mudstone show the clearest evidence in that data set of a barrier. On that basis and in light of our finding that it likely extends across the KN06 box, we find that the mid-B1 mudstone is more likely than not an effective barrier to steam.

The Post-B2 Non-reservoir Units

[89] The parties agreed that the post-B2 non-reservoir interval consists of IHS point-bar deposits. The parties also agreed that the IHS units consist of mudstones and siltstones interbedded with sandstones.

[90] In their interpretations of the various core samples they reviewed, the parties disagreed on the exact placement of the base of the B2 non-reservoir IHS. They also disagreed about whether it can or will prevent steam moving from the McMurray reservoir to the Wabiskaw B.

[91] ISH interpreted the post-B2 non-reservoir IHS depositional environment to be tidal. It did not address the post-B2 non-reservoir facies in its original submissions. Relying on the GOB decision and the RGS, ISH categorized the facies as reservoir and so not effective barriers to steam.

[92] Canadian Natural interpreted the post-B2 non-reservoir IHS deposits to be part of a meandering fluvial point-bar system. It said that “mudstone prone” IHS caps the B2 reservoir units in the KN06 box. Canadian Natural interpreted the individual IHS as being on the order of 10 cm to a metre in scale, composed of variably bioturbated silty mudstones with centimetre-to-decimetre-scale sandstone interbeds. It said the sandstone interbeds decrease in number and scale vertically.

[93] Canadian Natural interpreted the top of the reservoir in the KN06 box to be the point where the permeability is too low to allow steam to penetrate overlying facies. In Canadian Natural’s interpretation, the permeability decreases with increasing mudstone content. Canadian Natural described a “wedge-shaped, mudstone prone deposit ranging in thickness from 1.4 to 6.4 meters” over the KN06 box. It acknowledged there are variations in the sand content of the IHS units that cap the valley fill but added that it had identified on 3D seismic the abandonment plug of the upper tier of those units. The plug, Canadian Natural said, is to the north of the KN06 box. Canadian Natural went on to say it had mapped a continuous muddy-to-mixed IHS facies across the entire post-B2 reservoir unit and concluded that the upper tier appears to be sealed.

[94] Referring to its GCMS data in the type well, Canadian Natural identified three “clear barriers” in the post-B2 non-reservoir interval between its interpreted SAGD top and the post-B2 incision top.[6]

[95] Finally, Canadian Natural relied on its operational experience to say it knows that whatever the specific geometry and relative orientation of the IHS units may be, they are effective at preventing vertical steam-chamber growth. In addition, Canadian Natural submitted Schlumberger reservoir saturation tool logs (RST logs) from its Jackfish project. The RST logs are used to assess gas saturation

[6] Exhibit 30.02, tab 19.

over time and may be used to compare that with steam-chamber development. Canadian Natural said RST log interpretations of steam-chamber growth have been validated with a variety of means, including lateral temperature and pressure data, observation-well temperature and pressure data, and 4D seismic. Canadian Natural submitted that the RST logs from the Jackfish project show that after ten years of SAGD operations, the steam chamber remains confined below the post-B2 non-reservoir facies. Canadian Natural went on to say that the confinement strata present in the example from Jackfish are the same as those in the area of the KN06 box.

[96] ISH responded to Canadian Natural's interpretation of the post-B2 non-reservoir interval, saying that what Canadian Natural described as shales in the post-B2 non-reservoir facies are mudstones. ISH said they cannot act as barriers to steam because they are discontinuous and change laterally from mudstone to sandstone. ISH said that IHS in the KN06 box are not laterally extensive. It relied on the example of what it described as a typical unit with an angle of inclination of 8°, which would only be 24 m wide based on a straightforward trigonometric calculation. ISH's geologist said he got the estimate of 8° from the Fustic paper.

[97] As for the post-B2 non-reservoir sequence, ISH said that since the mudstones that occur in IHS units are part of a sequence containing bitumen-bearing sands, the architecture of the whole package of IHS in the KN06 box is such that there will be pathways through the sands winding up and through the interval. ISH described the presence of "tortuous" pathways for steam. It said that "at best," valley fill shales should be considered as baffles and not competent barriers to vertical steam propagation.

[98] Lastly, ISH argued that Canadian Natural was misinterpreting the GCMS data. ISH said Canadian Natural relied on an outdated model to interpret the GCMS data in the McMurray. ISH said Canadian Natural applied an earlier model described by J. J. Adams[7] and not the more recent model described in Fustic et al. ISH noted that Adams was part of the team that contributed to the more recent model. Using the Fustic model, ISH said the GCMS data points show a downward decreasing concentration gradient from the base of the B1 mudstone and that the proper conclusion to draw is that these may be baffles, not barriers.

Panel's Analysis and Findings

[99] Neither party provided sufficient evidence to develop a model of the IHS sequence in the KN06 box.

[100] IHS is spatially complex. The lateral continuity of baffles and barriers in the IHS is also difficult to predict on the basis of the available core data because individual IHS units may be less extensive laterally than existing core spacing. In its original application, Canadian Natural identified uncertainty about both lateral and vertical permeability in the Kirby North reservoir due to geological heterogeneities

[7] Adams, J. J., "The Impact of Geological and Microbiological Processes on Oil Composition and Fluid Property Variations in Heavy Oil and Bitumen Reservoirs" (unpublished PhD thesis, University of Calgary, 2008), 746.

in IHS units. It should be noted that it also said, in answer to a question in the hearing, that while developing the Kirby North project, Canadian Natural benefited from geostatistical modelling from Kirby South to better understand operational issues that would arise due to that uncertainty. Canadian Natural said that because of that modelling, it modified its Kirby North drainage boxes to account for the presence of thicker, less permeable facies higher in the McMurray that would inhibit vertical steam-chamber growth.

[101] Canadian Natural provided no geostatistical modelling in this proceeding. Geostatistical models could provide a range of estimates for how long the strata identified as confining strata would confine steam to the McMurray.

[102] We give limited weight to the RST logs because we do not have the evidence before us to say that the Jackfish stratigraphy and lithology are sufficiently analogous to those in the KN06 box. However, the RST logs provide some support for the concept that steam chambers may be contained by degrading quality in reservoir facies and by fining-upward heterolithic sequences.

[103] We find that the specific depositional environment for IHS in this case is less important than the actual distribution of sandstones and mudstones within individual IHS units and the spatial relationship of those individual IHS units to adjacent units (whether over, under, or beside).

[104] Finally, we find the GCMS data from the type well to be helpful for assessing the potential effectiveness of the post-B2 non-reservoir facies as a barrier to steam. We cannot conclude that there are three “clear barriers” within the McMurray reservoir. We do find that the GCMS data show one barrier at the interface between the McMurray B2 reservoir and the post-B2 non-reservoir IHS. There is a sharp offset at that interface of approximately 70 µg/g of oil. Within the post-B2 non-reservoir interval in the GCMS data, the data pattern more closely matches what would be interpreted as baffles. As a result, we find that based on Canadian Natural’s operational experience to date and the GCMS data, there is more likely than not a barrier between the McMurray B2 reservoir and the post-B2 non-reservoir interval. We also find that the post-B2 non-reservoir interval can be expected to act as a baffle to steam movement, but not a barrier.

The Combined Package of the Post-B2 Non-reservoir Interval, the B1 Sequence, and the A2 Mudstone

[105] In summary, we find that the A2 mudstone, where present, is an effective barrier to steam. However, it is not present across the entire KN06 box, so it alone cannot be considered an effective barrier. The mid-B1 mudstone is more likely than not an effective barrier across the entire KN06 box. The IHS sequence is spatially complex and is likely not a barrier to steam but would act as a baffle. And there is likely a barrier in the facies moving from the McMurray B2 reservoir to the post-B2 non-reservoir (IHS) unit.

[106] As a result, we conclude that it is more likely than not that the combined package of the post-B2 non-reservoir interval, the entire B1 sequence (including the mid-B1 mudstone), and the A2 mudstone, where present, should effectively confine the movement of steam to geologic strata below the Wabiskaw B in the KN06 box.

2) The Risk of Fractures or Other Breach of the Barrier / Top Seal, If It Is Present, Resulting from Canadian Natural's Operations in the KN06 Box

[107] ISH identified three subissues:

a) Existing faulting and fracturing can provide pathways for steam to the GOB reservoir.

b) Fractures could be induced at Canadian Natural's proposed maximum 7 MPa operating pressure (MOP) at start-up.

c) The 10-01 well appears to be compromised, creating a pathway for steam to the GOB reservoir.

a) Risk Posed by Existing Faulting and Fracturing

[108] ISH initially said there was evidence of large-scale faulting in the KN06 box. ISH had built a geologic cross-section across the KN06 box, interpreting a fault with a displacement of approximately 7.5 m. ISH had also referred to the potential for salt-edge-collapse faulting in the area of the KN06 box. After accessing additional information through the information-request process, ISH said it could agree with Canadian Natural that there is no evidence of large-scale faulting (i.e., with a displacement greater than 7.5 m) in the KN06 box and no evidence of salt collapse. However, at the oral hearing, ISH appeared to revert to its position that there is a fault or other structure of about 6.6 m vertical displacement at the Paleozoic, as demonstrated by what ISH said is a vertical offset in the oil-water contact.

[109] There was significant disagreement between the parties about the presence of small-scale fractures or fracture systems in the KN06 box that could breach containment layers. ISH did not provide its own independent evidence on this point. Instead, it did its own analysis of evidence provided by Canadian Natural—specifically, digital core photos, 3D seismic, and well logs—to support this point.

[110] In ISH's direct evidence at the hearing, Mr. Mathison, on behalf of ISH, took us through a series of digital core photos, pointing out and describing examples of what he interpreted to be fractures and why. In the examples below, all references are to the PDF page number in ISH's prefiled opening statement.[8]

a) PDF page 8, paragraph 38: "If you look at the bottom column on the left hand side, there is a significant vertical fracture. In addition, since you cannot match the sedimentary layers across this fracture, it indicates that there has been vertical displacement, indicating that this is indeed a fault."

