Canadian Natural Resources Limited

Application to Amend Commercial Scheme Approval No. 11475 for Pads KN08 and KN09 at Kirby North In Situ Oil Sands Development

May 8, 2024

Alberta Energy Regulator
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Abbreviations

AER	Alberta Energy Regulator
Canadian Natural	Canadian Natural Resources Limited
DFIT	diagnostic fracture injection test
EUB	Alberta Energy and Utilities Board
EUB 1998 inquiry	*EUB Inquiry: Gas/Bitumen Production in Oil Sands Areas*, March 1998
GCMS	gas chromatography-mass spectrometry
GOB decision	*AEUB 2005-122: Phase 3 Final Proceeding Under Bitumen Conservation Requirements in the Athabasca Wabiskaw-McMurray*
ISH	ISH Energy Ltd.
KN06 decision	*2021 ABAER 001: Canadian Natural Resources Limited, Regulatory Appeal of Amendment Approval 11475 EE, Kirby North*
kPa	kilopascal
m	metre
m^3	cubic metre
MOP	maximum operating pressure
OSCA	*Oil Sands Conservation Act*
REDA	*Responsible Energy Development Act*
PAH	polycyclic aromatic hydrocarbons
RGS	EUB-initiated regional geological study of the Athabasca area of the Wabiskaw-McMurray deposit
SAGD	steam-assisted gravity drainage
Vshale	volume of shale

2024 ABAER 004

Canadian Natural Resources Limited
Application to Amend Commercial Scheme Approval No. 11475 for Pads KN08 and KN09 at Kirby North In Situ Oil Sands Development

Application No. 1936092

Decision

[1] Having carefully considered all the evidence, the Alberta Energy Regulator (AER) approves application 1936092 (Application) as being in the public interest subject to the conditions in appendix 2.

[2] In reaching this decision, we, the AER hearing panel presiding over this proceeding, considered all relevant materials properly before us, including each party's evidence and arguments. Where we referred to specific portions of the evidence, we intended to assist the reader in understanding our reasoning on a particular matter and do not mean that we did not consider all relevant portions of the evidence.

Introduction

Application

[3] On March 11, 2022, Canadian Natural Resources Limited (Canadian Natural) applied to the AER under section 13(1) of the *Oil Sands Conservation Act* (*OSCA*) and *Draft Directive 023: Oil Sands Project Applications* (*Directive 023*) to amend commercial scheme approval No. 11475, which allows for the recovery of crude bitumen from the McMurray-Wabiskaw deposit. The amendment is to add two steam-assisted gravity drainage (SAGD) drainage boxes: KN08 and KN09, which are in Sections 2 and 3, Township 75, Range 9, West of the 4th Meridian and Sections 33 and 34, Township 74, Range 9, West of the 4th Meridian. The new SAGD well pairs for these drainage boxes will be drilled from surface locations in Sections 1 and 2, Township 75, Range 9, West of the 4th Meridian.

[4] Figure 1 is a map showing the proposed KN08 and KN09 drainage boxes, the approved KN01 through KN07 drainage boxes, the Kirby North development area, the Kirby project area, the proposed Kirby project area expansion, and the proposed Kirby North development area expansion.

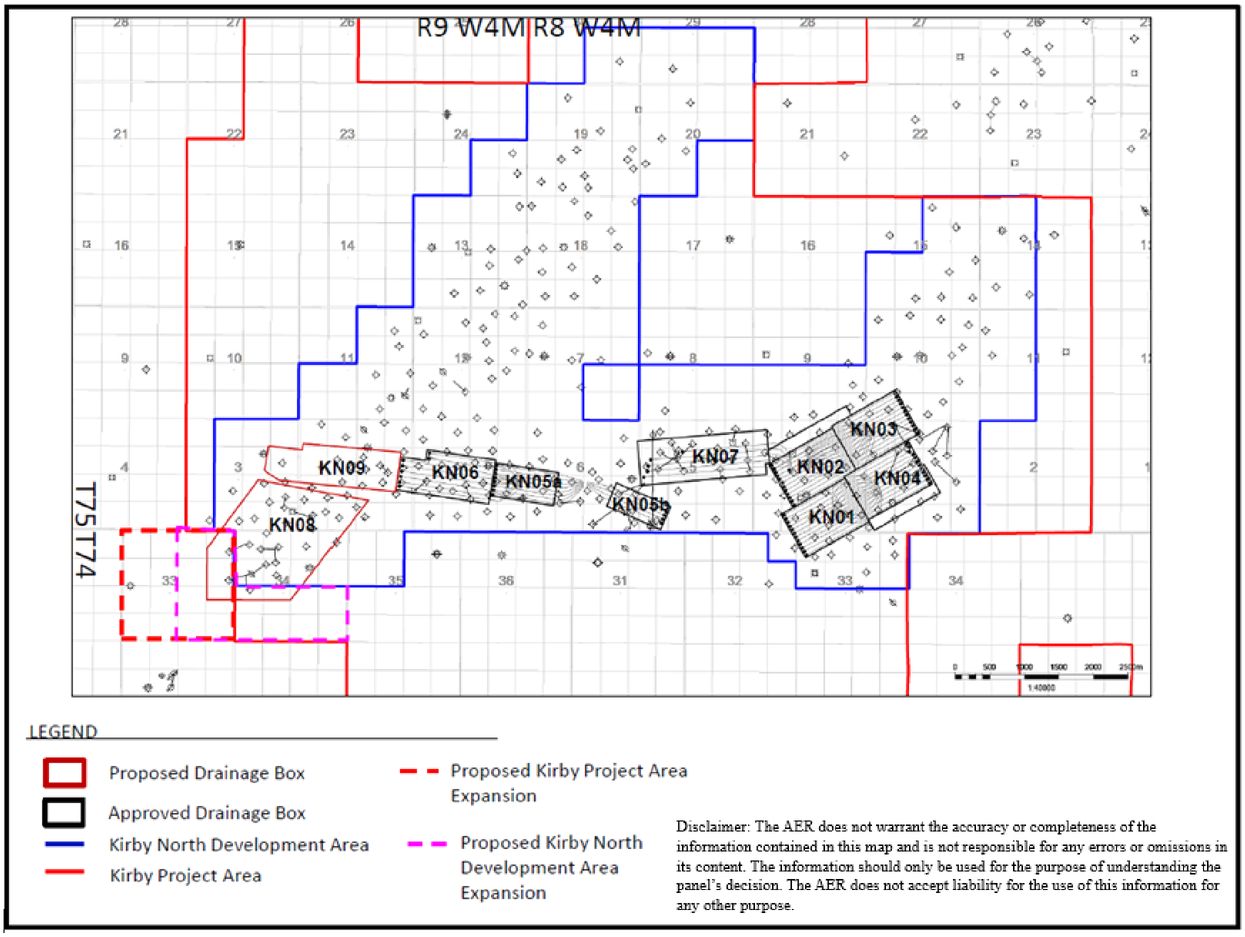


Figure 1. Proposed drainage boxes KN08 and KN09 (red) and approved drainage boxes KN01 to KN07 (black) (Source: Canadian Natural's application 1936092)

[5] The Application is to amend commercial scheme approval No. 11475 for the Kirby North in situ oil sands project development for the recovery of crude bitumen from the McMurray Formation and does not include the Wabiskaw D bitumen zone.

[6] ISH Energy Ltd. (ISH) holds petroleum and natural gas rights overlying but not including oil sands in the Kirby North project area. On April 8, 2022, ISH filed a statement of concern on the Application.

Background

[7] On May 1, 2023, the AER determined that the Application should be set down for a hearing.

[8] On June 14, 2023, the AER issued a notice of hearing for proceeding 430. The notice stated that the AER would hold a hearing to consider the Application. ISH applied to participate in the hearing on July 6, 2023, and was granted participation rights on August 2, 2023.

[9] The AER held a public hearing in Calgary, Alberta, which started on February 6, 2024, and ended on February 9, 2024, before hearing commissioners C.L.F. Chiasson (presiding), B.A. Zaitlin, and M.A. Barker. The hearing participants are listed in appendix 1.

Legislative Framework

[10] The AER's mandate under the *Responsible Energy Development Act* (*REDA*) includes providing for the efficient, safe, orderly, and environmentally responsible development of energy resources and mineral resources in Alberta.

[11] Under section 30 of *REDA*, an application under an energy resource enactment must be made to the AER. *OSCA* is listed as an energy resource enactment in section 1(1)(j)(iv) of *REDA*.

[12] Canadian Natural submitted the Application under section 13 of *OSCA*, which provides for amendment of approvals granted under section 10 of *OSCA*. Section 10(1)(b) requires an approval for the commencement or continuation of a scheme for crude bitumen recovery. Under section 10(3), the AER may grant an approval on any terms and conditions it considers appropriate if it is of the opinion that the approval is in the public interest. Alternatively, the AER may refuse to grant an approval, defer consideration of the approval application, or make any other disposition of the application it considers appropriate.

[13] *Directive 023* establishes requirements for oil sands project applications, including amendment applications. Canadian Natural submitted the Application as a category 3 amendment, as required under section 9 of *Directive 023*.

[14] The hearing commissioners constituting this hearing panel are empowered under section 12(1)(a) of *REDA* to carry out hearings of applications and make decisions in the name of and on behalf of the AER. Pursuant to section 35 of *REDA*, we must decide whether to grant Canadian Natural's Application and what, if any, approval terms and conditions should be included.

[15] As set out in section 15 of *REDA* and section 3 of the *Responsible Energy Development Act General Regulation*, in considering an application in respect of an energy resource activity under an energy resource enactment, we must consider (a) the social and economic effects of the energy resource activity, (b) the effects of the energy resource activity on the environment, and (c) the impacts on a landowner as result of the use of the land on which the energy resource activity is or will be located. In addition to these factors, section 15 of *REDA* requires us to consider the interests of landowners.

Proceeding Context

[16] The Application proposes to add the KN08 and KN09 drainage boxes to recover crude bitumen in the McMurray Formation as part of Canadian Natural's Kirby North project for in situ oil sands development. The Application focused on the location, geology, and planned operation of the drainage

boxes. Matters such as processing, steam generation, and water use are covered within the existing Kirby North approval and were not included in the Application. Any environmental outcomes from this Application were expected to be consistent with those covered by prior environmental impact assessments of the Kirby in situ project and expansion. As such, the Application did not include a discussion of environmental matters.

[17] ISH has a joint interest with Canadian Natural in the gas in the Kirby Upper Mannville II gas pool (within the Wabiskaw B Formation) overlying the drainage boxes. ISH has 46.25% interest and Canadian Natural has 53.75% interest in the gas. Gas production from the Kirby Upper Mannville II gas pool has been shut in since 2004 pursuant to decisions made by the Alberta Energy and Utilities Board (EUB; the predecessor to the AER).

[18] In the mid-1990s, the EUB began an extensive review and consideration of the relationship between gas and bitumen production in Alberta's oil sands regions. Industry raised concerns that production of natural gas directly above and in pressure communication with bitumen deposits (i.e., associated gas) would adversely affect bitumen production through pressure depletion. Following an inquiry and a regional geological study of the Athabasca Wabiskaw-McMurray region (*EUB Report 2003-A, Athabasca Wabiskaw-McMurray Regional Geological Study* [RGS]), the EUB concluded that producing gas that is associated with potentially recoverable bitumen, and thereby reducing the reservoir pressure, presents an unacceptable risk to SAGD bitumen recovery. As such, in its decision (*EUB Decision 2005-122: Phase 3 Final Proceeding Under Bitumen Conservation Requirements in the Athabasca Wabiskaw-McMurray* [GOB [gas over bitumen] decision]), the EUB ordered gas production from various associated gas pools shut in, including the Kirby Upper Mannville II pool.

[19] In a 1998 EUB inquiry into gas and bitumen production in oil sands areas, the EUB discussed the possibility that aquathermolysis could produce hydrogen sulphide and carbon dioxide during thermal bitumen production that might migrate into and contaminate overlying associated gas. The EUB indicated that, in those circumstances, it believed cleaning the gas would be feasible, albeit at an additional cost, and would be in the public interest compared with trying to mitigate the effect of associated gas production on thermal bitumen recovery.

[20] The AER dealt with a matter similar to this proceeding in *2021 ABAER 001: Canadian Natural Resources Limited, Regulatory Appeal of Amendment Approval 11475 EE, Kirby North* (KN06 decision). The KN06 decision was on ISH's regulatory appeal of an approval amendment adding SAGD drainage box KN06 to Canadian Natural's Kirby North scheme. The KN06 decision briefly discussed the EUB 1998 inquiry and GOB decision related to economic considerations. The AER found that potential adverse effects to ISH from that approval amendment were commercial and monetary in nature. In that decision, the AER also held that unnecessary harm to energy resources is inconsistent with the AER's mandate to ensure efficient, safe, and orderly development and that meeting the AER's mandate means

ensuring a balance between costs and benefits of mitigation measures rather than protecting ISH's interest in the Kirby Upper Mannville II gas pool no matter the cost.

[21] Aside from ISH, there were no other statements of concern or participation requests filed in this proceeding. No concerns were raised about the social or environmental effects of the Application, nor impacts on landowners. ISH's focus was on the potential effects on its interest in the Kirby Upper Mannville II pool from the SAGD operations proposed in the Application.

[22] ISH indicated that it sought an outcome that would allow Canadian Natural to develop the bitumen resource without unreasonable and adverse effects on ISH's gas production. ISH advocated that if we grant the Application, we should also include conditions in the approval to protect its interests. Canadian Natural acknowledged that hydrogen sulphide contamination of the Kirby Upper Mannville II pool is a potential consequence of steam from the McMurray reservoir reaching the pool during the producing life of the drainage boxes. However, Canadian Natural argued that the technical evidence indicates this is a very low risk and that its proposed mitigation measures are reasonable considering related benefits and costs.

[23] In this proceeding, we must decide whether the Application is in the public interest. We must determine if the Application is sound in relation to the technical and regulatory requirements, and we must consider if conditions or mitigation measures are required for the appropriate conservation of the Kirby Upper Mannville II gas.

[24] Although we are not bound by the KN06 decision, we agree with the finding made by that panel that unnecessary harm to energy resources is inconsistent with the AER's mandate to ensure efficient, safe, and orderly development. In this proceeding, this means ensuring a balance between the costs and benefits of the mitigation measures.

[25] A key issue for this hearing involved determining whether effective confinement strata overlie the McMurray bitumen reservoir to contain the SAGD steam chambers at KN08 and KN09 over the life of the drainage boxes. We understand ISH's primary concern to be ensuring that no steam or reaction products from SAGD operations migrate upwards to contaminate the Kirby Upper Mannville II gas pool.

[26] To determine if the McMurray steam chambers can be contained and isolated from the Kirby Upper Mannville II pool, we focused on the following questions, which we interpreted from the evidence and arguments exchanged at the hearing:

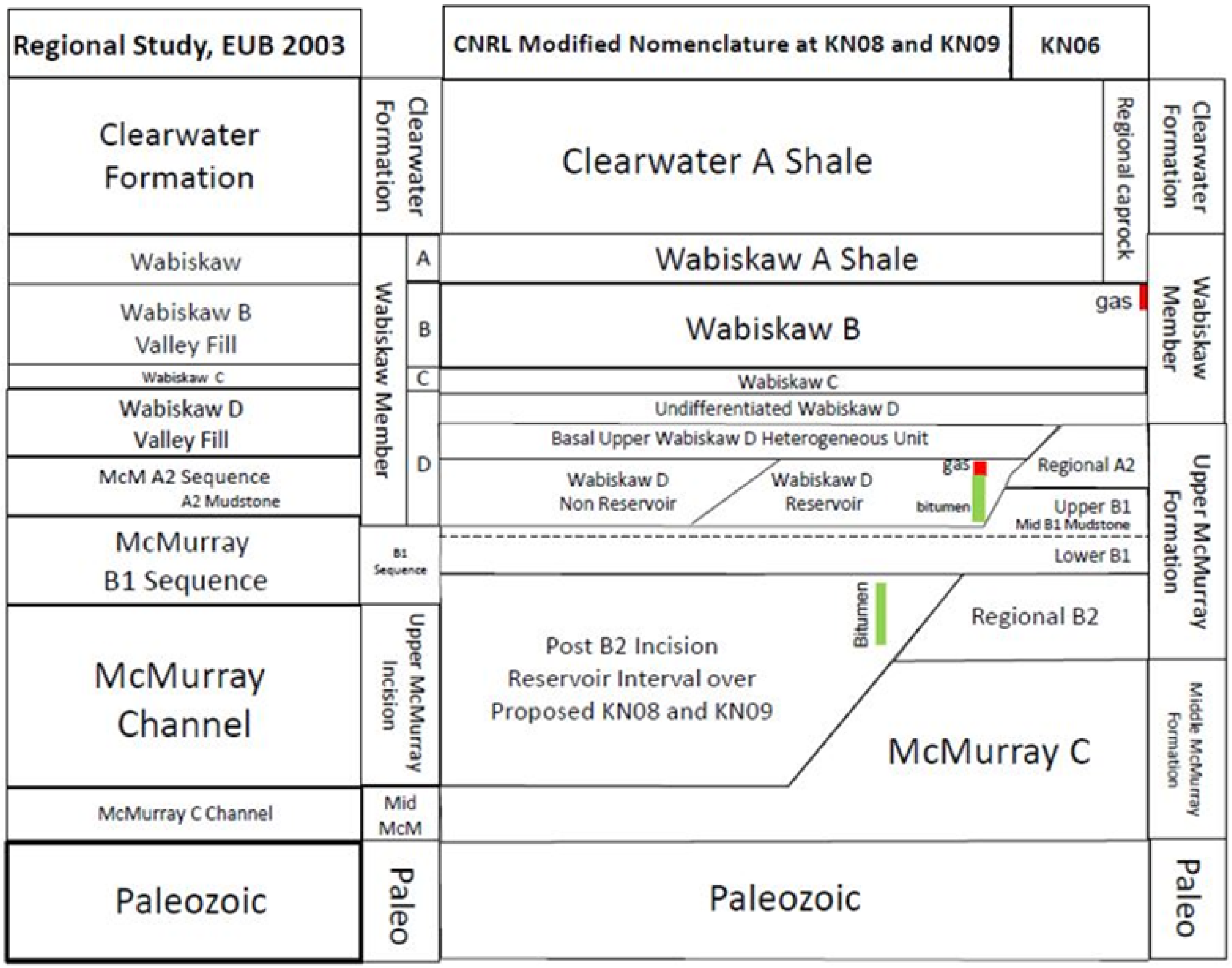
- What are the geological characteristics of the potential confinement strata? Is there a single barrier or an aggregation of strata that could contain the McMurray steam chamber? What is the spatial extent of the geological barriers and baffles that could isolate the steam chamber from the Kirby Upper Mannville II gas pool?

- Are there any existing faults, fractures, or other breaches in the barriers that would result in communication between the bitumen reservoir and the Kirby Upper Mannville II gas pool?
- Could initial start-up or long-term operations of the drainage boxes induce fractures that would result in communication between the McMurray steam chamber and the Kirby Upper Mannville II gas pool?

KN08 and KN09 Geology: Stratigraphic Framework

[27] The stratigraphy is known to vary across the greater Kirby area. Both Canadian Natural and ISH acknowledged that the geology in the KN08 and KN09 areas differs from that of the previously approved KN06 area and that the stratigraphic framework shown in Figure 2 identifies the nomenclature of the sequence of strata relevant to this proceeding.

[28] Figure 2 compares the stratigraphy for the Kirby area (as developed in the RGS) with that of the KN08 and KN09 area, Application, and the stratigraphy used in the KN06 decision. The stratigraphy is shown to differ regionally between the RGS, KN06, and KN08/KN09 areas.



Disclaimer: The AER does not warrant the accuracy or completeness of the information contained in this framework and is not responsible for any errors or omissions in its content. The information should only be used for the purpose of understanding the panel's decision. The AER does not accept liability for the use of this information for any other purpose.

Figure 2. Modified stratigraphic framework for the Kirby area (Source: Canadian Natural's application 1936092)

[29] In figure 2, the main reservoir units are highlighted by the green (bitumen) and red (gas) vertical bars in the KN08-KN09 stratigraphic column. The bitumen reservoir pertaining to the Application is associated with the post-B2 valley incision. The Kirby Upper Mannville II gas pool is associated with the Wabiskaw B Formation.

[30] Canadian Natural interpreted two major episodes of incised valley erosion across the KN08-KN09 area: the post-B2 incision that eroded portions of the regional McMurray B2 sequence and the Wabiskaw D incised valley that eroded portions of the regional McMurray B2 sequence, mid-B1 Mudstone, and A2 mudstone. Due to the two episodes of erosion, only some of the confinement strata may be present at any one location across the KN08 and KN09 drainage boxes.