[8] Exhibit 86.02, pages 8–17.

b) PDF page 10, paragraph 43: "If we go to the third column from the bottom, you will see on the right hand side that this column has a vertical fracture, and that the overlying silty mudstones have highly variable inclinations, suggesting that it has been completely fractured after lithification."

c) PDF page 10, paragraph 46: ". . . moving to the centre of the second column from the top, just to the right of the red line below it, there is a sand-filled fracture, which indicates that the timing of fracturing occurred after oil migration and degradation into bitumen."

d) PDF page 11, paragraph 47: "Finally, moving to the top of the McMurray, and the base of Wabiskaw D, if you look to the bottom column on the right hand side, we see highly deformed strata that has also been cut by small scale fractures."

e) PDF page 17, paragraph 58: "Looking again to the lowest column, below the B1 mudstone to the bottom of the core to the right, you will note that there is a vertical fracture network coming through the core. You will also notice that some of the fractures are sand-filled, and are small vertical lines that disrupt the stratigraphy in the core."

[111] On cross-examination Mr. Mathison accepted that there could be alternate interpretations for some of the core he had reviewed. However, he reiterated ISH's position that there was clear evidence of fracturing in the core in evidence.

[112] With respect to Canadian Natural's 3D seismic evidence, ISH argued that Canadian Natural should have shown or should be required to show that there is no evidence of small-scale fracturing or faulting in or near the KN06 box in Canadian Natural's full seismic data set. ISH said Canadian Natural could supplement its interpretation of the 3D seismic data it did provide by using attribute analysis to detect and assess any lateral discontinuities—specifically, fractures or small-scale faults that would not otherwise be resolvable.

[113] Mr. Vermeulen, ISH's geophysicist, said in questioning that he could not see evidence in the seismic of a fault with a 7.5 m offset that intersects the location where ISH relied on a geologic cross-section it constructed to interpret a fault with an offset of that magnitude. He suggested and ISH argued that Canadian Natural should have to conduct further seismic analysis to better assess whether the seismic data show evidence of small-scale faulting and fracturing. He referred to attribute analysis, specifically mentioning pre-stack seismic analysis.

[114] ISH also submitted that a series of seismic semblance slices above and below the Wabiskaw B horizon would show whether weak curvilinear features seen in the seismic semblance slices provided by Canadian Natural are faults or not. ISH asked Canadian Natural in questioning what additional analysis it had done on the seismic data, if any. Canadian Natural confirmed that it had looked at other attributes in the area, specifically mentioning spectral decomposition and curvature attributes. However, it said that attributes it had analyzed were more useful for understanding the bitumen reservoir quality and that the curvature attributes showed differential compaction, not faulting.

[115] In final argument ISH asked us to infer that either Canadian Natural did do the additional analysis and the analysis does not support Canadian Natural's position, or Canadian Natural did not do the analysis at all. ISH implied that not doing further analysis would be falling short of industry standards and what Canadian Natural ought to be required to do.

[116] Finally, in its direct evidence at the oral portion of the hearing, ISH referred to cross-section W-W′ in exhibit 29.01. It said that included in that cross-section is an offset of the oil-water contact of about 7.5 m between the 1AA/06-01 well and the 1AC/07-01 well. ISH said that oil-water contact offset would be explained by a fault initiated in the Paleozoic and extending through the Mannville Group, constituting a breach of the containment layers. Mr. Mathison, on behalf of ISH, identified the oil-water contact as the point of a "dramatic increase in the resistivity" within metres of the top of the Paleozoic in each well.

[117] In its reply evidence, ISH also referred to an apparent offset of over 6.5 m in the oil-water contact in cross-section K-K′ as further support for evidence of faulting, fracturing, or some other form of structural deformation having taken place after deposition of the McMurray sediments and migration of oil into the reservoir facies in that formation. ISH pointed out that the K-K′ cross-section is stratigraphic (using a datum that would show the sedimentary layers and their spatial relationship to each other as they were at the geological age of the datum) and the W-W′ cross-section is structural (using a datum intended to show the geology as it appeared at the geological age of the chosen datum). Finally, ISH suggested that its interpretation was further supported by Canadian Natural's evidence that the original oil-water contact would "freeze" in place and be subject to being flexed or bent due to later, deeper structural changes.

[118] ISH also responded to Canadian Natural's assertion that what ISH was interpreting as faulting or large-scale structural flexures in the KN06 box is in fact evidence of differential compaction of sands and mudstones/shales in the post-reservoir McMurray interbedded sandstones and mudstones. ISH said that in light of the very thin interbedded mudstones/shales (which it said compact more) and higher proportion of sands (which it said compact less) in the McMurray, differential compaction would not explain an offset of 6.6 to 7.5 m.

[119] Canadian Natural took us through the core photos referred to by ISH. Canadian Natural challenged most of ISH's interpretation of fractures in the core in evidence. Canadian Natural agreed that there is a vertical fracture in the Paleozoic interval, which was the first example of a fracture given by ISH. About that fracture Canadian Natural said that if faulting in the Paleozoic predates deposition of the McMurray, any fractures in the Paleozoic (which is deeper than the McMurray Formation) would not impact the containment capacity of the layers above the McMurray B reservoir.

[120] Canadian Natural also said that drilling can cause fracturing in core and that drilling-induced fractures have a telltale petal pattern. Canadian Natural's geologist, J. Lavigne, pointed to an example of what Mr. Mathison identified as existing fractures as an example of petal-pattern fractures resulting from drilling.

[121] Canadian Natural said the rest of the features described by ISH as fractures or evidence of fracturing were all more appropriately interpreted as either biogenic features, such as trace fossils created by burrowing organisms, or due to natural physical processes such as desiccation (drying out of a mud layer), slumping, or brecciation. Canadian Natural said that fractures are planar and many of the features interpreted as fractures by Mr. Mathison appear curved or rounded.

[122] During questioning, counsel for ISH took Mr. Lavigne through examples of core that ISH interpreted as evidence of fracturing. In each case, Mr. Lavigne did not agree, describing what he observed as being the results of either biogenic or sedimentological processes (e.g., slumping). Mr. Lavigne was confident there was no evidence of fracturing in the core; he said fractures "completely do not exist in the reservoir," when asked about the apparent disruption of sediments in a siderite-cemented interval viewed in the core.

[123] Canadian Natural also relied on microresistivity image logs (image logs) to support its position on this issue. Image logs allow interpreters to evaluate the immediate vicinity of a wellbore for faulting and fracturing with displacements below the resolution of what can be seen on seismic. Canadian Natural submitted and evaluated image logs from 20 wells in and around the KN06 box. It said the analysis covered the interval of a few metres below the top of the Paleozoic to the top of the Wabiskaw. Canadian Natural determined that the fracture intensity was very low. It said the highest density of fractures observed were within the top few metres of the Paleozoic interval. Canadian Natural did identify two faults/fractures outside of the zone of interest but said no fractures or faults were identified in the confinement strata from the 20 image logs.

[124] ISH did not provide its own analysis of the image logs and did not challenge Canadian Natural's image-log interpretation. However, ISH did note that when it asked for microresistivity image logs through its information requests, Canadian Natural responded with image logs in PDF format at a 1:20 scale. ISH said the format and scale are not appropriate for correlating what is seen as vertical fracturing in core to the corresponding image logs. In addition, ISH said that fractures oriented closer to the vertical are more likely to be missed in core, referring to the "Terzaghi effect."

[125] Canadian Natural asserted that its seismic data is of high quality and that the parameters used to acquire and process the data in evidence in this proceeding are such that faults with a displacement of 7 m or even less would be resolvable at the relevant depths. It also acknowledged that faults with displacement of 2 to 3 m would not be seen on the seismic.

[126] About the seismic semblance slice referred to above, Canadian Natural said because its seismic sections do not show offset at the relevant horizons in the location of the lineations on the semblance slice, it did not interpret those lineations as faulting in the containment zone. Canadian Natural provided a second semblance slice as part of its responses to ISH information requests, this one also described by

Canadian Natural as covering the same subsurface plane. However, it was a depth slice. The original semblance slice Canadian Natural submitted was a time slice.

[127] On the topic of the faults through the KN06 box interpreted by ISH on the basis of geologic cross-sections, Canadian Natural said there is no corresponding evidence of those faults in the seismic data. It argued that ISH's interpretation of fault offset resulted from a stratigraphic interpretation based on an outdated understanding of the geology. With respect to ISH's interpretation of the oil-water contact, Canadian Natural said the oil-water contact would initially be horizontal and would quickly (presumably in geologic time) "freeze" in place as the bitumen degraded. That horizontal contact would then be distorted by any later structural movement originating from below. Canadian Natural also said that since the two wells referred to by ISH are 241 m apart, the degree of incline in the oil-water contact between the two wells can be calculated to be about 1.8°, reflecting a very subtle structural change unlikely to result in fracturing of overlying formations.

[128] Finally, Canadian Natural pointed to its operational experience as further evidence that there are no existing vertical faults, fractures, or small-scale fracture systems connecting the McMurray D bitumen reservoir to the Wabiskaw B gas reservoir. Canadian Natural said it observed no loss of circulation during drilling of any of the stratigraphic wells in the KN06 box. If there was significant fault- or fracture-supported communication, Canadian Natural would have expected it to show up as a loss of circulation. Canadian Natural continued to observe that

> a differential pressure of greater than 1.7 MPa has been maintained between the McMurray Formation and the Kirby Upper Manville II gas pool (refer to Paragraph 34 above). If open natural fracture and/or faults conduits existed at KN06, then the McMurray Formation bottom water would feed into the gas pool and increase the pressure. This has not been observed and as such, it is concluded that any potential natural fractures are effectively closed under current conditions.[9]

Panel's Analysis and Findings

[129] The digital core photos come from vertical wellbores, so there could be vertical or near-vertical fracturing not intersected by the wells from which the cores were taken. However, the lack of vertical fracturing in the digital core photos in evidence persuades us that there is likely no significant small-scale fracturing in the relevant geological layers that poses a real risk to the integrity of the individually identified potential barriers or to the package of layers we have identified as effective for containing the movement of steam.