Containment of SAGD Steam: Confinement Strata, Barriers, and Baffles

[31] Canadian Natural used the following definitions for barriers and baffles. Barriers are impermeable to steam over the life of the SAGD operations, whereas baffles may interfere with and impede the movement of steam but do not stop it entirely. We note that ISH did not refute these definitions. We accept these descriptions as definitions of barriers and baffles, and we further note that the parties agreed to the concept of the operational life of a SAGD drainage box being in the order of 20 years or more.

[32] We also note that the RGS accepted that a mudstone that could be correlated regionally, or a shale that was greater than 0.5 m in thickness and could also be correlated regionally, would act as a potential barrier to vertical hydraulic communication.

[33] Barriers may consist of a single zone, a unit or a series of zones, or units or aggregations of strata that are impermeable to steam over the operational life of the drainage box.

[34] Areas with strata having higher proportions of shale or mudstone are assumed to have barrier or baffle characteristics.

[35] Canadian Natural contended that extensive operational experience since the GOB decision shows that steam is often effectively contained by heterolithic strata. These aggregations of strata contain numerous barriers and baffles that work together to ensure steam chamber containment over the life of the operations.

[36] Canadian Natural proposed there are six low vertical permeability units with an aggregate thickness of 3.9 to 14.3 m over the drainage boxes.

[37] Canadian Natural contended that the characteristics of effective confinement strata include a high volume of shale (Vshale >50%), low vertical permeability, and strata that are geomechanically competent.

Confinement Strata

[38] The strata proposed by Canadian Natural to contain the steam chambers at KN08 and KN09 consist of an aggregate of (Figure 2, stratigraphically from top to bottom):

- Wabiskaw C (Top)
- Wabiskaw D heterolithic unit (also referred to as the Wabiskaw D heterogeneous unit)
- Wabiskaw D non-reservoir
- A2 mudstone
- mid-B1 mudstone

- McMurray post-B2 non-reservoir (Base)

[39] In this proceeding, Canadian Natural and ISH disagreed about the continuity, lateral extent, and sealing capacity of specific stratigraphic units. ISH contended that strata between the McMurray bitumen reservoir and Kirby Upper Mannville II gas pool do not effectively form a barrier to vertical steam migration due to factors such as the lateral discontinuity of the A2 mudstone and the mid-B1 mudstone, the presence of naturally occurring fracture networks, and the potential for induced fracturing breaching otherwise effective barriers as a result of SAGD operations.

[40] Consequently, the primary arguments in this proceeding involved the degree to which these stratigraphic units will confine and prevent the upward migration of steam from SAGD production of bitumen in the Upper McMurray Formation from reaching and potentially contaminating the Kirby Upper Mannville II gas pool in the Wabiskaw B unit.

[41] It should be noted, however, that in the KN08 and KN09 area, the AER, Canadian Natural, and ISH accept the Clearwater shale combined with the Wabiskaw A shale unit as being the impervious caprock preventing steam associated with SAGD production in the McMurray Formation from migrating upward into the overlying Grand Rapids (or shallower) formations. Neither party disputed the effectiveness of the regional caprock.

[42] The factors for determining whether a unit would be an effective barrier to steam migration include the thickness of the confining strata, the volume of shale (Vshale) or mudstone contained within each rock unit, the degree of heterogeneity of the sediments, and the lateral continuity of the units. The Vshale of a unit is important because the higher the Vshale percentage, the more likely the unit could be deemed a potential barrier. These factors are discussed for the proposed confinement strata in the following sections.

Wabiskaw C Unit

[43] Canadian Natural explained the Wabiskaw C unit is the topmost interval of the confinement strata (Figure 2) and described it as muddy sandstone bioturbated to the point that very few primary sedimentary structures were preserved.

[44] Canadian Natural estimated that the Vshale is about 70%, whereas ISH believed the Vshale for Wabiskaw C shale strata was approximately 35% and, at best, the strata should be defined as a baffle.

[45] ISH argued that the bioturbation in the Wabiskaw C can cause vertical permeability pathways, and individual mudstones associated with the Wabiskaw C had limited lateral extent and, therefore, lacked the continuity of a barrier.

[46] ISH and Canadian Natural had significantly different estimates of the range of Vshale values, the range of shale thickness, how the shales are correlated between wells, and the stratigraphic definition of

the Wabiskaw C. The differences regarding shale estimates made it difficult for us to determine the effectiveness of the Wabiskaw C strata as a potential barrier or baffle.

[47] However, we note that Canadian Natural contended that based on gas pool mapping, the Wabiskaw C unit acts as an effective top seal for gas at the top of the Wabiskaw D unit. Canadian Natural showed the Wabiskaw D gas cap mapped over the northeast corner of the KN08 drainage box and the eastern third of the KN09 drainage box, demonstrating the sealing capacity of the Wabiskaw C.

[48] We further note Canadian Natural presented gas chromatography-mass spectrometry (GCMS) data that indicates the Wabiskaw C is separated from the Wabiskaw D, which supports the existence of a barrier.

[49] Based on this evidence, we are of the opinion that the Wabiskaw C has the potential to act as a barrier to vertical fluid movement.

Wabiskaw D Unit

[50] Canadian Natural presented an isopach map of the Wabiskaw D heterolithic unit and noted that it occurs in the same region where the A1 mudstone has been removed. The Wabiskaw D heterolithic unit covers the central portion of KN09 and the northern third of the KN08 drainage box with up to 3 m of mudstone. Canadian Natural suggested that its high Vshale of over 50% suggests it would be expected to be a barrier to the vertical rise of steam.

[51] Canadian Natural estimated the Wabiskaw D non-reservoir unit varies from 0.5 to 3.8 m and is mapped to cover all but the very northeast corner of the KN08 drainage box. At KN09, the unit covers the western two-thirds of the drainage box. It is estimated to have a Vshale of about 60%, and the unit consists of centimetre- to decimetre-scale dark, very lightly bioturbated wavy mud beds.

[52] On the other hand, ISH contended the Wabiskaw D strata are mostly sand, and the sediments are heavily bioturbated, enhancing vertical permeability. Further, the muddy sandstones are not continuous and do not provide a barrier on a regional basis. In ISH’s opinion, the Wabiskaw D strata is thin and risks communication between the McMurray and Wabiskaw Formations.

[53] Canadian Natural presented structural mapping demonstrating that the Wabiskaw D unit contains two distinct gas caps. A lower gas cap is present in a thin basal Wabiskaw D sandstone overlain by the Wabiskaw D heterolithic unit. A separate gas cap occurs where the unit is very sandstone rich at the top of the Wabiskaw D and is trapped by the Wabiskaw C.

[54] Canadian Natural also contended that the GCMS results indicated a barrier at the base of the Wabiskaw D in all the wells analyzed.

[55] Based on Canadian Natural's mapping and GCMS results, we find that the presence of two gas caps is compelling and accept that it confirms the presence of localized seals within the Wabiskaw D unit. In our view, the compartmentalization of gas zones within the combined Wabiskaw D unit confirms the presence of multiple stacked barriers.

[56] This suggests to us that, even if units with higher shale content may be discontinuous over the entire area of the drainage boxes, their combined presence may form a barrier to the underlying steam chambers in the bitumen-bearing McMurray Formation.

Upper McMurray Formation – Regional A2 Mudstone

[57] Canadian Natural submitted that the A2 mudstone has been identified as a barrier to steam in the GOB decision and the previous KN06 decision.

[58] Both Canadian Natural and ISH agreed that the Wabiskaw D-aged erosional event removed areas of the A2 mudstone in the KN08 and KN09 areas but disagreed on the lateral extent of the remaining A2 mudstone. Canadian Natural mapped the A2 mudstone over the southern two-thirds of the KN08 drainage box and the eastern end of the KN09 drainage box, whereas ISH contended that the A2 mudstone is absent over most of the KN08 and KN09 areas.

[59] Canadian Natural submitted that other confinement strata exist to assist in providing steam containment where the A2 mudstone was removed.

[60] The A2 mudstone was interpreted by Canadian Natural to act as a top seal to trap a small gas cap in the upper B1 sequence in one well and contended that in a second well, GCMS confirmed the presence of a barrier across the A2 mudstone.

[61] We note that both parties provided mapping of the lateral extent of the A2 mudstone in the KN08 and KN09 areas. We are of the view that Canadian Natural's mapping was more convincing as its process was much more rigorous, used more data, and was more comprehensive than ISH's mapping. Therefore, we are of the view that Canadian Natural's mapping more closely represents the extent of the A2 mudstone in the vicinity of the KN08 and KN09 drainage boxes.

Upper McMurray Formation: Mid-B1 Mudstone

[62] Canadian Natural stated that the regional B1 sequence of the Upper McMurray Formation consists of variably heterolithic bioturbated sandstones and mudstones.

[63] While overlying Wabiskaw D erosion has locally removed the upper portions of the regional B1 sequence, the mid-B1 mudstone was interpreted by Canadian Natural to be present over the entirety of both drainage boxes. Canadian Natural claimed the mid-B1 mudstone ranges in thicknesses from approximately 0.1 to 0.8 m and is easily correlated in logs and supported by an abundance of core.

[64] ISH strongly disagreed with Canadian Natural's interpretation of the continuity of the mid-B1 mudstone, and both parties' isopach mapping of the mid-B1 mudstone was significantly different. We were presented with various core photos and wireline logs that were at the limit of resolution to determine the presence or absence of the mid-B1 mudstone, and it was difficult for us to interpret if the mid-B1 mudstone was present as a correlatable unit across the two drainage boxes.

[65] Canadian Natural contended that GCMS analyses indicated the regional B1 sequence contains baffles and barriers that would be expected to provide steam containment over the KN08 and KN09 drainage boxes. Canadian Natural characterized the mid-B1 mudstone as a barrier in both of the KN08 area wells sampled for GCMS; however, ISH pointed out that there was no data from the mid-B1 mudstone from a well within the proposed KN09 drainage box. Canadian Natural was of the view that although the Wabiskaw D incision resulted in the localized removal of the mid-B1 mudstone, other baffles and a strong barrier were present that would contain steam.

[66] We find both parties' evidence about the lateral continuity of the mid-B1 mudstone inconclusive, and we make no determination about the presence or absence of the mid-B1 mudstone in the KN08 and KN09 areas.

Upper McMurray Formation – Post-B2 Reservoir and Non-Reservoir Facies

[67] Canadian Natural explained that the McMurray post-B2 bitumen reservoir occurs within a fluvial-estuarine incised valley system and is overlain by shallow marine deposits punctuated by multiple marine flooding surfaces and parasequences. In the McMurray Formation, tidally influenced meandering estuarine point bar channel deposits comprise the reservoir.

[68] Canadian Natural described the post-B2 non-reservoir facies as consisting of mudstone-prone inclined heterolithic stratification, consisting of interbedded sand and silt strata deposited as part of tidally influenced point bars, which comprise localized barriers to vertical steam chamber growth at multiple horizons within the reservoir. Canadian Natural estimated these individual mudstone beds are centimetres to decimetres thick with Vshale greater than 50%. ISH contended that the muddy sandstones are not continuous and do not provide a barrier on a regional basis.

Additional Factors Considered

[69] Canadian Natural emphasized that stratigraphic context is very important in assessing a unit's ability to provide steam containment. We agree that the overall geological context is very important, and thus, we considered several factors presented by the parties that contribute to determining whether the strata overlying the SAGD steam chambers at KN08 and KN09 will provide effective steam containment. In addition to the geological analyses of the confining strata discussed above, we considered the following additional factors, listed in order of decreasing importance, when making our decision:

- pressure data
- operational evidence
- GCMS data
- core and borehole image logs
- 3D seismic
- theoretical modelling, including hydrocarbon sourcing, differential compaction, and steam chamber migration rates through various depositional facies

Pressure Data

[70] Canadian Natural explained that it conducts pressure monitoring to assess connectivity between reservoirs and that a preproduction pressure difference is definitive evidence of a barrier or a lack of communication between zones.

[71] Canadian Natural presented pressure data from the Kirby Upper Mannville II pool and within the McMurray bottom water leg. They explained that a pressure differential would not be expected if faults or an open, connected fracture system were present between the two zones at KN08 and KN09. Canadian Natural stated that there is a significant pressure differential, confirming these zones are not in communication with each other and contended that this is compelling evidence that faults or open, connected fractures between the McMurray and Kirby Upper Mannville II pool at KN08 and KN09 do not exist, or, in the unlikely case that they do exist and remain undetected, they are closed to fluid flow.

Operational Data

[72] Canadian Natural stated that lost circulation events during drilling operations can be a direct indicator of faults or open fractures and that it has not experienced any lost circulation events during the drilling of 43 stratigraphic test wells in the KN08 and KN09 areas or in drilling 16 producer and injector wellbores at the offsetting KN06 drainage box.

[73] We find the drilling operations results of no lost circulation events and the pressure monitoring data in the KN08 and KN09 areas compelling evidence that no faults or open fractures exist at these drainage boxes that would result in loss of steam or fluids.

Gas Chromatography-Mass Spectrometry

[74] GCMS is an analytical technique to identify the chemical compounds in a given sample. In this proceeding, GCMS was used to analyze the polycyclic aromatic hydrocarbon (PAH) components of bitumen extracted from the drill core to assess the potential sealing capacity of confinement strata by

indicating layers across which hydrocarbon concentration profiles change markedly. [Fustic et al. 2011[1] and 2013[2])]

[75] Plotting the biodegradation-susceptible PAH concentrations in samples from the hydrocarbon-bearing intervals in a well can show where a barrier likely exists between vertically stacked layers at that well location. Hydrocarbons isolated within the same geologic compartment will have similar concentration values. Where the data exhibit generally continuous hydrocarbon concentration values from one reservoir or interval to the next, connectivity exists between those units. Clear and sharp concentration changes at a specific depth indicate a barrier. Canadian Natural submitted that when GCMS results are closely tied to confinement strata stratigraphy, GCMS is an important tool in predicting the possibility of vertical steam rise within the reservoir and overlying confinement strata.

[76] Canadian Natural further contended that if oil concentrations had not equilibrated across low-permeability beds or heterolithic units over geological time, it is very unlikely that steam could migrate through these lower-permeability zones over the life of a SAGD drainage box. Therefore, this indicates the presence of a barrier.

[77] Canadian Natural plotted GCMS results for six wells that exhibited characteristic gradient variations across specific zones, layers, or strata that it interpreted as barriers or baffles. Canadian Natural contended that all sampled wells showed one or more likely barriers to fluid migration within the confinement strata.

[78] ISH proposed that since different intervals act as barriers in different wells, this suggested that the individual barriers were not laterally continuous over the entire area of the proposed development. ISH suggested that there are possible gaps between the different barriers and baffles that would enable steam reaction products to migrate into shallower stratigraphic zones.

[79] ISH did not dispute the usefulness of GCMS data or that it can be used to identify separate geologic compartments but challenged the way Canadian Natural interpreted the GCMS data and the limited data provided by Canadian Natural to support its interpretation.

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[1] Fustic, M., B. Bennet, J. J. Adams, H. Huang, B. MacFarlane, D. Leckie, and S. R. Larter, 2011, Bitumen geochemistry: A tool for distinguishing barriers from baffles in oil sands reservoirs: Bulletin of Canadian Petroleum Geology, v. 59, p. 295–316

[2] Fustic, M., Bennet, B., Hubbard, S.M., Huang, H., Oldenburg, T. and Larter, S. (2103). Impact of Reservoir Heterogenity and GeoHistory on the Variability of Bitumen Properties and on the Distribution of Gas and Water-saturated Zones in the Athabasca Oil Sands, Canada. In F.J. Hein et al (eds.) Heavy oil and oil sand petroleum systems in Alberta and beyond. AAPG Studies in Geology 64, p.163-205

[80] We note that both parties observed reservoir compartmentalization and at least one strong barrier in each of the six wells for which GCMS data was provided; there appeared to be concurrence between the parties that the lateral extent of a barrier cannot be predicted based on GCMS analysis alone.

[81] Based on the information from Fustic et al., 2011 and 2013 and evidence from Canadian Natural's and ISH's witnesses, we accept that GCMS analysis is a viable technique to identify potential barriers and baffles. However, we also concur with Canadian Natural's opinion that GCMS is a one-dimensional vertical analytical technique and determining the presence and lateral extent of barriers or baffles requires stratigraphic correlation using tools such as core, well log and seismic data.

[82] We accept Canadian Natural's correlation of the GCMS results with core and well data and its interpretation of the presence and location of barriers.

[83] We also accept Canadian Natural's conclusion that it is more likely than not that the barriers that impeded the uniform biodegradation of hydrocarbon components over geologic time will also prevent the passage of steam over the operational life of the drainage boxes.

[84] Therefore, we find that GCMS data, when used with other tools and corroborating information, supports the presence of localized barriers between the McMurray reservoir and the Kirby Upper Mannville II gas pool at the KN08 and KN09 drainage boxes.

Core and Borehole Image Logs

[85] Canadian Natural and ISH had significantly different interpretations about whether natural or drilling-induced fractures were present in cores and borehole image data. ISH interpreted cracks observed in the drill core to be open and naturally occurring fractures, whereas Canadian Natural contended that they were induced by drilling.

[86] ISH purchased borehole image logs in the Kirby North area from a third-party vendor and provided a map of where ISH interpreted naturally occurring fractures to be present. Canadian Natural tabulated all of ISH's interpreted fractures from both the core and the borehole image logs against the accepted stratigraphy. Canadian Natural contended that only one well from those image logs where ISH identified a fracture was over the drainage boxes. Canadian Natural further contended this feature was a tool mark instead of a fracture and was within the caprock interval above the Wabiskaw B gas zone and not within any of the confinement strata.

[87] We note that no evidence was presented regarding the connectivity of fractures or the presence of fracture networks in the confinement strata.

[88] In our view, uncertainty remains in confirming the presence of natural fractures based on core and borehole image logs. As such, we are of the opinion that core and borehole imaging is a tool best used in conjunction with other information to ascertain the effectiveness of proposed confinement strata.

3D Seismic

[89] Canadian Natural indicated that the entire area was covered by 3D seismic and submitted various seismic maps designed to highlight areas of lateral discontinuity and stratigraphic variations but showed little to no structural discontinuities. ISH used the same maps and interpreted indications of potential faults and structural discontinuities.

[90] Canadian Natural contended that its 3D seismic structure and attribute mapping showed no evidence of faulting within the confinement strata. It indicated that structural sags exist from a minor amount of differential compaction over mud-filled abandonment channels at KN08 and KN09. This compaction caused some minor folding in the overlying sediments; however, faults from this differential compaction were neither expected nor observed on Canadian Natural's 3D seismic mapping.

[91] ISH proposed a different interpretation and contended there were many deep-seated faults and fault networks associated with compression and that differential compaction developed a fracture network breaching the containment strata and allowing for potential communication between the McMurray reservoir steam chamber and the Kirby Upper Mannville II gas pool.

[92] We note the thorough and detailed explanation Canadian Natural provided regarding the correlation of seismic data with its stratigraphic and geologic data. Based on that, we accept Canadian Natural’s evidence that the seismic images show little to no evidence of large-scale faulting or fracturing across KN08 and KN09 and do show stratigraphic heterogeneities, including some effects of differential compaction.

[93] We further note, however, that the scale of the resolution of seismic imaging made it impossible to detect small-scale or localized fracturing, and, as such, we are of the view that seismic imaging on its own is inconclusive and is a tool to be used with other data and techniques to determine the presence of small-scale faults, fractures, and other existing breaches within the confinement strata.

Differential Compaction Model

[94] ISH contended that differential compaction has resulted in faults and fractures of the overlying confinement strata.

[95] Canadian Natural suggested that differential compaction at KN08 and KN09 was mostly related to areas of the post-B2 incision edges and where mud-filled abandonment channel plugs (abandonment plugs) exist within the incision. Canadian Natural estimated that the resulting compaction observed over these small abandonment plugs at KN08 and KN09 was in the order of 3 to 5 m at the Wabiskaw B level, which it considered minor. Canadian Natural explained that faults or fractures are not expected to be present from this small amount of sag, which it contended was confirmed by a review of its seismic, core data, and borehole image logs. Canadian Natural further contended that its evidence does not support ISH’s differential compaction theory.

[96] Based on the discussion above, we are of the opinion that differential compaction is not significant in the KN08 and KN09 areas, as few, if any, existing fractures have been confirmed between the McMurray Reservoir and the Kirby Upper Mannville II gas pool.

Hydrocarbon Sourcing Model

[97] In support of its position that faults and fractures exist that would allow steam migration from the McMurray to the Wabiskaw B, ISH proposed that the gas within the Kirby Upper Mannville II pool resulted from the degradation of McMurray-sourced oil by migrating vertically through a preexisting network of open fractures and faults.