[130] Our finding is based on the core photos, particularly those reviewed during ISH's direct evidence. Except for the first instance—the fracture in the Paleozoic—the remainder of Mr. Mathison's interpretations of fractures and small-scale faults are not consistent with what can be seen in the core. The following examples refer to the same core photos as above, where we set out ISH's evidence on this point:

[9] Exhibit 30.02, page 29, paragraph 131.

a) Canadian Natural agreed that this could be a fault. However, given the significant age difference between the Paleozoic and the overlying McMurray, if this is a fault, it may predate McMurray deposition.

b) This feature is more consistent with root traces, as they are infilled with organic matter and located within a mudstone that appears to have undergone pedogenesis.

c) This example is most consistent with the morphology of a *Skolithos* burrow.

d) This example is consistent with the morphology of a small-scale syn- to post-depositional slump feature in a deltaic or shoreface setting and is likely not a fracture.

e) The resolution of the core photos makes it difficult to identify these features confidently. However, the position of the features in the stratigraphic section and the morphology suggest that they are most likely vertical continental burrows.

[131] The image logs coming from vertical wellbores suffer the same limitation as the digital core photos; that is, they are less likely to intersect vertical fractures. The image logs also suffer from the limitations relating to scale pointed out by ISH. While we do find that the image logs in evidence do not show any obvious signs of significant fracturing or faulting, they provide some support for Canadian Natural's position but are not conclusive.

[132] Turning to the seismic, we find Canadian Natural's seismic data appropriate for assessing structure at the Paleozoic level. While there appears to be structure at the Paleozoic that carries up through the geologic section, it does not have the seismic character we would expect to see at a fault with vertical displacement of the magnitude interpreted by ISH. More specifically, given the acquisition and processing parameters, we would expect to see an offset, break, or other interruption or visible change in the seismic peaks/troughs moving laterally from one side of a fault with a 7 to 7.5 m offset at the Paleozoic and at the Wabiskaw B. No such change is apparent in this seismic.

[133] ISH contended that Canadian Natural should have done more analysis of its seismic or provided more seismic data.

[134] In its information requests to Canadian Natural, ISH asked for seismic data sets encompassing the extent of specific geologic cross-sections already in evidence. ISH said the data should include "a Pre Stack Time Migration (preferably unfiltered) and Semblance." ISH also requested horizon interpretations/picks, including a detailed list of horizons. Canadian Natural did not provide all requested information. Instead, it provided reprocessed versions of seismic and a semblance map at approximately the same horizon as it had previously provided, but using a different vertical scale and from a seismic data set that had been processed differently.

[135] To answer ISH's assertion that we should draw an adverse inference because Canadian Natural did not provide all requested seismic data and did not either do or provide attribute analysis or additional

semblance slices, Canadian Natural said it chose to provide the seismic data that would show the faulting that ISH interpreted to be in the KN06 box, if it were present. Canadian Natural said its proprietary seismic data is commercially sensitive, so it was selective about what to share.

[136] We find that the seismic that Canadian Natural did provide was oriented such that if the faults that ISH interpreted from its structural cross-sections were present in the KN06 box, they would have been evident.

[137] We also find that the two semblance slices provided by Canadian Natural are not conclusive. The first is a time slice, the second a depth slice. The depth slice clearly shows artifacts of the surface footprint of the seismic acquisition survey. Both slices show roughly northeast-to-southwest-trending curvilinear features. However, without directly comparable slices above and below the slice provided, we cannot conclude whether the anomalies are structure related or due to non-structural changes.

[138] Overall, the seismic evidence on the record confirms what the parties have already agreed on—the absence of large-scale faulting. We are not able to conclude on the basis of the seismic evidence that there are or are not small-scale faults or fractures.

[139] In summary, based on the digital core photos on the record, we are not persuaded that there are existing small-scale faults or fractures that pose a meaningful risk. Similarly, there is not enough evidence in the core photos, image logs, or seismic data to establish the existence and potential distribution of any faults, fracture systems, or networks. This finding is further supported by Canadian Natural's evidence that it did not observe any loss of circulation when drilling the KN06 box stratigraphic wells. However, the recently recorded pressures in the Kirby Upper Mannville II Pool at the 10-01 well demonstrate that there may be a new or previously undetected issue or issues that could include undetected fracture or small-scale fault-related communication with the Kirby Upper Mannville II Pool. The recently recorded pressure and other anomalies at the 10-01 well are addressed further below.

b) Risk of Inducing Fracturing at Start-Up with an MOP of 7 MPa

[140] ISH took the position that a maximum operating pressure (MOP) of 7 MPa at start-up creates a risk of induced fracturing of containment layers between the McMurray and the Wabiskaw B.

[141] Canadian Natural said it does not expect to have to operate at 7 MPa to initiate circulation of the injection wells at the KN06 box; however, it requested an approval of an MOP of 7 MPa at start-up to have the operational flexibility to do so if necessary. Canadian Natural's evidence was that this flexibility is important because of potential operational impacts that can arise if circulation is not initiated at 6 MPa—specifically, pressure kicks from slugs of fluid moving from the well being started up to the central processing facility. Fluid slugs can form when the MOP used at start-up is not high enough, when combined with other start-up practices (e.g., gas injection), to initiate circulation.

[142] ISH did not provide any independent evidence of the risk of start-up-induced fractures. ISH stated that at the KN06 box, the barrier separating McMurray bitumen from GOB reserves is the McMurray shales or mudstone. ISH said that because the thickness and stress gradient of the McMurray shale or mudstone varies across the KN06 box, a safety factor should be applied to the maximum stress gradient obtained from the test data. ISH advocates for an 80-per-cent safety factor because that is the factor applied by the AER to establish MOPs using stress gradients measured in the Clearwater caprock in the area including the Kirby North development.

[143] ISH was particularly concerned that induced fracturing at Canadian Natural's planned KN06 well pair identified as 12-1 could adversely affect the 10-01 well. That SAGD well pair is close to the 10-01 well. Canadian Natural said the planned well trajectory would bring it within 18.74 m of the 10-01 well.

[144] Finally, ISH referred to the flow-to-surface events at Canadian Natural's Primrose project. ISH did not directly link those events and Canadian Natural's proposed KN06 operations. ISH appropriately noted the Primrose operation was different (high-pressure cyclic steam stimulation) from the KN06 operation. We find the Primrose incident is not relevant to this proceeding and will not deal with it further in these reasons.

[145] Canadian Natural provided evidence in support of its position on this issue in the form of

- analysis of Kirby North field data,
- in situ stress analysis,
- GeoSim (geomechanical) modelling, and
- a risk assessment.

[146] The field data analysis, in situ stress analysis, and risk assessment were covered in a report prepared by T. Boone.[10] Dr. Boone was retained by Canadian Natural to provide an independent report. His opinion was "limited to assessing the risk of fractures that are generated during the start-up of steam circulation, breaching barriers or top seals that may prevent or impair the flow of fluid from Canadian Natural's SAGD operations in the McMurray formation upwards into shallower Wabiskaw gas bearing formations."

[147] Dr. Boone noted in the scope and limits section of his report that the barriers he considered are in the McMurray and Wabiskaw Formations, not the Clearwater caprock, which is not relevant to this proceeding. He also made the point that although risks associated with fluid migration from the McMurray into the Wabiskaw are not safety or environmental risks, Canadian Natural "is required to responsibly develop the resources in the McMurray in a manner that minimizes any potentially negative impacts on future development of the Wabiskaw gas by ISH or any other operator."

[10] Exhibit 30.02, tab 45, page 185.

[148] Dr. Boone set out key findings from his review. We have summarized them as follows:

- Of the 96 wells at Canadian Natural's Kirby North operations, bottomhole pressures at start-up exceeded 6 MPa in 41 wells, and only one well exhibited characteristics of possible fracturing.
- Any fracture generated at start-up would be water driven (condensed steam), of short duration (approximately one hour), and taking a small volume of steam (less than ten cubic metres).
- Diagnostic fracture injection test (DFIT) data from wells in the region around the KN06 box show "significant" stress contrasts in the upper McMurray shales or muds and the Wabiskaw Formation that would prevent the propagation of any fracture into the Wabiskaw.
- The collective leak-off potential of permeable zones, including McMurray reservoir sands and the "overlying McMurray B2 and B1 sequences," would act as a barrier to any start-up-generated fractures.
- Using the *APEGA Guidelines for Managing Risk* (APEGA risk guidelines), the calculated risk of a fracture generated at start-up reaching the Wabiskaw B gas zone is less than 0.1 per cent, and, because any such fracture would have limited dimensions, the risk of actually impacting the 10-01 well is less than 0.01 per cent.
- The consequence of a fracture generated at start-up that negatively impacted the 10-01 well is considered to be additional workover costs to manage water production, estimated to be between $10 000 and $100 000.
- Although the calculated risk (probability × consequence) is low enough that mitigation would not "normally" be required following the APEGA risk guidelines, "it is recommended that enhancements to pressure and injection rate monitoring for wells during the start-up process would be a more effective tool than monitoring with an observation well."

[149] To arrive at his conclusions, Dr. Boone

- assessed reported data from DFITs in the Kirby North and South, Jackfish, and Pike SAGD development areas (table 1 in Dr. Boone's report);
- assessed the "geologic description" of relevant formations in the KN06 box for the presence of permeable zones that could act as barriers or baffles due to their leak-off capacity;
- assessed operational parameters from start-up operations for Canadian Natural's Kirby North operations where MOP during start-up exceeded 6 MPa;
- using the assessed information, evaluated the likelihood of a fracture induced at start-up reaching the Wabiskaw B and causing fluid injected at start-up to reach the GOB gas zone; and
- calculated the likelihood and consequence of the risk and applied the APEGA risk guidelines to determine whether mitigation measures are necessary.

[150] ISH challenged Dr. Boone's report on the basis of his estimate of a fracture-closure-pressure (FCP) gradient for the McMurray sands of 13.1 kPa/m. ISH took issue with the estimate, saying it means that 90 per cent of the reported values for the McMurray sands in table 1 of Dr. Boone's report were lower than 13.1 kPa/m. ISH said the more appropriate approach is to use a more conservative 20th-percentile (P20) value, corresponding to 11.6 kPa/m. Using the 11.6 kPa/m value, ISH calculated that 20 per cent of wells in the KN06 box will exhibit induced fracturing at start-up. It said this is because the true vertical depth of the wells in the KN06 box, at 490 m, is shallower than those in the development areas identified in table 1.