[98] Canadian Natural disagreed with this model. It suggested an alternative theory for the occurrence of Wabiskaw B gas in the KN08 and KN09 area: that Wabiskaw B gas is self-sourced from the degradation of Wabiskaw B oil and that the gas generated from the degraded McMurray oil likely migrated over geologic time laterally, away from the area updip along the post-B2 incision valley trend.

[99] In our view, neither party showed convincing evidence to support their respective positions on Wabiskaw B gas generation. As discussed in the preceding sections, we are of the view that the evidence presented indicates an absence of existing faults and open fractures in the confining strata regardless of the sourcing model.

Confinement Strata Summary

[100] Based on our review and findings in the above sections, we find there is no persuasive evidence of existing faults or open fracture networks that would create transmissible fluid pathways through confinement strata overlying the KN08 and KN09 steam chambers.

[101] We accept that confinement strata can include an aggregate of barriers and baffles and that a combination of baffles and barriers could effectively isolate steam chambers from overlying gas pools over the operational life of the drainage boxes. In our view, one does not need to ensure the presence of each laterally continuous mudstone layer to fully contain steam chambers. Rather, we agree with the KN06 decision, where the panel found that a combined package of more than one mud-prone unit, where present, should effectively confine the movement of steam.

[102] Therefore, we are of the opinion that the six confinement strata proposed by Canadian Natural are more likely than not to provide effective containment of SAGD operations at the KN08 and KN09 drainage boxes and will serve to isolate those operations from impacting the Kirby Upper Mannville II gas pool.

[103] We note that the interpretation of barriers to vertical fluid migration and the understanding of what constitutes effective containment of steam from McMurray SAGD operations has evolved over several proceedings:

- The RGS (2003) interpreted two regional mudstone barriers.
- The KN06 decision (2021) interpreted a combined package of three mudstone barriers for the KN06 area.
- In this proceeding, we found that a combination or aggregate of six mud-prone strata is likely to provide containment for the KN08 and KN09 areas.

[104] In summary, in reviewing the geological evidence and all the assessed parameters outlined above, we are convinced that the confinement strata in the KN08 and KN09 areas will be an effective barrier to steam.

Maximum Operating Pressure and the Potential for Induced Fracturing

[105] The AER regulates the maximum operating pressure (MOP) of SAGD operations through *Directive 023* and *OSCA*. MOP is related to the potential risk of induced shear or tensile failure of the surrounding geology during SAGD operations. In our view, determining the MOP in this case involves discussing the potential for induced fracturing of the confinement strata during two operational stages:

- start-up-induced fracturing during the initial stages of SAGD operations
- impacts of long-term SAGD operations on the integrity of the confinement strata

[106] Looking broadly, we are of the view that three distinct factors need to be present for the Kirby Upper Mannville II gas pool to be affected by shear or tensile fracturing of the confinement strata induced by SAGD operations:

- Fractures (shear or tensile) would need to be created by start-up-induced hydraulic fracturing during the initial stages of SAGD operations or from deformation over long-term SAGD operations.
- Any fractures that occur would need to form a connected pathway through the overlying confining strata and into the Kirby Upper Mannville II gas reservoir.
- The fractures would need to act as open conduits for steam or reaction products from the SAGD operations to travel upward through the confinement strata.

[107] There is an additional factor about the existing state, namely any naturally occurring fluid pathways, such as pre-existing (natural) fractures, or whether no effective barrier to fluid migration exists. This factor has already been discussed in the sections above and is not repeated here.

[108] Based on the submissions and testimony during the hearing, we note Canadian Natural changed its requested start-up procedure to include the following limitations:

- a temporary MOP of 6600 kilopascals (kPa) to initiate circulation

- a maximum continuous time of 24 hours when using bottomhole pressures above 5500 kPa and below the temporary MOP of 6600 kPa on 14 nonconsecutive days
- a maximum gross steam rate of 180 cubic metres per day (m^3/d) cold water equivalent when using bottomhole pressures above 5500 kPa

[109] Canadian Natural also modified its requested long-term MOP from 6000 to 5500 kPa.

Potential for Start-Up-Induced Fracturing During the Initial Stages of SAGD Operations

[110] Canadian Natural explained the fracture containment mechanisms that limit potential fracture growth, including

- leakoff within the McMurray reservoir,
- a stress contrast between the McMurray reservoir and the confinement strata,
- poroelastic stress increases within the McMurray reservoir, and
- limited rate and volume injected with elevated pressures.

Canadian Natural emphasized that its geomechanical modelling confirmed that the risk of fracturing through the confinement strata during start-up with bottomhole pressures up to 6600 kPa is low due to the multiple fracture containment mechanisms.

[111] We agree that, in general, these mechanisms help limit or constrain fracture propagation; whether a fracture can be contained depends on the magnitudes of these factors. We further agree there are uncertainties, given the potential variation in the in situ stresses within the confinement strata. We also agree that a stress contrast exists between the McMurray reservoir and the McMurray shales. We accept Canadian Natural’s modelling results that show that when considering all the mechanisms, the potential for induced fracturing through the confinement strata is low for the proposed start-up MOP, injection rate, and duration of the start-up operations.

[112] We note that ISH acknowledged Canadian Natural’s detailed analysis of initial fracturing and had no issue with Canadian Natural’s modelling of fracture containment within the McMurray during the start-up of the SAGD process. ISH’s geomechanics witness also confirmed that Canadian Natural’s work with the temporary MOPs was convincing, so he did not have a problem with it.

[113] Canadian Natural presented evidence of its experience in starting circulation on 146 wells in the Kirby North area, and of those wells, only one exhibited characteristics of potential fracturing. We find this level of operational experience significant for understanding the regional stress variations in the McMurray post-B2 reservoir in the Kirby North area and corresponding evidence of a low potential for start-up-induced fracturing.

[114] We note that ISH agreed that the historical Kirby North area circulation start-up data can be used to understand stress variations in McMurray sands in the Kirby North area. We agree that this historical circulation start-up data supports the regional stress consistency within the post-B2 reservoir.

[115] We also note that Canadian Natural found that using regional diagnostic fracture investigation tests (DFITs), it can be concluded with a high degree of confidence that McMurray shales have a stress contrast relative to the McMurray sands that exceed 0.5 kPa/m. ISH agreed that shaley or muddy zones typically have higher horizontal in situ stress gradients than the underlying sandy zone due to strata with a higher mud content having a higher Poisson's ratio. We interpret this to mean that there is concurrence between the parties that a stress contrast exists between the mud-prone confinement strata and the post-B2 reservoir sand.

[116] Canadian Natural explained that safety factors for the temporary MOP are built-in by the limited duration and limited volumes used for potential bottomhole pressures above 6000 kPa plus operational and procedural enhancements for KN08 and KN09. We note ISH did not express concerns regarding the safety factors. In our view, Canadian Natural’s proposed safety factors for the temporary MOP, including the comprehensive list of operational and procedural enhancements, are based on significant operational experience in the Kirby North area.

[117] Considering the evidence presented and concurrence by ISH regarding the low potential for start-up-induced fracturing through the confinement strata, we find that Canadian Natural’s proposed start-up procedures, temporary MOP of 6600 kPa with limited injection rate and duration, and associated safety factors acceptable, as reflected in the conditions and commitments listed in appendix 2.

Impact of Long-Term SAGD Operations on the Confinement Strata Integrity

[118] We note ISH’s contention that the evidence provided was not sufficiently refined to inform detailed assessments of the behaviour of the heterogenous confinement strata and the development of potential fluid migration pathways over the life of the SAGD project, in particular, because of stratigraphic uncertainties and lithologic variability within the confinement strata.

[119] We also note Canadian Natural’s contention that the temporary MOP of 6600 kPa with limited injection rate and duration and the 5500 kPa long-term SAGD MOP are sufficiently constrained to mitigate the risk of hydraulic fracturing into the Kirby Upper Mannville II gas pool. The long-term proposed operating conditions for the drainage boxes are low risk to the confinement strata integrity.

[120] We further note that there is agreement between the parties that strata with higher mud content will have higher horizontal in situ stress gradients. We also note that ISH’s geomechanics witness agreed with the in situ stress consistency in the McMurray sands and the stress contrast between the McMurray reservoir sands and the McMurray shales.

[121] Regarding the potential for induced shear or tensile fractures over the long-term SAGD operations, we note Canadian Natural's disagreement that the proposed SAGD operations will result in transmissive flow paths through the confinement strata during the lifetime of the planned operations. Canadian Natural evaluated the risk of shear and tensile failure using geomechanical modelling and concluded that the proposed operating conditions are reasonable to maintain the integrity of the confinement strata.

[122] We further note that ISH disagreed with Canadian Natural's modelling because the model did not sufficiently represent the degree of heterogeneity of the strata overlying the McMurray reservoir.

[123] We agree that it is reasonable to assume some uncertainties exist in Canadian Natural's model concerning lithologic heterogeneity, which may cause in situ stress and rock property variations, and the potential effects of the absence of mid-B1 and A2 mudstones.

[124] However, in our view, the overall likelihood is low for induced fluid pathways through the confinement strata due to the proposed long-term SAGD operations. Canadian Natural's geomechanical modelling (based on the current interpreted in situ stresses and potential stress range in the mud-prone strata) predicted a low risk for induced shear or tensile failure of the confinement strata for the proposed SAGD operations. The model was based on a SAGD operating pressure of 4000 kPa for 15 years, with an occasional increase in the operating pressure to 6000 kPa for 30 days. The modelled SAGD operation indicated the proposed operations would have a low impact on the integrity of the confinement strata. Given that a stress contrast, likely exceeding 0.5 kPa/m, exists between the McMurray shales and McMurray sands and regional stress consistency was observed in the McMurray sands (approximately 13.1 kPa/m), the potential range of stress variation in the mud-prone confinement strata can be reasonably estimated.

[125] Based on the evidence presented, we accept there are additional factors that may further lower the risk, namely:

- The SAGD operating pressure is balanced with the McMurray bottom water pressure, which is currently 2600 kPa, lower than the modelled 4000 kPa, and history has shown that operating pressures do not exceed 500 kPa above the initial bottom water pressure over a long period.
- The proposed long-term MOP of 5500 kPa is for dealing with short-term operating interruptions over the life of the drainage boxes.

[126] We further note and accept Canadian Natural's explanation that in the area of the drainage boxes, the current McMurray bottom water pressure gradient (5.5 kPa/m, or approximately 2600 kPa) is well below the minimum stress gradient of the post-B2 reservoir sand and the SAGD steam chamber pressure gradient precludes hydraulic fracturing of the confinement strata.