[151] ISH suggested that if the MOP at start-up remains at 7 MPa, Canadian Natural will likely "push" the start-up pressures of all its KN06 wells above 6.5 MPa. ISH then said that using a true vertical depth of 490 m, the corresponding FCP gradient would exceed 13.3 kPa/m. As a result, it said, start-up-induced fracturing would occur in over 90 per cent of the wells in the KN06 box. To further support this argument, ISH pointed to a table labelled "Kirby North KN02-KN05 Circulation Maximum BHP Gradients" in Canadian Natural's July hearing submission. ISH said that of the 96 wells represented in that table, 4 have circulation maximum bottomhole pressure (BHP) gradients of 13.1 kPa/m or more, and of those, 1 well showed induced fracturing. That well had the highest circulation maximum BHP gradient, listed as 13.7 kPa/m. ISH said this demonstrates that the expected frequency of induced fracturing is 25 per cent, or one in four, for wells where the circulation maximum BHP gradient exceeds 13.1 kPa/m.

[152] In addition, in its original submissions (exhibit 29.01) and materials filed to support its request for this regulatory appeal, ISH referred us to Canadian Natural's application materials dated December 11, 2011, for its Kirby expansion project. ISH's consultants noted that in those materials, Canadian Natural said the minimum fracture pressure in the Wabiskaw B is 6.71 MPa.

[153] Finally, ISH said a 7 MPa MOP at start-up with a corresponding pressure gradient of 14.7 kPa/m is "largely above" the minimum stress gradient as estimated from regional DFIT data.

[154] ISH summed up its challenge to Dr. Boone's conclusions, saying that based on Canadian Natural's DFIT data and assuming a MOP of 7 MPa at start-up, "it is reasonable to believe that each KN06 well has a probability of at least ninety percent of inducing fractures." ISH concluded that

- a safety factor should be introduced by using the P20 value of 11.6 kPa/m;
- P20 should be used to calculate the FCP at the true vertical depth (490 m) of KN06 wells, resulting in a value of 5.7 MPa; and
- MOP at start-up in KN06 should be limited to 6 MPa.

[155] Canadian Natural provided its own GeoSim modelling. Canadian Natural said its modelling was conservative, based on input choices including

- focusing only on the mid-B1 mudstone as a containment barrier (so incorporating a stress contrast only at the mid-B1 mudstone);
- low leak-off;
- operating at highest observed rates (in previous start-up operations) for a full 14 days;
- single-fracture modelling;
- low pore and total compressibility; and
- no increase in fluid mobility due to heating.

[156] Canadian Natural's evidence was that, for this modelling, it developed a layered model of the KN06 geology and assigned reservoir properties using logs calibrated with core and geomechanical properties based on its experience modelling the McMurray. It used initial stress data for the mid-B1 mudstone based on a single minifrac test (minimum stress of 14.6 kPa/m) and for the McMurray post-B2 reservoir facies (sand zones) based on several minifrac tests (minimum stress of 13.1 kPa/m).

[157] In response to questions at the hearing, Canadian Natural said it assumed a weakened strength of the confining strata to account for the potential presence of fractures. It did not account for faulting because it had no evidence of faulting in the area of the KN06 box.

[158] Canadian Natural presented modelling results for its most conservative input, "most realistic" input, and worst-case scenario. The modelling results showed that fractures are possible at start-up at the expected MOP, injection rates, and injected-liquid volumes. In the worst-case scenario, leak-off in the non-reservoir zones was assumed to be zero and no poroelastic effect was introduced. The modelling showed that even in the worst-case scenario, the fracture would be contained to the McMurray zone for the entire 14-day model period with a MOP up to 7 MPa. Canadian Natural attributed this to higher leak-off capacity of the bottom-water and higher-water saturations in the McMurray post-B2 non-reservoir, which helps limit fracture size and increase the injection volume required to grow the fracture to the base of the B1 zone. In addition, Canadian Natural said the stress contrast in the mid-B1 mudstone provides a stress-containment barrier to limit vertical fracture growth. Finally, in Canadian Natural's view, the realistic case was that poroelastic effect will significantly limit fracture size to a height of less than 5 m and result in fracture closure after approximately 16 hours of injection at a pressure above 6.0 MPa.

[159] Canadian Natural said the modelling shows that under its approved start-up MOP (i.e., 7 MPa), the risk of fracture growth beyond the mid-B1 mudstone is extremely low. Canadian Natural also said there are three main mechanisms to inhibit or prevent fracture propagation from a wellbore in the

McMurray reservoir to the mid-B1 mudstone. Those mechanisms are leak-off, stress contrasts, and poroelastic-stress increase on steaming.

[160] Discussing its modelling, Canadian Natural said the actual geologic model of the McMurray post-B2 non-reservoir contains many mud layers, and even though these layers are not continuous barriers in terms of permeability, they would have a higher stress gradient than the McMurray post-B2 reservoir. As a result, they would also limit vertical growth of induced fractures. Canadian Natural also referred to its operational experience to support its modelling results. It said that well-pair configuration allows pressure observation during start-up. Canadian Natural also noted that wells usually do not initiate circulation at the same time, so the first well can be used to observe any fracture reaching it from the other well that is still in start-up mode. Canadian Natural's evidence was that "in all of the field cases identified with start-up pressures greater than 6 MPa, although potentially a high BHP existed for some time, no pressure interference was observed at the other well of the well pair, suggesting the fracture was very limited in size if present at all."

[161] ISH did not challenge the GeoSim modelling. In its reply submission, ISH referred to information supplied by Canadian Natural in response to specific ISH information requests. In particular, ISH said that interpreted in situ stresses for a well in the Kirby area and a well in the Jackfish project indicate that the fracture pressures in the McMurray are below 7 MPa. ISH went on to criticize Canadian Natural's favourable comparison of its 7 MPa start-up pressure with MOPs of other operators because it did not show if or how they are directly comparable.

Panel's Analysis and Findings

[162] We find Dr. Boone's report to be thorough and the methodology to be sound. Dr. Boone's key findings are persuasive and his recommendations reasonable.

[163] The GeoSim modelling does not reflect the heterogeneity within the McMurray up to and including the McMurray B1 mudstone. It is highly simplified. For example, it used a single value for the Poisson's ratio for the entire McMurray unit rather than assigning the different Poisson's ratios for the interbedded sand and mudstone units. However, we are satisfied that the simplifications and assumptions used by Canadian Natural do result in conservative modelling. We find the results are reasonable.

[164] Taking the above into account, we find that the evidence provided by Canadian Natural shows that there is a risk of induced fracturing at start-up. Indeed, the evidence clearly shows that induced fracturing in the McMurray should be expected. However, we find that, on balance, the evidence supports Canadian Natural's position that any fracture induced at start-up, even at 7 MPa, will likely not extend beyond the mid-B1 mudstone as long as certain operational parameters are respected. Our finding is particularly influenced by the evidence about the potential for leak-off in zones below the mid-B1 mudstone and the contrast in measured stress gradients between the McMurray shales/mudstones and the McMurray sands.

[165] Implicit in ISH's request for relief is the fact that Canadian Natural could start up wells in the KN06 box if the MOP was reduced to 6.0 MPa. Canadian Natural did not say that was not possible, but its evidence was to the effect that a 6.0 MPa limit is not practicable for operational reasons. We believe the evidence shows that economic factors are also a significant driver of Canadian Natural's desire to have the flexibility to use start-up pressures up to 7 MPa.

[166] We find that the key operational parameters during start-up to mitigate the induced-fracture risk are limited duration at pressures greater than 6.0 MPa and limited volume of injected liquids.

[167] Canadian Natural said that after receiving and reviewing Dr. Boone's report, it decided to commit to certain "enhancements" to its start-up process at the KN06 box. Canadian Natural described those measures in the following terms:

> a) A workshop with the KN06 area team is conducted at least 30 days prior to the KN06 startup, covering the following topics:
>
>   i) Hydraulic fracturing;
>
>   ii) KN06 in-situ stresses; and
>
>   iii) Previous Kirby North circulation startup illustrative examples above 6.0 MPa.
>
> b) Revise the circulation startup strategy such that when first attempting to initiate circulation, the BHP be limited to 6.0 MPa or less.
>
> c) If wells have reached 6.0 MPa but do not unload and establish circulation after 4 hours have elapsed, then BHPs above 6.0 MPa and up to 7.0 MPa may be used with:
>
>   i) A multi-disciplinary engineering team including production, geomechanics, and reservoir engineering expertise is made available to monitor the real time start up data for indications of hydraulic fracturing; and
>
>   ii) Following a revised circulation startup standard operating procedure (SOP).
>
> d) An engineer with geomechanics expertise should review rate and pressure records for several of the initial wells during start-up to test for an abnormal or unexpected fracturing behaviour at KN06.
>
> e) The surveillance graphs used to monitor the real time data are modified to include in-situ stresses for the BHP trends.[11]

[168] We find that Canadian Natural's commitment to enhanced procedures in the KN06 box will further lower any risk of pressure-induced fracturing during its start-up process.

[169] Finally, the 80-per-cent safety factor referred to by ISH applies to what the AER considers to be the shallow thermal area as defined in *Directive 086*. Kirby North is not in the shallow thermal area. In addition, the 80-per-cent safety factor does not apply to short-term exceedances of MOP. There is no basis in the applicable regulatory framework to apply an 80-per-cent safety factor here. We are not convinced that the evidence on the record in this proceeding provides a basis for establishing a different safety factor for the KN06 box.

[11] Exhibit 65.01, PDF page 27.

c) The 10-01 Well

[170] ISH is the licensee and operator of the 10-01 well. Canadian Natural owns the majority working interest in the well. The 10-01 well began production from the Wabiskaw B in 1994 and is designated to the Kirby Upper Mannville II Pool. The 10-01 well was shut in in 2004, pursuant to the GOB decision (GOB shut-in). ISH said in its oral evidence that the 10-01 well is 150 m from the KN05 box.

[171] Questions about potential wellbore integrity or other issues at the 10-01 well arose during the information request and response process in this proceeding. It was not among the original issues identified for the hearing.

[172] The commercial scheme approval for Canadian Natural's Kirby North project and section 7.8 of AER *Directive 078* (now *Draft Directive 023*) required Canadian Natural to ensure that all offset wells that might be affected by SAGD steam operations be thermally compatible. Because the 10-01 well was originally thermally non-compliant, Canadian Natural proposed abandoning the well or completing a workover to make it thermally compliant. The evidence shows that abandonment was Canadian Natural's preferred choice, but ISH rejected the abandonment option.

[173] Canadian Natural completed a workover of the 10-01 well in 2015 to make it thermally compliant and to maintain its ability to produce from the Wabiskaw B in the future. It said that "after consultation with both the AER and ISH, Canadian Natural executed work on the ISH 10-01 non-compliant well in January 2015 and instrumented the wellbore in March 2019 for the purpose of making it compatible with Canadian Natural's thermal operations." The 10-01 well was instrumented with pressure and temperature gauges to monitor the thermal integrity of the 10-01 well and to monitor the Wabiskaw B reservoir. It currently functions as a gas-monitoring well.

[174] ISH provided further details, saying, "The parties agreed the workover plans to the 10-01 Well, which were reviewed and accepted by the AER, and were conducted by CNRL."

[175] ISH alleged Canadian Natural is required to provide it with monitoring data from the 10-01 well by virtue of an agreement between the parties. ISH further alleged that Canadian Natural did not provide that information in a timely manner. ISH said it only received gauge data and interpretation for the period from March 11, 2019, to June 10, 2019, on August 14, 2020, after specifically asking for it through an information request in this hearing. Canadian Natural disputed this.

[176] ISH stated the data it received shows that the Kirby Upper Mannville II Pool has been compromised. It said that likely happened in 2015 during the workover.

[177] In its reply submissions, ISH submitted a report by WellTest Specialists (the WellTest report). It was prepared by D. Leech, who appeared as a witness for ISH at the oral hearing to speak to and answer questions about the 10-01 well issue. Mr. Leech concluded that GOB gas has been flowing around or

through perforations in the 10-01 well casing. He identified three possible alternatives for the pressure and temperature anomalies measured in the 10-01 well:

1) Gas channeling behind 10-01 casing, up hole to the Upper Mannville HH formation, which has two (2) ISH wells producing (16-35 & 07-27). Most probable case given apparent correlation of 16-35 production data to 10-01 pressure data.
2) Well has been surreptitiously tied in and gas has been stolen. Less probable, except that: a) pressure dynamics appear more hydraulic in nature than via dampened reservoir communication; and b) the hard shut-in does not reflect typical hydrating-off effects, the slow restriction of rates declining to zero. The author has experienced this unusual scenario twice to date.
3) Gas migrating into the Upper Mannville HH via a leaking packer at 16-35 (both formations perforated, dual completion). Discounted as the JT[12] cooling event clearly illustrates gas flowing within thermodynamic range of the subject 10-01 pressure gauge.[13]

[178] ISH asserted that the 10-01 wellbore is compromised and that gas is channelling behind the casing. It argued that the 10-01 wellbore would act as a path of least resistance for H_2S-contaminated steam to move up the wellbore to the Kirby Upper Mannville II Pool. From there, ISH submitted, nothing would prevent the contamination of the Kirby Upper Mannville HH Pool as sour gas channels further up the wellbore. ISH operates a non-GOB well in the Kirby Upper Mannville HH Pool at 00/16-35-074-09W4/2.[14]

[179] Canadian Natural responded that the cement bond log it ran after completing the workover in 2015 shows that gas cannot be channelling behind the casing. It suggested that GOB gas was being intentionally produced from the shut-in well. During oral questioning by Canadian Natural, Mr. Leech acknowledged that an additional alternative to the three he had identified is that the 10-01 well was being produced.

[180] Canadian Natural had not included the cement bond log or report as evidence in this proceeding. In exhibit 65.01 on page 15, there is a reference to an internal (Canadian Natural) interpretation of the cement bond log. Canadian Natural's interpretation was that over 50 per cent of the McMurray to Kirby Upper Mannville II Pool (Wabiskaw B) had a good cement bond and over 80 per cent of the Kirby Upper Mannville II Pool to the Kirby Upper Mannville HH (Grand Rapids Formation) Pool had a good cement bond.

[181] On October 2, 2020, we directed Canadian Natural to file the cement bond log and an interpretation report in this proceeding. Canadian Natural filed the cement bond log and a report prepared by an independent contractor (exhibit 81.01). The report concludes that the cement bond is "in the 100 percent range." The contractor did not appear at the hearing to speak to the evidence.

[12] The Joule Thomson ("JT" in Mr. Leech's evidence set out above) effect refers to the change in temperature observed when a gas expands while flowing through a restriction without any heat entering or leaving the system. It can cause a marked and sudden temperature decrease as gas flows through pores of a reservoir to the wellbore.

[13] WellTest report in exhibit 63.01, PDF page 53.

[14] See figure 24, exhibit 63.02, page 47.

[182] When asked at the hearing about the apparent discrepancy between the original cement bond log interpretation and the more recent interpretation, Canadian Natural's response was that cement bond log interpretation is subjective. It also said that "even with fifty or eighty percent of a good bond, these zones are hydraulically isolated, and there is no channel that exists behind the pipe."

[183] Canadian Natural also submitted Kirby North production performance data to support its position that the anomalies at the 10-01 well are not related to SAGD operations in the KN05 box.[15] Canadian Natural said if there was communication between the bitumen-bearing McMurray at KN05 and the GOB zone in the 10-01 well, it would have observed an unexplained loss of injection fluids. Its most recent *Directive 054* presentation to the AER for the KN05 box (2019; exhibit 48.02, page 658) is some support for its position. The water and steam rates parallel each other without the deviation of one from the other that would be expected if there was steam loss to the GOB zone.

[184] Finally, Canadian Natural referred to the pressure and temperature versus time plot in the WellTest Specialists report that was part of ISH's reply submission (10-01 plot). Canadian Natural said that the pressure buildup clearly shown in the 10-01 plot starting from a hard shut-in event beginning January 6, 2020, shows that the Kirby Upper Mannville II Pool remains isolated from the McMurray Formation.[16]

[185] By the time of the oral hearing in this proceeding, the parties had agreed that the temperature and pressure anomalies seen in the 10-01 well plot do not correlate to Canadian Natural's SAGD operations in the KN05 box. The parties had also agreed that the data shows pressure depletion in the Kirby Upper Mannville II Pool, from approximately 1100 kPa to 800 kPa over a five-year period.

[186] ISH maintained that the 10-01 well and Kirby Upper Mannville II Pool have been compromised and gas is channelling behind the casing. ISH argued that the consequence of the apparent production of gas from the Kirby Upper Mannville II Pool is not relevant to this proceeding. Canadian Natural appeared to agree. ISH also argued that the manner of production is relevant. While Canadian Natural continued to take the position that the 10-01 well has not been compromised, it acknowledged that there is an issue that requires further investigation. Canadian Natural said that if it is a wellbore cement integrity issue, it could be repaired.

[187] The parties also agreed that more information is needed to understand what is causing the apparent depletion of the Kirby Upper Mannville II Pool and what is required to deal with it.

Panel's Analysis and Findings

[188] We are not persuaded that the cement bond log run in 2015 proves conclusively that there is no integrity issue now with the 10-01 well.

[15] The KN05 box is adjacent to the KN06 box—to the east.

[16] Exhibit 63.02, PDF page 59; and exhibit 48.02, PDF page 48.

[189] In addition, and of particular concern, is the fact that the 10-01 plot shows that the pressure measured in the Wabiskaw B as of July 30, 2020, appears higher than when the pressure and temperature gauges were installed and stabilized in March 2019. Where the Wabiskaw B had been steadily losing pressure over a five-year period, the data shows that trend has now reversed. This suggests that the Wabiskaw B is gaining pressure support from somewhere. Whether it is a result of KN05 box operations or through communication with another zone in the KN06 box or some other process, we do not have the evidence necessary to draw a conclusion. In our view, existing communication between the Wabiskaw B at the 10-01 well and another zone in either the KN06 or KN05 box is a real possibility that must be investigated further before SAGD operations can commence in the KN06 box. We address this further below in our discussion about reasonable mitigation.

[190] In addition to the observations made on the record by the parties, we note that the pressure trend in the 10-01 plot shows a reduction in pressure in the Wabiskaw B between mid-March 2019 (after the gauge had settled) and January 6, 2020, at the time of the hard shut-in. In that time period, there were numerous coincident spikes in temperature and pressure that seemed to resolve during the time bracketed by "substitution manual data" and "end data substitution," the latter happening on April 9, 2019. It appears that the temperature and pressure spiking began again after April 9, 2019. Insufficient information is available to determine whether this apparent coincidence is relevant to the concerns about the 10-01 well.

[191] We find that the 10-01 well may be a potential pathway for steam from the McMurray to the Wabiskaw B. We base our finding on the points on which the parties agree and on the evidence on the record relating to the 10-01 well—in particular, the 10-01 plot.

3) Need for an Observation Well – Other Mitigation Measures

[192] Need for an observation well was the last issue initially identified for the hearing. It became clear as the record developed that the third issue is better described more broadly as the need for mitigation instead of or in addition to an observation well.

[193] In light of our conclusions above and the overarching questions, we must consider what is reasonably required of Canadian Natural in the circumstances to avoid or mitigate the risk of direct and adverse effects to ISH arising from Canadian Natural's operations in the KN06 box. Specifically, we must consider what is reasonably required of Canadian Natural to address the risk of

- induced fractures at start-up that reach the Wabiskaw B;
- loss of steam containment over the production life of the KN06 box, allowing steam to find a path to the Wabiskaw B; and
- steam and/or non-gaseous fluids reaching the Wabiskaw B through the 10-01 wellbore.

[194] In addition to effectiveness and practicability of various mitigation measures, we also considered the nature and consequence of the potential adverse effects to be mitigated and the economic evidence presented by the parties.