[127] Regarding the potential for development of shear fractures being open and creating conduits for fluid migration, we note ISH's contention that the materials that make up the confining strata will generally exhibit a brittle or post-peak strength softening behaviour with shear deformation created from the imposition of stress changes due to steam chamber development and that this could create transmissible pathways for fluid to migrate between the higher pressure SAGD chamber and the Wabiskaw B gas sands and the Upper Mannville II gas pool.

[128] We accept ISH's contention that in the absence of core testing specific to KN08 and KN09, there is uncertainty regarding the potential quantification of brittle and ductile transition behaviour for the fine-grained zones within the confinement strata. We note, however, that ISH's geomechanics witness agreed that a material with brittle or post-peak strength softening behaviour upon shear deformation may exhibit non-dilatant behaviour and for the class of materials that make up the confinement strata, at an effective stress above 1470 kPa, the behaviour is not indicative of open fractures. The effective in situ stress of the mud-prone confinement strata at the depth of the confinement strata in the drainage boxes is higher than 1470 kPa. He also agreed that lab tests on MacKay-area Wabiskaw D specimens showed no measured permeability increase associated with induced shear failure. In other words, shear failure may not create transmissible fluid pathways.

[129] We agree that, in the unlikely event of induced shear failure in the confinement strata, it may not create transmissible fluid pathways because it is likely that the confinement strata will exhibit non-dilatant behaviour at an effective stress above 1470 kPa.

[130] Therefore, in reviewing the factors that would need to be present for the Kirby Upper Mannville II gas pool to be affected by shear or tensile fracturing within the confinement strata induced by SAGD operations, we find the following:

- The likelihood is low for induced shear or tensile fractures created through the confinement strata.
- The likelihood is low that induced fractures form a connected pathway through the overlying strata would cause SAGD steam to migrate into the Kirby Upper Manville II gas pool.
- In the event induced shear fractures occur in the confinement strata, it is possible that they will not act as open conduits for steam or reaction products from SAGD operation to migrate upward.

[131] Based on the foregoing, we are of the view that the likelihood is low of the long-term SAGD operations at the drainage boxes affecting the confinement strata to the extent that it would result in an impairment of the Kirby Upper Mannville II gas pool.

[132] Further, we agree that lowering the long-term MOP from 6000 to 5500 kPa will add a factor of safety. As such, we find that the requested long-term MOP of 5500 kPa is acceptable, as reflected in the conditions and commitments listed in appendix 2.

Approval Conditions

[133] As explained above, ISH did not object to approving the Application, indicating it sought an outcome allowing Canadian Natural to develop the bitumen resource without unreasonable and adverse effects on ISH's gas production. However, ISH advocated that if we grant the Application, we should also include conditions in the approval to protect its interests. We noted throughout this proceeding agreement on some of the proposed commitments made by Canadian Natural, but significant disagreement remains between the parties regarding the need for certain conditions requested by ISH, which are discussed below.

[134] Canadian Natural acknowledged that hydrogen sulphide 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 drainage boxes. It argued that it is a very low risk and that Canadian Natural's proposed mitigation measures are reasonable, considering related benefits and costs.

[135] As indicated above, we believe that there is minimal risk to the Kirby Upper Mannville II gas pool because, in our opinion, it is more likely than not that an aggregate of the six confinement strata, where present, will provide an effective barrier to steam migration from the drainage boxes over their operational life.

[136] We further note that, in the event the Kirby Upper Mannville II gas pool is impacted by SAGD operations, Canadian Natural has committed to compensate ISH as identified in appendix 2.

[137] In evaluating whether or not to impose the conditions that are the subject of disagreement between the parties, we considered the cost of the requested conditions versus the economic value of the remaining gas in place in the Kirby Upper Mannville II pool.

[138] We used the material balance of the original gas in place and the remaining gas in place provided in the parties' submissions to assess the value of the gas resource at risk.

[139] Both parties agreed that the present remaining gross (100% working interest) volume of remaining gas in place for the Kirby Upper Mannville II pool is approximately 2.95 billion cubic feet.

[140] Both Canadian Natural and ISH have confirmed that their respective working interests in the Kirby Upper Mannville II pool are as follows: Canadian Natural 53.75% and ISH 46.25%. Therefore, the remaining gas in place proportioned between ISH and Canadian Natural, using both volumetrics and material balance, is approximately 1.37 billion cubic feet for ISH and 1.59 billion cubic feet for Canadian Natural.

[141] ISH provided an estimated value of 100% of the remaining gas in the Kirby Upper Mannville II pool of $3.685 million, effective January 1, 2024. ISH declined to apply a discount to this value in recognition of the passage of time between the effective date of the estimate and when the gas in the pool

may be expected to be produced. ISH did not apportion the estimated value based on the respective working interests in the pool, but if applied, the result is a value of $1.70 million to ISH and $1.98 million to Canadian Natural for their respective interests in the gas as of the effective date.

[142] We further note that Canadian Natural further discounted ISH's gas valuations by both 10 and 20 years in order to reflect the effect of gas production delayed due to ongoing GOB orders and reasonable SAGD operational timeframes. In contrast, most of the mitigation costs incurred by Canadian Natural will occur in the near term, generating a more immediate effect on the value of the KN08 and KN09 developments.

[143] With respect to the costs related to the mitigation requested by ISH, Canadian Natural contended that ISH's requested costs summed to $6.237 million versus Canadian Natural's estimated commitments which amounted to $1.110 million. We note these cost estimates compare with ISH's estimated value of its share of the remaining gas in place $1.70 million.

[144] We are of the view that these near-term costs are disproportionate to the value of the gas that could be potentially impacted. Therefore, in light of the above cost-benefit analysis and the findings and discussion in the following sections, we are disinclined to impose any additional conditions requested by ISH beyond those already agreed to by Canadian Natural during this proceeding.

Areas of Agreement

[145] During this proceeding, we noted that Canadian Natural and ISH reached agreement on some matters, which will be discussed below. These include monitoring of the Kirby Upper Mannville II gas pool, hydrocarbon-assisted start-up, and thermally compatible wells. Conditions and commitments related to these matters are listed in appendix 2.

Monitoring the Kirby Upper Mannville II Gas Pool

[146] There was an ongoing discussion of monitoring requirements for the KN08 and KN09 development before and during this proceeding. Before this matter was directed to a hearing, the AER provided draft approval conditions, including monitoring requirements, to Canadian Natural and ISH for review and comment. Both parties addressed monitoring requirements in their hearing submissions and testimony.

[147] ISH proposed the following monitoring condition: minimum one per pad observation/gas monitoring well with piezometers on casing outside and multipoint thermocouples to monitor Wabiskaw B gas, Clearwater caprock, and the Wabiskaw D and McMurray Formations.

[148] When the hearing closed, Canadian Natural had committed to gas monitoring at four wells: two over the KN08 drainage box, one on or in the vicinity of the KN09 drainage box, and the 10-01 well over the KN06 drainage box, previously designated for gas monitoring in the KN06 decision. ISH appeared to

be in general agreement and specifically requested that a gas monitoring well be drilled over the KN09 drainage box.

Hydrocarbon-Assisted Start-Up

[149] In this proceeding, the parties used the terms “hydrocarbon agent-assisted start-up” and “solvent-assisted start-up” interchangeably. For consistency, we have chosen to use “hydrocarbon-assisted start-up.”

[150] Canadian Natural applied to use hydrocarbon-assisted start-up at the drainage boxes. The proposed steps for the application of this technology include the following:

a. Circulate the injector and producer for 30 to 90 days.

b. Inject up to 350 m^3 per well pair (maximum) hydrocarbon below 5500 kPa MOP.

c. Inject hot water and methane to displace all the injected hydrocarbon from the well into the reservoir.

d. Shut in the wells for one to five days.

e. Open the wells and perform circulation and/or semi-SAGD.

f. Convert the wells to SAGD operation.

[151] Canadian Natural explained that the injected hydrocarbon is expected to stay within approximately 3 m of the wellbore region, be fully dissolvable in the bitumen, and will be produced back in the very early stages of production. In Canadian Natural’s view, controlled injection of relatively small amounts of hydrocarbons during start-up, which will be injected below the long-term MOP of 5500 kPa, makes the risk to the overlying gas resource from this assisted start-up extremely low.

[152] We note apparent agreement among the parties that hydrocarbon-assisted start-up has significant benefits. ISH cited the following benefits:

- Mobilize the near-wellbore region around the injector and producer faster and more efficiently than with steam alone.
- Improve steam conformance along the horizontal length of the wells.
- Accelerate bitumen production by converting wells to SAGD mode faster.

[153] We agree with Canadian Natural’s description that hydrocarbon-assisted start-up is more akin to well stimulation. We also note that Canadian Natural does not plan to use hydrocarbon-assisted start-up on all well pairs, perhaps only on every second well pair.

[154] In our view, because the injection of hydrocarbons takes place predominantly during the initial start-up phase of the wells and is not an ongoing reservoir stimulation process occurring continuously over the life of the drainage boxes, we agree that the potential for ISH’s interest in the gas reserves to be affected is greatly reduced.

[155] We heard Canadian Natural’s explanation that the relatively small volume of injected hydrocarbon will occupy less than 2% of the pore space in the near-wellbore region and is expected to stay within a 3 m radius of the wellbore.

[156] Because steam circulation is conducted for a relatively short period (about 30 to 90 days) to heat the wellbore region and stopped before hydrocarbon is injected, and the injection volumes and pressures will be controlled to stay below the 5500 kPa MOP, it will not create additional geomechanical risk. We further note that the temporary MOP of 6600 kPa will not be used during the hydrocarbon-assisted start-up stage.

[157] In our view, it is an important factor that the hydrocarbon (xylene) is soluble in bitumen and, therefore, expected to combine with the bitumen and be produced back in the early days of SAGD production. Because the hydrocarbon is insoluble in water, it is unlikely to be entrained in steam and migrate through the bitumen reservoir and any overlying confining strata if conduits were present.

[158] Canadian Natural has requested a maximum hydrocarbon volume of 350 m^3 per well pair to provide flexibility for the potential maximum length of the KN08 and KN09 well pairs. We are not convinced that the evidence from ISH proves that this is an unreasonable volume.

[159] Considering the above factors, we find that there are considerable benefits to using hydrocarbon-assisted start-up at the drainage boxes.

[160] Also, based on the foregoing, we find the likelihood of injected hydrocarbons migrating through the bitumen reservoir into overlying strata very remote. As such, we approve the use of a hydrocarbon-assisted start-up, according to the defined parameters proposed by Canadian Natural and subject to the conditions and commitments in appendix 2.

[161] We also note ISH’s agreement to drop its request for a condition pertaining to “solvent monitoring,” and we will, therefore, not require solvent monitoring conditions.

Thermally Compatible Wells

[162] In accordance with section 7.8 of *Directive 023* and the requirement for well integrity in the Kirby commercial scheme approval (condition number 13), Canadian Natural reviewed wellbore construction and past abandonment practices used on all wellbores within a 300 m radius of the proposed drainage boxes.

[163] The following four wells were identified as not compatible with thermal operations. Canadian Natural defined non-compatible wells as wellbores that steam cannot be directly injected into but can safely reside within operating steam chambers:

- 00/10-34-074-09W4/0
- 00/10-02-075-09W4/0 & /2
- 00/10-03-075-09W4/0
- 00/12-34-074-09W4/0

[164] We note from the submissions and information presented during the hearing that ISH and Canadian Natural appear to agree on how the four wells will be remediated to make those wells compatible with thermal production. We find the agreed-on actions generally acceptable, subject to the conditions and commitments in appendix 2.

[165] During the hearing, both parties responded to AER questions about ensuring isolation behind the production casing in the wells. The actions proposed to ensure thermal compatibility did not address AER concerns about isolation behind production casing. As such, we have decided to impose an approval condition (see appendix 2) requiring proof of isolation behind production casing for wells that are not compatible with the proposed thermal operations to ensure SAGD fluids will be contained within the McMurray SAGD formation.

Areas of Disagreement

[166] We address in this section the following conditions requested by ISH that were not agreed to by Canadian Natural: a new DFIT, surface gauges for monitoring wells, and gas compositional sampling during the operational life of the drainage boxes.

Whether or Not a New DFIT is Required

[167] We heard during the hearing that a DFIT is used to determine the principal in situ stress that can be used for either leveraging some geomechanical effects for a resource recovery process or for assessing caprock integrity and confinement strata integrity.

[168] ISH contended that a new “modern” DFIT is needed to determine whether the MOPs are sufficient to prevent the creation of transmissive fluid pathways in the confinement strata.

[169] ISH requested a new DFIT in the immediate KN08 and KN09 areas for the following reasons:

- The geological setting may be different than the location of the previous DFIT used to determine the in situ stress state for the KN06 and KN07 areas, which was about six kilometres east of KN06.

- The A2 and mid-B1 mudstones are present across all the wells in the current DFIT data but are absent or variable over a large part of the KN08 and KN09 drainage boxes.
- If the newly acquired minimum stress value is lower than Canadian Natural estimated, the risk for the confinement strata to fail is higher.
- The new DFIT results will be used to determine the long-term MOP.
- It is in the public interest to acquire the additional DFIT, given the large uncertainties regarding the geology, the absence of well control, and the distance to the next DFIT data point.

[170] Canadian Natural disagreed that a new DFIT was necessary and maintained that adequate stress characterization exists for the Kirby North area for the following reasons:

- In situ stresses tend to be regionally consistent.
- Significant geological structural or tectonic features are not present over the KN08 or KN09 drainage areas.
- The historical Kirby North well data set for circulation start-ups for 146 SAGD wells in the Kirby North area did not show indications of hydraulic fracturing at various pressures. Only one of those wells exhibited characteristics of potential fracturing, and the pressures were consistent with the stresses determined by the regional DFITs. This supports there being more consistent regional stress gradients for a specific geological unit.
- The historical Kirby North well data set for circulation start-up data can be used to understand McMurray stress variations in the Kirby North area, which was agreed to by ISH's geomechanics witness.
- Higher mud content strata have higher horizontal in situ stress gradients. A stress contrast exists between the mud-prone confinement strata and the post-B2 reservoir sand. Regionally present mud-prone strata, such as the regional B1 sequence, do not require higher density testing due to the consistent elastic properties.
- A DFIT would require a vertical wellbore, and Canadian Natural currently has no vertical standing cased wells suitable for a DFIT. A new vertical well would need to be planned, licensed, and drilled, which could delay the project by one to two years because of winter access requirements.
- The estimated cost of a new stratigraphic well, including the DFIT, would be $1.11 million; the estimated cost of conducting an additional DFIT is not justified.
- The proposed long-term MOP was reduced from an acceptable 6000 kPa to 5500 kPa, which increases the factor of safety.

- A new DFIT would not change the requested MOP.

[171] We find it is reasonable to assume that a new DFIT within the KN08 and KN09 project area would provide more certainty in determining minimum in situ stresses and help to determine an MOP based on in situ stresses for the local area.

[172] However, we are puzzled by ISH's request for a new DFIT to determine a local MOP, considering that Canadian Natural plans to operate the SAGD wells at pressures in the range of 2500 – 4000 kPa, which is considerably lower than the requested long-term MOP of 5500 kPa.

[173] Canadian Natural conducted reservoir and geomechanical modelling to evaluate the effect on the confinement strata by a SAGD operating pressure of 4000 kPa over 15 years, with an occasional temporary increase in SAGD operating pressure to 6000 kPa for 30 days. The modelling confirmed a negligible effect on the confinement strata integrity from a short-term (i.e., 30 days) operating pressure increase up to 6000 kPa. The model indicated that further reducing the MOP will not significantly lower the likelihood of induced shear or tensile failure if the MOP is used for a short term.

[174] We note Canadian Natural's statement that the proposed long-term MOP of 5500 kPa is for managing short-term operating interruptions over the life of the SAGD pads. Canadian Natural further explained that in the Kirby area, the SAGD historical operating pressures do not exceed 500 kPa above the initial bottom water pressure of approximately 2600 kPa. Based on the current bottom water pressure, we interpret this to mean that the operating pressure will likely be below 4000 kPa.

[175] In addition, we note that a new DFIT will not provide information that has been the subject of some debate during this proceeding. For example, a new DFIT will not resolve the uncertainties about the heterogeneities in the strata overlying the McMurray post-B2 reservoir to the base of the Wabiskaw B, nor will it provide information on rock properties, such as elastic properties, across different lithologies, or how the model should be refined to a scale that better represents the behaviours of the heterogeneous system.

[176] It is also important to note that a new DFIT will not resolve the uncertainties regarding the presence or absence of the A2 and mid-B1 mudstones.

[177] Canadian Natural explained that a new DFIT would require drilling a new vertical well that could delay the start of SAGD operations by as much as one to two years, and at a cost which, in Canadian Natural's view, is disproportionate to the value of the remaining gas reserves of the Kirby Upper Mannville II gas pool. In our view, because Canadian Natural is a part-owner of the gas reserves in the Upper Mannville II gas pool, this cost-benefit estimate is credible, and, as such, we accept Canadian Natural's estimate of the costs associated with conducting a new DFIT.

[178] Considering the above factors, we find that a new DFIT is not warranted. In our view, the evidence, including Canadian Natural's operational experience in the Kirby North area, demonstrates that the stresses are regionally consistent in the McMurray sands and that the stress variation range in the mud-prone confinement strata in the Kirby North area can be reasonably estimated. We also find that a new DFIT will not resolve uncertainties about heterogeneities in the strata overlying the McMurray post-B2 reservoir to the base of the Wabiskaw B; uncertainties relating to the presence or absence of certain stratigraphic units or lithologies will remain.

[179] Further, in our opinion, the delay of the project combined with the significant estimated cost versus the value of the remaining gas reserves does not justify a new DFIT in the KN08 and KN09 areas.

[180] Lastly, we disagree with ISH that a new DFIT is in the public interest, considering the potential delay it would create and the effect on SAGD operations and bitumen recovery associated with this project. In our view, ensuring the integrity of the Clearwater Formation caprock for the overall region is in the public interest. However, if the objective of a new DFIT, as contended by ISH, would be to ensure the integrity of the confining strata between the McMurray and the Kirby Upper Mannville II gas pool, for which ISH has a financial interest, we view this as narrower than the public interest.

Surface Gauges for Monitoring Wells

[181] ISH proposed a condition requiring installation of surface gauges around all monitoring wells "to help verify downhole pressure information and give an added check on what is happening downhole." Beyond suggesting that surface recorders would provide a double-check on results from downhole gauges, ISH did not provide evidence supporting this proposed condition.

[182] Canadian Natural disagreed with the requested condition, indicating that it actively responds to and mitigates all downhole gauge issues and thus does not believe surface gauges are needed.

[183] Given Canadian Natural's response to downhole gauge concerns and ISH's lack of justification for this request, we will not require Canadian Natural to install surface gauges on monitoring wells.

Gas Compositional Sampling

[184] ISH proposed a condition requiring Canadian Natural to collect gas samples after the SAGD operation start-up and over the life of the drainage boxes. ISH indicated that it would prefer to have gas composition data points between sampling to occur before SAGD starts and at the end of SAGD, such as annually, to monitor changes in gas composition. In response to the AER's questioning at the hearing, ISH acknowledged that if the gas is contaminated, there is nothing ISH could do; the only appropriate remediation would be to reduce steam rates to attempt to minimize the impact on the gas.

[185] At the hearing, Canadian Natural indicated it was willing to take baseline samples from a well over the KN08 and KN09 areas and another sample before production of the gas for comparison purposes. ISH indicated its agreement to this sampling.

[186] Canadian Natural did not support ongoing gas sampling over the operational life of the drainage boxes. It indicated that the second gas sample it committed to collect before gas production would allow adequate comparison to baseline samples and determine any potential impacts on gas composition. Canadian Natural submitted that ongoing gas sampling would add little actionable value beyond that provided by four existing gas monitoring wells and ongoing SAGD monitoring.

[187] From the evidence, in our opinion, once steaming starts on SAGD operations, compensation can address any potential effects on the Kirby Upper Mannville II pool. We are persuaded by Canadian Natural's comment above that ongoing gas sampling would add little value to the information gathered from the existing gas monitoring wells and ongoing SAGD monitoring.

[188] We acknowledge the agreement between the parties regarding taking baseline samples from a well in the KN08 and KN09 areas and another sample before the production of the gas for comparison purposes; however, we will not require Canadian Natural to collect gas samples over the operational life of the drainage boxes.

Requested Condition About Compensation Commitment

[189] ISH asked us to impose an approval condition requiring Canadian Natural to honour its commitment to compensate ISH if the overlying gas becomes contaminated. ISH suggested that the AER could impose such a condition as part of our overarching authority to make any condition in the public interest.

[190] In response, Canadian Natural suggested that making such a commitment a condition of approval would be unusual.