Mitigation Measures

[195] ISH's submissions early in this proceeding included a request that Canadian Natural be required to drill a SAGD observation well (observation well) to monitor for loss of steam containment from the McMurray. ISH's position evolved over the course of this proceeding. In its response to a request from the AER for a description of the specific relief it seeks, ISH said:

> ISH requests that the AER rescind CNRL's approval 11475EE for the KN06 Box, pending further review of risks and mitigative requirements. In the alternative, ISH requests that the AER require that CNRL:
>
> (a) Fully address the risks of steaming in KN06 pad, including assessment of the 10-01 Well prior to commencing steaming operations;
>
> (b) Reduce the start-up maximum operating pressure for KN06 to 6.0 MPa;
>
> (c) Develop a monitoring strategy for start-up and continuous SAGD operations for operations in the vicinity of the KN06 Box that will monitor confining strata and <u>may include observation wells to replace the 10-01 Well</u> as well as 4D seismic. [emphasis added]
>
> In the event that the AER does not rescind CNRL's approval 11475EE for the KN06 Box, ISH requests that the following specific changes be made to Approval 11475EE:
>
> Appendix B be added to the Approval
>
> ISH asks that the AER add Appendix B to Approval 11475EE, which will be comprised of the map at Figure 1-2 of CNRL's application, found at PDF 20 of Exhibit 2.01 and attached to these IR Responses at Tab 4.
>
> Paragraph 8 of Approval 11475EE be amended as follows:
>
> 8(a) Prior to drilling SAGD wells within 300 metres of the following wells, the Operator shall submit, for AER review and approval, an assessment of the impact thermal operations may have on the wells and any plans required to mitigate risk of reservoir fluid containment:
>
> 00/10-18-074-07W5 00/11-26-074-08W4 100/10-01-075-09W4
>
> 00/11-24-074-09W4 00/16-19-075-08W4
>
> 8(b) Prior to drilling SAGD wells located in the KN06 Box outlined in Appendix B, the Operator shall conduct an assessment of well 100/10-01-075-09W4 integrity; if necessary conduct operations to repair the well; and provide the AER with an independent report that confirms the well integrity during SAGD operations.
>
> 8(c) Prior to starting steam circulation in the KN06 Box outlined in Appendix B, the Operator shall develop a monitoring strategy for start-up and continuous SAGD operations that will monitor confining strata <u>and may include observation wells to replace the 100/10-01-075-09W4 Well</u> as well as 4D seismic, and shall submit this monitoring strategy to the AER for review and approval. [emphasis added]
>
> Paragraph 9 of Approval 11475EE be amended as follows:
>
> 9(a) The bottomhole injection pressures for the approved drainage patterns within the development area located outlined in Appendix A must not exceed 6000 kPa (gauge), except during the startup when CNRL may have a bottomhole injection pressure of up to 7000 kPa (gauge) for a

maximum duration of 14 days in order to displace liquid in the wellbore to commence circulation, with the exception of the area set out in paragraph 9(b).

9(b) The bottomhole injection pressure for the approved drainage patterns SAGD wells drilled within the KN06 Box outlined in Appendix B must not exceed 6000 kPa (gauge).

[196] In its reply submissions, ISH referred to the use of 4D seismic to monitor for potential loss of containment. It provided some evidence of the use of 4D seismic as standard industry practice for monitoring steam-chamber growth and movement. ISH said, “In the absence of down hole temperature and pressure monitoring away from the SAGD well pairs, 4D seismic surveys can ensure zones outside of the intended target are not breached.”

[197] In its request set out above, ISH included 4D seismic as one of a number of tools Canadian Natural could use as part of a monitoring strategy. It also identified an observation well or wells as possible elements of a monitoring strategy, although in final argument ISH seemed to revert to the request that Canadian Natural be required to drill an observation well or wells.

[198] Canadian Natural strongly opposed the proposition that it should be required to drill an observation well. It said that it uses observation wells to monitor temperatures and other parameters to optimize performance of SAGD projects and that an observation well is not required by regulation or its Kirby North approval. It also said its operational experience with Kirby South has led it to conclude that observation wells are not useful for optimizing production in the Kirby area.

[199] Canadian Natural also argued that an observation well is not the right tool for identifying the potential movement of steam or other fluid from the McMurray into the Wabiskaw B, particularly because it would provide only a point source for pressure and temperature data near the observation wellbore. In addition, Canadian Natural said that because of the limited areal scope of the data provided by observation wells, they are not effective for prevention. On that issue, ISH responded that an observation well could provide information of an impending risk if positioned in the right location. It also suggested that Canadian Natural could drill more than one observation well.

[200] Finally, Canadian Natural said the cost to drill and operate an observation well far outweighs any potential benefits. Its evidence was that the cost would be greater than $600 000, which ISH did not dispute.

[201] Canadian Natural submitted that instead of an observation well, a gas-monitoring well—specifically, the 10-01 well—would be more useful for identifying impending risk. Canadian Natural said a gas-monitoring well could be used for monitoring during start-up and production. It said that “if downhole pressures and temperatures indicate the highly unlikely event of a water-filled hydraulic fracture propagating into the GOB zone, the KN06 well undergoing steam circulation initiation could be shut in, until a thorough review of relevant data could be completed.”

[202] Canadian Natural said that during the operational life of the KN06 box, "increased surveillance of pressure and temperature from the existing wells in the Mannville II Pool can show if the zone has been impacted by the migration of reservoir fluids."

[203] ISH did not say a gas-monitoring well would not be useful or effective as mitigation. ISH's submissions focused rather on the suitability of the 10-01 well for monitoring, primarily because of what it described as the "integrity issues" with the well.

[204] Canadian Natural also listed preventative controls that will be in place during start-up and operations of the KN06 well pairs. Monitoring in real time will include bottomhole pressures and temperatures, surface line pressures and temperatures, steam-injection rates, and gas-injection rates. The preventative measures identified by Canadian Natural are alarms and steam-injection shutdown to ensure operations remain below the approved MOP—specifically, the 7.0 MPa at start-up.

[205] Canadian Natural said it is prepared to commit to what it described as enhanced measures to monitor for and mitigate risk of induced fracturing at start-up. Those measures are set out above.

[206] Finally, with respect to the suggestion that 4D seismic be used for further evaluation or monitoring, Canadian Natural acknowledged 4D seismic as a potential monitoring tool. It also said it intends to conduct 4D seismic over the life of the KN06 operations as a means of optimizing bitumen recovery. However, Canadian Natural stated that 4D seismic should not be relied on to monitor the Kirby Upper Mannville II Pool because it is conducted infrequently and is expensive. As well, the Wabiskaw B is already gas saturated, so any potential steam/gas impacts within that zone would be extremely difficult to observe with 4D seismic.

Nature and Consequences of Potential Adverse Effects, and Economic Considerations

[207] ISH did not explicitly identify a consequence it would suffer if start-up-induced fractures reached the Kirby Upper Mannville II Pool, providing pathways for steam to enter.

[208] ISH did say that the consequence of steam reaching the Wabiskaw B during the production life of the KN06 box—referring specifically to the 10-01 wellbore as the most likely path for steam—is that the currently sweet gas in the Wabiskaw B would be contaminated with H_2S. As noted in the GOB decision, one known effect of exposing bitumen-bearing sediments to steam over time is the generation of H_2S through aquathermolysis. ISH said any steam that reaches the GOB zone after start-up and during the production life of the KN06 box will bring H_2S and sour the GOB gas.

[209] ISH further submitted that it is not in a position to produce sour gas. Specifically, ISH's evidence was that not all of its wells and facilities in the GOB zone are equipped to handle sour gas.

[210] ISH also said that if the gas in the Kirby Upper Mannville II Pool were to be soured, it would pose a safety risk at the 10-01 well. Although ISH made some submissions on the point, it did not provide

evidence about the likelihood of a safety risk materializing or the magnitude of potential consequences. Nor did it provide evidence to show that if monitoring showed sour gas contamination in the Kirby Upper Mannville II Pool, it could not take steps to mitigate any resulting risk before recommencing production.

[211] ISH calculated the current net present value of the remaining recoverable gas in the Kirby Upper Mannville II Pool to range from $1 751 000 at a 5 per cent discount rate if the wells were on production in 2021 to $3 264 000 at a 0 (zero) per cent discount if the wells were on production in 2038. Those numbers are based on remaining reserves of 3170 MMcf (gross) accessible by ISH's four wells (all currently shut in) in the Kirby Upper Mannville II Pool. Key variables are the restart date of production and the discount rate. ISH said its calculation reflects the additional Crown royalty of 10 per cent that would be imposed to account for the GOB royalty adjustment applicable in respect of ISH's production that was shut in due to the GOB decision.

[212] ISH included reserves in both the Kirby Upper Mannville II and HH Pools to calculate the consequences of a breach resulting in souring of its gas resources. It calculated the monetary consequences at $2 000 000 at a net present value of 10 per cent. ISH did not provide evidence specifically to support or show how it calculated this figure. It included the HH Pool reserves on the basis of its hypothesis about where gas from the 10-01 well has been flowing.

[213] On behalf of Canadian Natural, Dr. Boone said the consequence if a start-up-induced fracture were to breach the Wabiskaw B reservoir would be commercial. He said there would be additional costs to deal with water introduced to the Wabiskaw B through any induced fractures from the McMurray. He estimated those costs at between $10 000 and $100 000. ISH did not challenge this point. It is also important to note that ISH and Canadian Natural are partners in the Kirby Upper Mannville II Pool—ISH at 46.25 per cent and Canadian Natural at 53.75 per cent.

[214] Canadian Natural did not dispute that H_2S contamination of the Kirby Upper Mannville II Pool is a potential consequence of steam from the McMurray reservoir reaching the Wabiskaw B during the producing life of the KN06 box. Canadian Natural said that in the unlikely event the Wabiskaw B gas in the Kirby Upper Mannville II Pool were soured, the consequence would be financial only. It would cost more to produce the gas.

[215] Canadian Natural did dispute ISH's inclusion of the Kirby Upper Mannville HH Pool in its calculation of the financial impact of a breach of containment resulting in souring of its gas resources. Canadian Natural said there is no evidence of a flow connection between the Kirby Upper Mannville II and Kirby Upper Mannville HH Pools. Canadian Natural also said it is not appropriate to include the value of any gas resources other than the Kirby Upper Mannville II Pool because they are not "appropriate" to the scope and issues in this hearing.

[216] Canadian Natural calculated the net present value to itself and ISH, as the mineral owners, of the remaining recoverable gas in the Kirby Upper Mannville II Pool at between −$16 000 and $450 000 at a net present value of 10 per cent. Canadian Natural used a material balance analysis to calculate low- and high-value cases. It calculated its low-value remaining recoverable reserves to be $32 \times 10^6 m^3$ (32 million cubic metres, which converts to 1130 MMcf). Its high value was calculated to be $67 \times 10^6 m^3$ (67 million cubic metres, which converts to 2366 MMcf).

[217] Finally, in its responses to an AER information request, Canadian Natural provided information about potential costs of monitoring and detection options. Those are found in table 5-1 of exhibit 65.01, which is reproduced below.

Table 5-1 Alternatives to Monitor and Detect Possible Impacts to Gas over Bitumen

Potential Impact to GOB zone	Monitoring and Detection Method	Options Available	Pro-Active or Reactive Monitoring	Cost to Monitor and Detect	If anomalies detected, probable next step?	How would the impact be mitigated?	Cost of Mitigation?
Hydraulic fracture of water into GOB zone	Enhanced monitoring of injection rates and pressures	See IR#8	Proactive	$10,000	Reduce injection rate and pressure	Decreased likelihood of fracturing Minimize potential volume and duration of hydraulic fracture	no additional cost
Migration of reservoir fluids into the GOB zone	Increase the surveillance of existing GOB wells in the Kirby Upper Mannville II pool	monitor the existing 100/10-01 wellbore	Proactive (short term) Reactive (long term)	no additional cost	Confirm the response is not related to a well integrity concern ($50,000 - $100,000 / well)	Treat gas at wellhead	$100,000 - $1,000,000
		install downhole pressure and temperature gauges in 3 additional wells	Proactive (short term) Reactive (long term)	$150,000 (3 wells @ $50,000 / well)			
Migration of reservoir fluids into the GOB zone	4D seismic	shoot 4D seismic	Reactive (long term)	$~10,000 (additional processing and interpretation time to include GOB zone in 4D seismic analysis)	Confirm the response is not related to a well integrity concern ($50,000 - $100,000 / well)	Treat gas at wellhead	$100,000 - $1,000,000

Panel's Analysis and Findings

[218] The regulatory and legal framework for this proceeding establishes our role. Because we have found that ISH, as the owner of mineral rights directly over the KN06 box, may be directly and adversely affected by Canadian Natural's proposed operations in the ways described above, we must determine whether there are reasonable steps that may be taken to avoid and mitigate those impacts. For our purposes we have determined that what is reasonable in the circumstances depends on the nature of the potential effects, practicability, effectiveness, and costs/benefits.

[219] We conclude that the nature of the potential adverse effects to ISH are commercial and, more particularly, monetary in nature. However, it is the AER's mandate to ensure the efficient, safe, orderly, and environmentally responsible development of energy resources in Alberta. Unnecessary harm to energy resources is not consistent with efficient, safe, and orderly development.

[220] The *REDA General Regulation* requires us to consider the economic impacts of Canadian Natural's approved operations. In this case, ensuring efficient, safe, and orderly development while

considering economic impacts means ensuring a balance between costs and benefits of mitigation measures. We are not required, as suggested by ISH, to protect its resources no matter what the cost.

[221] As noted above, *OSCA* establishes mechanisms to ensure owners have the opportunity to obtain the owner's share of production from any pool. ISH has had that opportunity and is also being compensated, through GOB royalty adjustments, for the lost opportunity due to the GOB shut-in. ISH will have the opportunity to obtain its share of additional production from the Kirby Upper Mannville II Pool in the future.

[222] Finally, in terms of the regulatory framework, we find support in and are informed by the GOB decision, in which the EUB found that where souring of GOB is a risk, it is a monetary one that is compensable, and the public interest lies in giving priority in time to bitumen production.

[223] ISH specifically asked that if we do not revoke the application, we require Canadian Natural to drill an observation well or wells. ISH indicated that an observation well would have to be in the right location to provide information to help identify the risk of loss of steam containment and migration of steam into the Wabiskaw B from the McMurray over time. It provided no evidence about how the right location would be selected. There was some suggestion of multiple observation wells, but in light of ISH's specifically requested relief, we do not give this suggestion any real weight.

[224] We are not convinced that an observation well would be useful for mitigating risk to ISH's gas resource. Monitoring wells are located to provide data to inform optimization of a particular SAGD development, not to provide an early warning system about the potential for encroachment of a steam chamber on specific infrastructure such as a well. The data monitoring that wells provide is also highly localized, the potential exists for non-uniform steam-chamber growth, and we cannot be certain where steam might encounter a path of lesser resistance through to the Wabiskaw B over time. Finally, the cost of a single SAGD monitoring well is also out of proportion to its potential benefits. We will not require Canadian Natural to drill an observation well.

[225] ISH did not challenge the effectiveness of using existing gas wells for monitoring (with the caveat noted above about potential integrity issues with the 10-01 well). ISH requested the use of 4D seismic as a monitoring tool.

[226] We believe that a gas-monitoring well can provide information to show that a risk is imminent where there is an unexplained increase in temperature or pressure, for example. For this to be effective for monitoring and mitigation, Canadian Natural would have to act on such information promptly. In addition, if the 10-01 well is to be used as a gas-monitoring well, the cause of the temperature and pressure anomalies seen in the 10-01 plot must be investigated further to:

1) rule out the possibility of an integrity issue with that well and
2) confirm that the monitoring data obtained from that well is a reliable source of information about the risk of encroachment of steam that may impact the Wabiskaw B.

[227] We find the following risk-mitigation measures are reasonable in the circumstances:

1) Canadian Natural's proposed enhancements to its start-up measures are practicable, appropriate, and cost effective. Their effectiveness for monitoring and mitigation was not seriously challenged.
2) Ongoing monitoring after start-up during the operational life of the KN06 box using existing gas wells and such 4D seismic as Canadian Natural acquires to optimize bitumen recovery is also practicable, appropriate, and cost effective.

[228] ISH raised concerns about the 10-01 well in the context of the risk of fractures or other breach of any barrier(s) between the McMurray bitumen reservoir and the Wabiskaw B. We dealt with that specific question above. We have found that the 10-01 well may be a potential pathway for steam from the McMurray to the Wabiskaw B.

[229] In addition, in light of the as yet unexplained anomalies in the pressure and temperature data from the 10-01 well that were filed in this proceeding, we find that well may not currently be suitable for monitoring. As noted by both parties, further work is required to determine the cause of those anomalies and whether any repairs are necessary.

[230] The amendments to Canadian Natural's amended approval, as set out in appendix 2, are reasonable and appropriate in the circumstances.

Conclusion

[231] We have found that Canadian Natural's proposed operations in the KN06 box, as permitted by the amended approval, may cause direct and adverse effects to ISH. We have also found that there are reasonable steps that may be taken to avoid and mitigate those effects.

[232] For the above reasons, the AER's decision to approve Canadian Natural's application 1909395 and issue the amended approval (11475EE) is varied by the conditions in appendix 2. In addition, the panel expects Canadian Natural to adhere to all the commitments it made to the extent that those commitments do not conflict with the terms of its AER approvals; any other approval or licence affecting the project; or any law, regulation, or similar requirement that Canadian Natural is bound to observe.

Dated in Calgary, Alberta, on January 13, 2021.

Alberta Energy Regulator

Cecilia Low, B.Sc., LL.B., LL.M.
Presiding Hearing Commissioner

Claire McKinnon, LL.B.
Hearing Commissioner

Brian A. Zaitlin, Ph.D., P.Geol., C.P.G.
Hearing Commissioner

Appendix 1 Hearing Participants

Principals and Representatives (Abbreviations used in report)	Witnesses
Canadian Natural Resources Limited (Canadian Natural) J. Jamieson, Legal Counsel	G. Iannattone J. Lavigne S. Sverdahl Dr. X. Wang P. Thomsen D. Walters Dr. T. Boone R. Craig M. Scrimshaw D. Ollenberger
ISH Energy Ltd. (ISH) L. M. Berg, Legal Counsel	V. Giry D. Leech P. Vermeulen E. Mathison J. Clee B. Thompson O. Lewis E. Ward
Alberta Energy Regulator staff A. Hall, AER Counsel S. Poitras, AER Counsel S. Harbidge T. Rempfer S. Botterill L. Shen E. Galloway D. Campbell A. Shukalkina T. Wheaton T. Turner	

Appendix 2 Summary of Conditions and Commitments

Conditions generally are requirements in addition to or otherwise expanding upon existing regulations and guidelines. An applicant must comply with conditions, or it is in breach of its approval and subject to enforcement action by the AER. The amendments to the conditions in approval 11475EE are summarized below.

The hearing panel has given weight to the commitments Canadian Natural said it was prepared to make to mitigate induced-fracture risk at start-up. While the AER considered these commitments in arriving at its decision and expects the applicant to comply with the commitments made, these commitments do not constitute conditions. The commitments are summarized below.

New Conditions

- Prior to drilling SAGD wells in Pad KN06 in section 01-075-09W4M in the development area outlined in Appendix A (of the approval), the Operator shall:
  - Investigate the cause of the temperature and pressure data anomalies observed in the 00/10-01-075-09W4/0 well in the Wabiskaw, including investigations for any fluid movement behind the production casing across the Clearwater caprock between the Kirby Upper Mannville II Pool and the Kirby Upper Mannville HH Pool in the 00/10-01-075-09W4/0 well.
  - Submit a report to the AER's satisfaction summarizing the results of the investigation.
  - Remediate any identified cause(s) of the anomalies as directed by the AER.
- Prior to starting steam circulation in Pad KN06 within the development area outlined in Appendix A, the Operator shall submit a monitoring strategy satisfactory to the AER for continuous SAGD operations.
  - The strategy should provide for monitoring of the confining strata and may include a gas monitoring well, or wells, in addition to the 00/10-01-075-09W4/0 well.
  - The strategy should include the use of interpreted maps and/or cross sections of 4D seismic data where it is available.
- Monitoring data shall be provided to the AER in the Operator's annual *Directive 054: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes* performance report.
- The bottomhole injection pressures for the approved drainage patterns (except Pad KN06) within the development area outlined in Appendix A must not exceed 6000 kPa (gauge), except during start-up when the Operator may have a bottomhole injection pressure of up to 7000 kPa (gauge) for a maximum duration of 14 days in order to displace liquid in the wellbore to commence circulation.
- For Pad KN06, the bottomhole injection pressures must not exceed 6000 kPa (gauge), except if after 4 hours of injection at start-up the wellbore does not unload and establish circulation, then the

Operator may have a bottomhole injection pressure of up to 7000 kPa (gauge) for a maximum duration of 14 days in order to displace liquid in the wellbore to commence circulation.