[191] Similar to the KN06 decision, we are informed by the EUB 1998 inquiry and the GOB decision and find that where there may be an impact on the Kirby Upper Mannville II gas pool, the impact would be financial in nature and could be addressed by monetary compensation.

[192] If contamination occurs, we expect Canadian Natural will honour its commitment to provide appropriate compensation to ISH as set out in appendix 2. However, we decline to make this expectation a condition of this amendment approval. To do so would be a change from the AER's past practice, and we are not convinced that this case's circumstances merit a change from that practice. It would be impractical and difficult for the AER to enforce such a condition since potential damages may not occur for 20 years or more. In addition, we view the protection of a party's financial interest as narrower than the public interest.

Conclusion

[193] Canadian Natural applied to amend the approval for its Kirby North in situ development by adding SAGD drainage boxes KN08 and KN09. ISH and Canadian Natural have shared interest in the Kirby Upper Mannville II gas pool overlying the bitumen Canadian Natural plans to develop.

[194] Production of that gas pool has been shut in since 2004 under EUB direction following the EUB's (the predecessor to the AER) review of gas-over-bitumen concerns. The EUB's reviews and subsequent EUB and AER regulatory decisions confirmed that prioritizing bitumen production ahead of overlying associated gas is in the public interest and that potential damage to that gas from bitumen production could be remedied by financial compensation.

[195] ISH did not object to approving the Application. It sought an outcome allowing Canadian Natural to develop the bitumen resource without unreasonable and adverse effects on ISH's interest in the Kirby Upper Mannville II gas pool.

[196] In this proceeding, we needed to decide whether Canadian Natural's Application was in the public interest. In making that determination, we considered whether the Application meets technical and regulatory requirements. We also considered whether approval conditions or other mitigation measures are required to ensure the appropriate conservation of the Kirby Upper Mannville II gas pool. We decided that to uphold the AER's mandate to ensure the efficient, safe, and orderly development of energy resources, there must be a balance between the costs and benefits of any mitigation measures.

[197] We believe the existing regional caprock, consisting of the Clearwater and Wabiskaw A shales, will protect the overlying Grand Rapids Formation and shallower formations from SAGD steam migration. Neither party disputed the effectiveness of these units as a regional caprock, and in our view, maintaining the integrity of the regional caprock is clearly in the public interest.

[198] Having considered the parties' extensive evidence and submissions, we found that the six confinement strata proposed by Canadian Natural will more likely than not provide effective containment of SAGD steam at the KN08 and KN09 drainage boxes, preventing effects on the Kirby Upper Mannville II gas pool over the life of the SAGD operations.

[199] We also found that induced fracturing from the start-up stages of SAGD operations and long-term SAGD operations is unlikely, considering Canadian Natural's proposed MOP and protective measures.

[200] Where the parties agreed on the approval conditions, we imposed the relevant conditions noted in appendix 2. The parties disagreed on some approval conditions requested by ISH. We assessed several factors associated with ISH's requested conditions, including the estimated cost of those conditions compared with the economic value of the remaining gas in place in the Kirby Upper Mannville II gas pool. Based on our assessment of the information presented, we declined to impose any disputed

conditions. We are of the view that conditions intended to protect a party's financial interests are narrower than the public interest.

[201] We noted Canadian Natural's commitment to compensate ISH if the SAGD operations were to contaminate the Kirby Upper Mannville II gas pool and expect Canadian Natural to honour that commitment if contamination occurs. However, we declined to include this expectation in an approval condition, as requested by ISH. Consistent with guidance from previous EUB and AER decisions, we believe that damage to overlying gas from bitumen can be remedied by financial compensation to be determined between Canadian Natural and ISH if such future damage occurs.

[202] As discussed previously, no concerns were raised about social or environmental effects or impacts on landowners from the Application. It is clear from our analysis and reasons above that we have considered the economic effects of the Application, including the benefit of developing the bitumen resource and that the impact on ISH's economic interest in the overlying gas is unlikely. Having carefully considered all the evidence, we approve application 1936092 as being in the public interest subject to the conditions in appendix 2.

Dated in Calgary, Alberta, on May 8, 2024.

Alberta Energy Regulator

Cindy L.F. Chiasson, LL.B.
Presiding Hearing Commissioner

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

M.A. (Meg) Barker, P.Geol.
Hearing Commissioner

Appendix 1 Hearing Participants

Principals and Representatives (Abbreviations used in report)	Witnesses
Canadian Natural Resources Limited: J. Jamieson, Legal Counsel	D. Ollenberger T. Boone L. Roche M. Scrimshaw G. Iannattone J. Lavigne S. Sverdahl D. Walters X. Wang P. Thomsen S. Barland
ISH Energy Ltd.: M. Riley, Legal Counsel A. McLeod, Legal Counsel	M. Fowler B. Barrie A. Lagisquet R. Chalaturnyk J. Chodzicki K. Vickerman
Alberta Energy Regulator staff: W. McClary, AER Counsel S. Peddlesden, AER Counsel A. Lung D. Parsons A. Stanislavski E. Arruda T. Wheaton F. Hamdan M. Rahimabadi S. Harbidge	 M. Xhaferllari F. Chiang S. Botterill B. Yang E. Galloway J. Douziech C. Sandau

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 11475WW are summarized below. The approval conditions listed below are provided for information purposes in support of the panel's decision. The numbering of the approval conditions below may be inconsistent with the numbering of the conditions in the approval document that will be issued to Canadian Natural.

Proceeding 430 (KN08 and KN09 Development)

47) Prior to commencing steam circulation at Pads KN08 and KN09 within the Kirby development area outlined in Appendix A, the Operator shall submit a monitoring strategy satisfactory to the AER for continuous SAGD operations.

a) The strategy shall, at a minimum, provide for
   i) continuous temperature and pressure monitoring within the Upper Mannville II gas pool with the 100/01-03-075-09W4/02 and 100/10-34-074-09W4/0 wells within the drainage area of KN08 and at least one gas monitoring well within or in proximity to the drainage area of KN09, in addition to the 00/10-01-075-09W4/0 well.
   ii) a gas compositional baseline analysis for the Kirby Upper Mannville II pool taken directly above the KN08 drainage area or directly above or in close proximity to the KN09 drainage area.

b) The strategy should include the use of interpreted maps and/or cross-sections of 4D seismic data, where it is available.

48) Prior to commencing steam circulation at Pads KN08 and KN09 within the Kirby development area outlined in Appendix A, the Operator shall submit drilling, completion, and cementing data or cement bond logs for existing cased wells that might be impacted by the proposed thermal operation in the area proving to the AER's satisfaction that there is isolation behind the production casing in the wells from the McMurray Formation to the surface casing shoe.

49) During start-up, circulation, and SAGD operations at Pads KN08 and KN09, the Operator shall:

a) monitor temperature and pressure within the Kirby Upper Mannville II gas pool in the four monitoring wells as per clause 47, sub-clause a) i), and
   i) if any anomaly is observed, submit it in its annual Directive 054 performance report, and
   ii) submit the temperature and pressure data in its annual Directive 054 performance report.

50) For Pads KN08 and KN09, the bottomhole injection pressures must not exceed 5,500 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 6,600 kPa (gauge) for a maximum continuous duration of 24 hours and a cumulative duration no more than 14 nonconsecutive days, and a maximum gross steam injection rate of 180 m^3/d (Cold Water Equivalent) per well when using bottomhole pressure above 5,500 kPa in order to displace liquid in the wellbore to commence circulation.

a) During start-up at bottomhole injection pressures above 5,500 kPa (gauge) and up to 6,600 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 adjust its injection operations immediately to minimize loss of containment of injection fluid and report it to the AER within 24 hours of detecting loss of containment of injection fluid.
b) 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 at Pads KN08 and KN09 within the Kirby development area outlined in Appendix A.
c) 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.

51) (1) The Operator may conduct a hydrocarbon-assisted start-up process, injecting hydrocarbon (xylene-diluent blend), non-condensable gas (methane), hot water, and steam in each well pair for Pads KN08 and KN09.

(2) The maximum injection pressure while conducting a hydrocarbon-assisted start-up process for Pads KN08 and KN09 must be limited to 5,500 kPa (gauge).

(3) The maximum injection volume of the hydrocarbon (xylene-diluent blend) shall not exceed 350 m^3 (at standard temperature and pressure condition) per well pair.

Commitments by Canadian Natural Resources Limited

We have considered the commitments Canadian Natural said it was prepared to make to address possible contamination of the Kirby Upper Mannville II gas pool from SAGD operations at the KN08 and KN09 drainage boxes. Although we considered these commitments in arriving at our decision and expect Canadian Natural to comply with the commitments made, these commitments do not constitute conditions of the amended approval. The commitments below are quoted directly from Canadian Natural's amendment application and submissions.

Canadian Natural will implement operational enhancement, following the start-up procedure for the KN08 and KN09 Development:

- A workshop with the Kirby North area team will be conducted at least 30 days prior to the pad startup, covering the following topics:
    - Hydraulic fracturing;
    - In situ stresses; and
    - Previous Kirby North circulation startup illustrative examples above 6,000 kPa.
- The following circulation startup strategy is proposed:
    - If wells have reached 5,500 kPa but do not unload and establish circulation after 4 hours have elapsed, then bottomhole pressures above 5,500 kPa and up to 6,600 kPa (temporary MOP) may be utilized for a maximum duration of 14 non-consecutive days in order to displace liquid in the wellbore to commence circulation while:
        - A multi-disciplinary engineering team 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.
- An engineer with geomechanics expertise will review rate and pressure records for several of the initial wells during start-up to test for an abnormal or unexpected fracturing behaviour at KN08 and KN09.

Canadian Natural is committed to gas sampling and analysis at such time that the Kirby Upper Mannville II gas is allowed to produce. This later gas sample would adequately facilitate comparison to baseline samples and determine potential impacts to gas composition, if any.

In the highly unlikely event that contaminants resulting from the KN08 and KN09 steam chamber migrate into the gas resource and cause damage, Canadian Natural is prepared to pay for cleaning of the gas or pay reasonable compensation for the damage at the time when the bitumen resource is fully depleted and the gas production from the Kirby Upper Mannville II pool is allowed to resume.

In the event that cleaning the gas is determined to be cost-prohibitive, Canadian Natural committed that it could assess connecting the gas to the SAGD infrastructure and burn the gas as fuel in the steam generators or pay reasonable compensation for damage. Canadian Natural stated ISH would be fairly compensated for its share of the gas at that time.