- During start-up at bottomhole injection pressures above 6000 kPa (gauge) and up to 7000 kPa (gauge), the Operator shall monitor the real time start-up data, including injection rates and bottomhole injection pressures, for indications of loss of containment of injection fluid. If the Operator identifies any indication(s) during start-up of loss of containment of injection fluid, it shall report it to the AER within 24 hours.
- In its annual *Directive 054* performance report, the Operator shall provide surveillance graphs used to monitor the real time data, which includes in situ stresses for the bottomhole pressure trends, for start-up SAGD operations in Pad KN06 within the development area outlined in Appendix A.
- In its annual *Directive 054* performance report, the Operator shall provide interpreted maps and/or cross sections of 4D seismic data, if available, to assist in monitoring the growth of the steam chamber within the McMurray, and identify any effects on the overlying gas zone in the Kirby Upper Mannville II Pool.

- During SAGD operations at Pad KN06, the Operator shall:
  - monitor temperature and pressure data in the Wabiskaw at the 00/10-01-075-09W4/0 well, and
    - if any anomaly is observed, report it to the AER within 24 hours of identifying the anomaly, and submit to the AER a plan to address the anomaly as soon as possible, and
    - submit the temperature and pressure data in its annual *Directive 054* performance report, and
  - monitor the Wabiskaw in the 00/10-01-075-09W4/0 well for communication between the McMurray and Wabiskaw through cement behind the production casing and
    - if any anomaly is observed indicating well/cement integrity issues in the 00/10-01-075-09W4/0 well, report it to the AER within 24 hours of identifying the anomaly and submit to the AER a plan to address the anomaly as soon as possible, and
    - submit the data in its annual *Directive 054* performance report.

Commitments by Canadian Natural Resources Limited

- A workshop with the KN06 area team is conducted at least 30 days prior to the KN06 startup, covering the following topics:
  - Hydraulic fracturing;
  - KN06 in-situ stresses; and
  - Previous Kirby North circulation startup illustrative examples above 6.0 MPa.
- Revise the circulation startup strategy such that when first attempting to initiate circulation, the BHP be limited to 6.0 MPa or less.
- If wells have reached 6.0 MPa but do not unload and establish circulation after 4 hours have elapsed, then BHPs above 6.0 MPa and up to 7.0 MPa may be used with:
  - A multi-disciplinary engineering team including production, geomechanics, and reservoir engineering expertise is made available to monitor the real time start up data for indications of hydraulic fracturing; and
  - Following a revised circulation startup standard operating procedure (SOP).
- An engineer with geomechanics expertise should review rate and pressure records for several of the initial wells during start-up to test for an abnormal or unexpected fracturing behaviour at KN06.
- The surveillance graphs used to monitor the real time data are modified to include in-situ stresses for the BHP trends.

Appendix 3 Reasons for Rejecting ISH's Motion

Alberta Energy Regulator

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Proceeding 397

November 12, 2020

By email only

ISH Energy Ltd.

Attention: Laura-Marie Berg

RE: Regulatory Appeal 1927181
Motion to Reopen the Hearing

Dear Counsel:

I am writing on behalf of the Alberta Energy Regulator (AER) panel of hearing commissioners (the panel) assigned to this proceeding.

On November 6, 2020, ISH Energy Ltd. (ISH) filed a motion pursuant to section 44 of the *Alberta Energy Regulator Rules of Practice* seeking leave to submit a written legal argument clarifying its position on the following three legal issues (the Motion):

a. The Proceeding being in the nature of a hearing *de novo*;
b. Application of the reasonableness test, if applicable; and
c. Discharge of the relevant onus.

The panel has reviewed the Motion, Canadian Natural Resources Limited's (Canadian Natural) response filed November 9, 2020, and ISH's reply filed November 10, 2020.

The panel has decided to deny the Motion, for the reasons that follow.

<u>Background of Regulatory Proceeding 397</u>

This proceeding is a regulatory appeal commenced by ISH when it filed a request for regulatory appeal in February 21, 2019. Both parties had the opportunity to file extensive written submissions in the course of that process.

The panel identified the issues for this appeal by way of a letter dated April 30, 2020, after soliciting comments from the parties on the issues. Both parties agreed with the panel's description of the issues. The panel established a process that included submissions from both parties and reply submissions from ISH. It also included a formal information request and response process.

Eventually, an electronic hearing was scheduled to be held from October 13 – 16, 2020. Each party was given the opportunity to file a written summary of its direct evidence, orally present its direct evidence, and question the other party's witnesses. ISH also provided rebuttal evidence.

In a letter dated October 6, 2020, the panel set out the schedule for the oral portion of the hearing. It advised the parties that "[t]he panel would like the parties to be prepared for final argument upon finishing the evidentiary portion of the hearing." (emphasis added)

In remarks at the opening of the oral hearing, the panel chair advised the parties that:

> We'll decide the mode and timing for final argument at the conclusion of the evidentiary portion of the hearing, but we plan to give counsel for the parties an opportunity to share their views on mode and timing for final argument at the opening of the first afternoon session tomorrow…
>
> I can tell you that I think our -- our preference all things being equal would actually be to have online oral argument at the end of the week. (emphasis added)

The panel did solicit the parties' views on the mode and timing for final argument on the second day of the oral hearing. ISH expressed a preference for written argument on what it described as an expedited basis – about one week after the close of the evidentiary portion of the hearing. It referred to the "heavily visual" nature of the hearing as the basis for saying written argument would be more appropriate.

Canadian Natural said it was prepared to proceed with oral argument at the close of the evidentiary portion of the hearing.

Before the commencement of proceedings on the third day of the hearing, the parties were advised in written correspondence by the panel's counsel that the panel had decided to proceed with oral argument on the last scheduled day of the hearing. The parties were advised that if they wished to refer to diagrams, charts or other visual hearing submissions in the course of their oral argument, they were welcome to ask to have those documents displayed electronically for the parties and the panel to see.

The evidentiary portion of the hearing concluded on Thursday, October 15, 2020. Closing arguments commenced Friday, October 16, 2020, shortly after 9 am. ISH also took the opportunity to present an argument in reply to Canadian Natural's closing argument. The record of the proceeding was closed on the afternoon of October 16, 2020.

Background of the Motion

On November 5, 2020, the panel was notified by its counsel that they had received a letter from ISH, where ISH conveyed a desire to make additional submissions on three topics: the nature of the proceeding, the standard of review, and the onus.

On November 6, 2020, the panel's counsel notified the parties, on behalf of the panel, that, as the hearing was closed (for both evidence and argument), ISH would need to bring a motion for the panel's leave to file additional submissions.

Motion Submissions

On November 6, 2020, ISH filed the Motion, asking for the panel to accept further written legal argument clarifying ISH's position about the law on the three issues cited above. ISH's grounds for the Motion were that, upon review of the transcript, it was evident that certain legal issues required clarification. ISH submitted that, as the proceeding was in the nature of a hearing *de novo*, a standard of review did not apply. It followed that the parties' submissions on the application of a reasonableness test in the context of the proceeding required clarification. Finally, on the issue of onus, the submissions were not clear as to whether the onus is only on the appellant, or whether it shifts back to the project proponent.

On November 9, 2020, Canadian Natural filed its response to the Motion. Canadian Natural objected to the Motion on the basis that procedural fairness had already been served in the proceeding. Canadian Natural noted that, on October 6, 2020, the hearing panel issued the schedule for the hearing which indicated that both parties would be provided with the opportunity to present oral closing arguments (one hour each) on Friday, October 16, 2020. ISH was also afforded the opportunity – which it took – to make a 30-minute reply argument. Canadian Natural submitted that both parties had the same opportunity to raise and address what they believed to be the relevant legal issues, including the issues ISH wants to provide further argument on. Canadian Natural submitted that it strongly disagreed with the rationale ISH provided to support its motion, and that ISH should not be allowed to revisit its closing argument merely because it wishes that it had made different or clearer submissions in the first instance. Finally, Canadian Natural stated that it would be prejudiced if the Motion was granted and the panel's decision on the regulatory appeal was delayed.

On November 10, 2020, ISH responded to Canadian Natural's argument by submitting that Canadian Natural neglected to address ISH's primary concern that the arguments from both parties were unclear regarding the implications of what a hearing *de novo* means for the standard of review, and the relevant law on the shifting of onus in AER proceedings, and when that would occur - a point which ISH raised briefly, and Canadian Natural did not address. ISH submitted that the panel would benefit from brief clarification submissions from both parties.

Analysis

The Motion's grounds are that a review of the transcript shows that "it is evident that certain legal issues require clarification." However, neither party referred to any legal authority on which the panel could refer to when deciding whether to grant the Motion. Accordingly, the panel must decide the Motion on the principles of fairness.

The panel is of the view that ISH was provided with ample notice that the closing arguments would be made orally, and would occur on Friday, October 16, 2020. This was a hearing attended by two experienced counsel, supported by full teams from their sophisticated, industry clients. After the submission of written materials, the completion of multiple information requests, and a full hearing, the grounds for re-opening a hearing to clarify legal submissions is, and should be, a high bar. Only under exceptional circumstances should a party be able to clear this hurdle.

ISH did not provide any substantive arguments to suggest that its situation was exceptional, or reasons why it could not adequately address in the hearing the legal issues it now seeks to clarify through further submissions. Onus, standard of review, and hearings de novo are well tread areas of law, and as the panel has noted, there was ample opportunity for the parties to specifically raise and address any one or all of them and to make submissions accordingly in their final argument. This is not a case where new legislation or case law became available, which would not have been available to the parties at the time of the hearing.

In the absence of compelling reasons from ISH, and in light of the potential prejudice to Canadian Natural and the AER's interest in promoting finality in its proceedings, the panel has decided to deny the Motion.

Regards,

<*original signed by*>

Tammy Turner
Hearing Coordinator, Hearing Services

cc: JoAnn P. Jamieson, Canadian Natural Resources Limited
Karen Lilly, AER Regulatory Applications
Alana Hall and Scott Poitras, AER counsel for the panel